BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN INVESTIGATION OF INTER-JURISDICTIONAL ISSUES	)))))	Docket No. 02-035-04 SUPPLEMENTAL TESTIMONY AND EXHIBITS

MAY 2004

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IN THE MATTER OF THE	)	Docket No. 02-035-04
APPLICATION OF PACIFICORP	)	
FOR AN INVESTIGATION OF	)	SUPPLEMENTAL TESTIMONY
INTER-JURISDICTIONAL	)	OF ANDREA L. KELLY
ISSUES	)	

MAY 2004

Q. Ms. Kelly, did you previously file testimony in this proceeding?

A. Yes. My Direct Testimony was part of the Company's original filing with the Commission in September of 2003. The principal purpose of my Direct Testimony was to describe the terms of a "Protocol" document to be ratified by the Commission. The Protocol contained the terms of a proposed resolution of the PacifiCorp interjurisdictional cost allocation issues that have been the subject of the Multi State Process ("MSP").

Purpose

Q. What is the purpose of your Supplemental Testimony?

A. The purpose of my Supplemental Testimony is to describe events that have occurred in the MSP since our September filing and to present a revised version of the MSP Protocol for Commission consideration.

Exhibit PP&L___(ALK-1S) is a copy of the Revised Protocol, including its Appendix A, which sets forth various defined terms. Mr. Taylor sponsors Appendices B, C, D and E to the Revised Protocol in his Supplemental Testimony. Mr. Duvall sponsors Appendix F to the Revised Protocol in his Supplemental Testimony. As with my Direct Testimony, when I use capitalized terms in my Supplemental Testimony they are intended to have the same meaning set forth in Appendix A to the Revised Protocol.

Events Since September, 2003 filing.

Q. What has occurred in the MSP since the Company's September, 2003 filing?

A. Subsequent to the filing, procedural schedules were set in Utah, Oregon and Wyoming. All of the schedules provided for discovery, prefiled testimony by other parties and ultimately formal hearings this summer. However, Commissioners and other interested parties in Utah and Oregon expressed a preference for a continued exchange of information among the States and a continued attempt to achieve a consensus solution to MSP issues. Therefore, the procedural schedules in Utah and Oregon also provided for a number of technical conferences, public meetings and meetings among Commissioners from different states – all aimed at achieving consensus among the parties. To further the exchange of information and perspectives, representatives of the Oregon Commission Staff and the Utah Division of Public Utilities participated in several meetings. In April, 2004, Commissioners in Oregon and Utah concluded that the process would benefit from the further involvement of Robert Hanfling as a mediator. After Mr. Hanfling was reengaged, he participated in a number of meetings with individual parties and groups and presided over four multi-party meetings during late April.

Q. Did these informal meetings afford the Company an opportunity to better understand the parties' reactions to its September, 2003 filing?

A. Yes. We received a great deal of valuable feedback, much of which is reflected or incorporated in the Revised Protocol.

Q. Please summarize the major issues that were raised by parties in response to your September filing.

A. The major messages we received were as follows:

1. No party appeared supportive of the proposed form of "hydro endowment" and corresponding "coal endowment".

2. No party appeared supportive of the "coal opt-out" provision that was proposed for Oregon.

3. Many parties were concerned that provisions of the Protocol related to Special Contracts and Portfolio Resources could impinge on the right of each State to set rates

without being bound by the determinations of other Commissions.

4. Utah parties remained very concerned about including the Mid-Columbia Contracts in a "hydro-endowment" to the former Pacific Power States. Oregon parties felt strongly that they should be included.

5. Oregon parties were very concerned that it be understood that any Northwest entitlement to Hydro-Electric Resources and Mid-Columbia Contracts would be permanent. Correspondingly, Utah parties were concerned that if Northwest States received the near-term benefits of Hydro-Electric Resources and Mid-Columbia Contracts that they remain responsible for future costs of those Resources even if they become uneconomic.

6. Oregon parties remained unconvinced that cost shifts were not flowing from slower growing States to faster growing States under the Protocol. Utah parties recognized that cost shifts arising from disparate State load growth was a legitimate concern, but wished to assure that any "cure" be well understood and equitable for all States.

7. Oregon parties pointed out that there was a flaw in the provisions of the Protocol related to assigning the costs of New Resources to the loads of Direct Access Customers who were no longer being planned for by the Company.

8. Utah and Oregon parties recognized that a principal goal of the Protocol was to afford States the ability to craft their own energy policies and wished to make sure that such policies did not burden customers in other States. In addition, Utah parties wished to be assured that PacifiCorp would make locally based Company decision-makers available to support the development and implementation of such State policy initiatives.

9. Many parties reiterated the view that any MSP solution be rooted in principle and good analysis and not simply be crafted to reach a pre-conceived numeric outcome.

10. Many parties expressed a preference for an MSP solution that was as simple and understandable as possible. Concern was regularly expressed that any changes from existing practices be carefully studied so as to avoid unintended consequences.

<u>Protocol Changes</u>

Classification

Q. Does the Revised Protocol make changes in the proposed classification of Resources?

A. Yes. The original Protocol proposed to classify the Fixed Costs of simple-cycle combustion turbines as 100 percent Demand-Related. Not all parties were convinced that there was a compelling case for classifying simple cycle combustion turbines differently from other Resources. The Revised Protocol accepts this view and proposes a 75 percent Demand-Related and 25 percent Energy-Related classification. The reasons for this change are discussed in the Supplemental Testimony of David L. Taylor.

Hydro-Endowment

Q. How does the Revised Protocol deal with the previously proposed form of hydro endowment and corresponding "coal endowment"?

A. The concept of a hydro endowment is preserved but implemented in a different form. The coal endowment has been eliminated.

Q. How is the hydro endowment implemented in the Revised Protocol?

A. The Revised Protocol introduces a new concept of affording States value from their allocated share of Hydro-Electric Resources and Mid-Columbia Contracts through a "embedded cost differential" calculation. The Supplemental Testimony of Messrs. Taylor and Duvall describe in detail how the calculation is made. However, generally speaking, this method compares the total embedded cost of Hydro-Electric Resources and Mid-Columbia Contracts on a dollar per MWh basis with the total embedded cost of the Company's other Resources (excluding the costs of Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts). The difference in cost is then multiplied by the normalized output from the Hydro-Electric Resources and the Mid-Columbia Contracts. If the difference is negative (the Hydro-Electric Resources and Mid-Columbia Contracts costs are less expensive than other Resources), it is credited to the States with the hydro endowment. If the difference is positive (the Hydro-Electric Resources and Mid-Columbia Contracts costs are more expensive than other Resources), there is a charge to the hydro endowment States.

Q. Why are the costs of Existing QF Contracts excluded from the calculation of the Company's embedded cost of Resources when performing this calculation?

A. Existing Qualifying Facilities are also subject to an "endowment" which I discuss later in my testimony.

Q. What issues have arisen regarding the inclusion of the Mid-Columbia Contracts in the hydro endowment?

A. Allocating the benefits of the Mid-Columbia Contracts has been one of the most controversial subjects dealt with in the MSP. Parties in Oregon and Washington see little distinction between Hydro-Electric Resources and the Mid-Columbia Contracts. They observe that the original Mid-Columbia Contracts were structured in a way that affords PacifiCorp rights and responsibilities similar to ownership of a share of the Mid-

Columbia projects. They also note that the social costs and cultural concerns associated with the Mid-Columbia projects are of unique interest to Oregon and Washington. Utah parties respond by pointing out that for most of the time since the Pacific Power/Utah Power merger, the Mid-Columbia Contracts have been treated as System Resources with all States supporting the costs of these contracts.

Q. How does the Revised Protocol resolve these issues?

A. The Revised Protocol seeks to balance the parties concerns. All States are afforded a share of the costs and benefits of the Mid-Columbia Contracts. However, shares assigned to Oregon and Washington are larger than would be the case if they were treated as System Resources. Mr. Duvall's Supplemental Testimony provides specifics regarding the calculation of each State's allocated share related to the Mid-Columbia Contracts.

QF Contracts

Q. You previously mentioned that Existing QF Contracts are also subject to a unique treatment. Please explain what is proposed.

A. The embedded cost differential method is used to compare the average annual costs of Existing QF Contracts located in each State with the average embedded cost of the Company's other Resources (excluding the costs of Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts). The difference in cost is then multiplied by the normalized output from the Existing QF Contracts. If the difference is positive (the Existing QF Contracts are more expensive than other Resources), there is a charge to the State in which the QF is located. If the difference is negative (the Existing QF Contracts are less expensive than other Resources), the State receives a credit for the amount of the difference.

Q. Why is the adjustment for Existing QF Contracts being proposed?

A. Existing QF Contracts have substantially different prices in different States, reflecting different State policies that were in effect at the time they were entered into. 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. Also, because Existing QF Contracts in Oregon have higher prices than those in Utah, this adjustment tends to balance the revenue requirement impact of the Revised Protocol. It appears that Oregon parties view this as reasonable, provided they can be assured that Oregon's greater entitlement to Mid-Columbia Contract benefits is not reduced in the future.

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 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.

Q. Please explain why there could be such a bias.

A. If the embedded cost differential method were applied to a New QF Contract (assuming its cost is greater than the embedded cost of existing Resources), it would have a greater impact on prices charged to customers in the State where the New QF Contract is located than would a comparable, equally priced non-QF resource that was not subject to the embedded cost differential method.

Q. How are States protected from decisions by other States that cause excessive prices to be paid for New QF Contracts?

A. Paragraph III (C) (3) (b) of the Protocol provides that "[C]osts associated with any New QF Contract which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State approving such contract".

Q. When and how will the determination be made that the price paid for a New QF Contract was excessive and that there should be a situs assignment of costs?

A. The MSP discussions did not resolve this issue. While parties seem to generally agree with the principle expressed in the Protocol, there was considerable concern that it not undermine each Commission's prerogative to establish fair, just and reasonable rates and to not be bound by the finding of another Commission. The Company is not especially comfortable with the lack of detailed procedures in the Protocol regarding New QF Contracts that exceed the cost of Comparable Resources. Hopefully, Commissions will be mindful of the importance of not permitting additional expensive QF contracts to be put in place and there will not be a need for situs cost assignment. If problems do arise, the subject would be appropriate for prompt review by the MSP Standing Committee.

Portfolio Resources

Q. What changes are made in the Revised Protocol in respect to Portfolio Resources?

A. Under the terms of the original Portfolio, costs of Portfolio Resources that were disallowed by other States were to be assigned to the State requiring the acquisition of the Portfolio Resource. MSP parties were uncomfortable with this approach because it appeared that another Commission's findings in regard to Portfolio Resources might unreasonably shift costs to the State mandating the Portfolio Resource and limit that State's rate setting prerogatives.

Q. How were these issues resolved?

A. The Revised Portfolio treats Portfolio Resources in the same manner as New QF Contracts. It establishes the basic principle that costs of Portfolio Resources which exceed the costs of Comparable Resources available to the Company will be assigned on a situs basis. As with New QF Contracts, the Revised Protocol does not describe procedures that will cause this to occur. Again, if Portfolio Resources become a significant issue, the matter will have to be taken up by the MSP Standing Committee.

Direct Access

Q. What changes were made in the Revised Protocol in respect to Direct Access Programs?

A. The original Protocol proposed that the costs of all Resources be allocated on the basis of State load that included the load of Direct Access Customers. Oregon parties correctly pointed out that the load of Direct Access Customers who had permanently left PacifiCorp's system (and were no longer being planned for) should not be included in Load-Based Dynamic Allocation Factors for New Resources. The Revised Protocol recognizes this distinction. The Revised Protocol also recognizes that some customers may make a permanent election to have some or all of their load served by the Company based upon a market rate rather than a traditional cost-of-service rate derived from the cost of the Company's Resources. The definition of "Direct Access Customers" in the Revised Protocol is expanded to include customers who exercise such a permanent "opt-out" so that their load is excluded from Load-Based Dynamic Allocation Factors for New Resources.

Sustainability

Q. What changes were made in the "sustainability" provisions of the Protocol?

A. In the Revised Protocol, express provision is made for a "Standing Neutral" to be appointed by the MSP Standing Committee. The Standing Neutral is to facilitate discussions among States, monitor emerging issues and assist the MSP Standing Committee, as required.

As I indicated previously, Oregon and Washington parties remain very concerned about the prospect of relatively faster growing States causing a cost shift to relatively slower growing States. In an effort to alleviate these concerns, the Revised Protocol includes a commitment to analyze potential cost shifts related to faster-growing States in concert with the current IRP planning cycle. In addition, a multi-state workgroup will track key factors including actual relative growth rates, forecast relative growth rates, costs of new Resources compared to costs of existing Resources and other factors deemed relevant to this issue. The MSP Standing Committee – likely through a technical workgroup – is charged with developing a mechanism that could be implemented in a timely manner in the event that the studies show a material and sustained harm from the implementation of the IRP to slower-growing States.

Benefits of an Agreement

Q. Ms. Kelly, in your Direct Testimony, you described how the Protocol attempted to recognize and balance the various principles that had been articulated by MSP participants. Is that true as well of the Revised Protocol?

A. Yes. Of the various principles articulated in my Direct Testimony, the concept of States being afforded the ability to craft their own energy policies, while not shifting costs to other States, figures somewhat more prominently in the Revised Protocol as reflected in the treatment of QF Contracts and the provisions regarding Direct Access Programs. With the elimination of the unique classification of Simple-Cycle Combustion Turbines and the Oregon "coal opt-out" provision, the Revised Protocol furthers the principles of simplicity and ease of administration.

Q. Are there other benefits to the States of reaching a mutual agreement on the inter-jurisdictional issues that have been the subject of the MSP?

A. Yes. An agreement to the terms of the Revised Protocol by all States will benefit customers through: (1) continued six-State integrated system planning, (2) improved ability to implement the results of system planning efforts, (3) continued access to financial and commercial trading markets by a healthy utility, (4) retention of the benefits and efficiencies of the integrated system, (5) improved ability to work with State policy makers and address differences in policies among our States, and (6) mitigation of the impacts on other jurisdictions of a single State's energy policies.

Q. Has the Company attempted to quantify these benefits?

A. Yes. Although it is difficult to provide a point estimate, there are ranges of impacts that should be considered. For example Mr. Duvall's analytic team produced divisional stand-alone studies that estimated system integration benefits between $200 and $300 million over the fourteen-year study period. Similarly, if PacifiCorp's credit quality was significantly impaired over time as a result of continued disagreement among the States, the potential for increased costs of debt and equity could result. A 100 basis point increase in the Company's cost of equity is equal to an approximate $55 to $60 million increase in total Company revenue requirement. On the commercial and trading side, impairment of credit quality can negatively impact the Company's attractiveness as a counterparty, potentially leading to tighter restrictions or trading limits imposed by other market participants. While we consider these to be extreme possibilities, we remain gravely concerned that a breakdown in the MSP could result in risks and costs to our customers that they would not face if the states are able to agree.

Other Witnesses

Q. What other witnesses are offering Supplemental Testimony?

A. Mr. Duvall's Supplemental Testimony describes various analyses that have been conducted since the original Protocol was filed. In particular, he focuses on:

- The greater understanding that has been gained of the "load growth" issue and how it might be mitigated, and
- The development and calculation of the MC Factor for allocating Mid-Columbia Contracts

Mr. Taylor's Supplemental Testimony provides much of the technical support for the classification and allocation provisions of the Revised Protocol, particularly:

- The details of the embedded cost differential adjustment calculation related to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts;
- Additional detail on the Treatment of Special Contracts; and
- The forecasted State-by-State revenue requirement impacts of the Revised Protocol.

Q. Does this conclude your Supplemental Testimony?

A. Yes.

Exhibit
UP&L__(ALK-1S)

PacifiCorp
Exhibit UP&L__(ALK-1S)
Docket No. 02-035-04
Witness: Andrea L. Kelly

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Testimony of Andrea L. Kelly

Protocol and Appendix A - Definition of Terms

May 2004

I. Introduction

This PacifiCorp Inter-Jurisdictional Cost Allocation Protocol is the result of discussions that have occurred among representatives of PacifiCorp, Commission staff members and other interested parties from Utah, Oregon, Wyoming, Idaho and Washington regarding issues arising from the Company's status as a multi-jurisdictional utility.[1] These discussions were referred to as the "Multi-State Process", or "MSP".

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.

It is in the public interest for PacifiCorp to be able to make long-term Resource commitments with assurance that divergent State policies will not result in it being denied an opportunity to recover its prudently incurred costs. The 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. The assignment or allocation of a particular cost to a State pursuant to the Protocol is not intended to and should not prejudge the prudence of that cost. Nothing in the Protocol shall abridge any State's right and obligation to establish fair, just and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that State. It is the intent that the terms of the Protocol be enduring. However, nothing in the Protocol will negate the

[1] Key staff in California monitored the proceedings and received relevant documents.

necessary flexibility of the regulatory process to deal with changed or unforeseen circumstances.

The Protocol describes how the costs and wholesale revenues 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

Definitions of terms that are capitalized in the Protocol are set forth in Appendix A.

A table identifying the allocation factor to be applied to each component of PacifiCorp's revenue requirement calculation is included as Appendix B.

The algebraic derivation of each allocation factor is contained in Appendix C.

A description and numeric example of how Special Contract Ancillary Service discounts will be reflected in rates is set forth in Appendix D.

A listing of FERC accounts relied upon in the definition of "Annual Embedded Costs" is set forth in Appendix E.

Each State's allocated share of each Mid-Columbia Contract and the method for calculating the shares is set forth in Appendix F.

II. Proposed Effective Date

The Protocol will apply to all PacifiCorp retail rate proceedings initiated subsequent to June 1, 2004.

III. Classification of Resource Costs

All Resource Fixed Costs, Wholesale Contracts and Short-term Purchases and Sales will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All costs associated with Non-Firm Purchases and Sales will be classified as 100 Percent Energy-Related.

IV. Allocation of Resource Costs and Wholesale Revenues

Resources will be assigned to one of four categories for inter-jurisdictional cost allocation purposes:

A. Seasonal Resources,

B. Regional Resources,

C. State Resources, or

D. System Resources.

There are three types of Seasonal Resources, one type of Regional Resources and three types of State Resources. The remainder are System Resources which constitute the substantial majority of PacifiCorp's Resources. Costs associated with each category and type of Resource will be allocated on the following basis:

A. Seasonal Resources

Costs associated with the three types of Seasonal Resources will be assigned and allocated as follows:

1. Simple-Cycle Combustion Turbines (SCCTs): All Fixed Costs associated with SCCTs will be allocated based upon the SSGCT (Seasonal System Generation Combustion Turbine) Factor. All Variable Costs associated with SCCTs will be allocated based upon the SSECT (Seasonal System Energy Combustion Turbine) Factor.
2. Seasonal Contracts: All Costs associated with the Seasonal Contracts will be allocated based upon the SSGP (Seasonal System Generation Purchases) Factor.
3. Cholla IV/ APS: All Fixed Costs associated with the Cholla Unit 4 and the seasonal exchange provided for in the APS Contract will be allocated based upon the SSGCH (Seasonal

System Generation Cholla) Factor. All Variable Costs associated with Cholla Unit 4 and the seasonal exchange provided for in the APS Contract will be allocated based upon the SSECH (Seasonal System Energy Cholla) Factor. Following the expiration of the APS Contract, Cholla Unit 4 will be allocated as a System Resource and no longer allocated as a Seasonal Resource.

B. Regional Resources

Costs associated with Regional Resources will be assigned and allocated as follows:

1. Hydro-Endowment:

A. 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 (Hydro less All Other). The Owned Hydro Embedded Cost Differential Adjustment will be allocated on the DGP factor and the inverse amount will be allocated on the SG factor.

B. Mid-Columbia Contract Embedded Cost Differential Adjustment: The Mid-Columbia Contract Embedded Cost Differential Adjustment is calculated as the Annual Mid-Columbia Contracts Costs, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the Mid-Columbia Contracts (Mid-C less All Other). The allocation of Mid-Columbia Contracts to each State is established pursuant to Appendix F. The Mid-Columbia Embedded Cost Differential Adjustment will be allocated on the MC factor and the inverse amount will be allocated on the SG factor.

C. State Resources

Costs associated with the three types of State Resources will be assigned as follows:

1. Demand-Side Management Programs: Costs associated with Demand-Side Management Programs will be 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 the Load-Based Dynamic Allocation Factors.

2. Portfolio Standards: Costs associated with Resources acquired pursuant to a Portfolio Standard, which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State adopting the standard.

3. Qualifying Facilities (QF) Contracts:

    a. Existing QF Contracts Embedded Cost Differential Adjustment: The Existing QF Contracts Cost Differential Adjustment is calculated as the Annual Existing QF Contracts Costs for each State, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the respective State's Existing QF Contracts (State QF less All Other). The Existing QF Contract Embedded Cost Differential Adjustment will be allocated on a situs basis and the inverse amount will be allocated on the SG factor.

b. New QF Contracts: Costs associated with any New QF Contract, which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State approving such contract.

D. System Resources

All Resources that are not Seasonal Resources or State Resources are System Resources. Generally, all Fixed Costs associated with System Resources and all cost incurred under Wholesale Contracts will be allocated based upon the SG Factor. Generally, all Variable Costs associated with System Resources will be allocated based upon the SE Factor. Revenues received by the Company pursuant to Wholesale Contracts will be allocated based upon the SG Factor. A complete description of the allocation factors to be utilized is set forth in Appendix B.

E. Load Growth

In concert with the current IRP cycle, the Company and parties will analyze and quantify potential cost shifts related to faster-growing States.[2] In addition, a multi-state workgroup will track key factors including actual relative growth rates, forecast relative growth rates, costs of new Resources compared to costs of existing Resources and

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[2] This issue will be monitored through studies that compute the costs allocated to each State for two cases: (a) with currently projected load growth together with a least-cost, least-risk mix of Resource additions to meet that growth and (b) with the fastest-growing State growing at the average growth projected for the remaining States, again with a least-cost, least-risk mix of Resource additions.

other factors deemed relevant to this issue. The Company in consultation with the Standing Committee and parties will file a report with the Commissions regarding this issue, along with one or more options for a structural protection mechanism, no later than nine months after the 2004 IRP is filed.

The MSP Standing Committee is charged with developing one or more mechanisms that could be implemented in a timely manner in the event that the studies show a material and sustained net harm to slower-growing States from the implementation of the IRP with consideration of other mitigating factors such as the addition of Resources to replace lost generation from Hydro-Electric Resources and Mid-Columbia Contracts. Potential mechanisms to be studied include tiered allocations, review of the definition of criteria for Seasonal Resources, a structural separation of the Company, temporary assignment of the costs of some new Resources to fast-growing States, and the inclusion of measures of recent load growth in the computation of allocation factors. In considering such mechanisms, no State will unreasonably withhold its support.

V. Refunctionalization and Allocation of Transmission Costs and Revenues

If the Company is required to refunctionalize assets that are currently functionalized as "transmission" to "distribution", the cost responsibility for any such refunctionalized assets will be assigned to the State where they are located.

Costs associated with transmission assets and firm wheeling expense and revenues will be classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated among the States based upon the SG (System Generation) factor. Non-firm wheeling expense and revenues will be allocated among the States based upon the SE Factor.

VI. Assignment of Distribution Costs

All distribution-related costs that can be directly assigned will be directly assigned to the state where they are located. Distribution costs that cannot be directly assigned will be allocated among States consistent with the factors set forth in Appendix B.

VII. Allocation of Administrative and General Costs

Administrative and general costs, costs of General Plant and costs of Intangible Plant will be allocated among States consistent with the factors set forth in Appendix B.

VIII. Allocation of Special Contract Discounts

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. Revenues received from Special Contract customers, before any discounts for Customer Ancillary Service Attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located. Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources. Costs associated with acquiring Customer Ancillary Services which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State approving such contract. A numeric example of how Special Contract Ancillary Service discounts will be reflected in rates is set forth in Appendix D.

IX. Allocation of Gain or Loss from Sale of Resources or Transmission Assets

Any loss or gain from the sale of a Resource (other than a Freed-Up Resource) or a transmission asset will be allocated among States based upon the allocation factor used to allocate the Fixed Costs of the Resource or the transmission asset at the time of its sale. Each Commission will determine the appropriate allocation of loss or gain allocated to that State as between State customers and PacifiCorp shareholders.

X. Implementation of Direct Access Programs

A. Allocation of Costs and Benefits of Freed-Up Resources

1. Loads lost to Direct Access – Where the Company is required to continue to plan for the load of Direct Access Customers, such load will be included in Load-Based Dynamic Allocation Factors for all Resources. In the State adopting Direct Access, an additional step will take place for ratemaking purposes to establish a value or cost resulting from the departure of the departing load; while other States do not implement the second step.
2. Loads of customers permanently choosing direct access or permanently opting out of New Resources – Where the Company is no longer required to plan for the load of customers who permanently choose direct access or permanently opt out of New Resources, such loads will be included in Load-Based Dynamic

Allocation Factors for all Existing Resources. The loads of customers permanently choosing Direct Access or permanently opting out of New Resources will not be included in Load-Based Dynamic Allocation Factors for New Resources acquired after the Customers' election to permanently choose Direct Access or opt out. An effective date for this process will be established at such time customers permanently choose Direct Access or opt out.

B. Resource Sale Approval

Any proposed sale of a Freed-Up Resource for purposes of calculating transition charges or credits will be subject to applicable regulatory review and approval based upon a "no-harm" standard. States implementing Direct Access Programs that involve the sale of Freed-Up Resources will endeavor to propose a method for allocating the gain or loss on a sale among States in a manner that satisfies the "no-harm" standard in respect to customers in the other States. No Commission will require a sale of Freed-Up Resources to be consummated if the proposed allocation of the gain or loss from the sale among States would cause the Company to distribute more than the total gain on a sale or recover less than the full amount of the total loss on a sale.

C. Allocation of Revenues and Costs from Direct Access Purchases and Sales

Revenues and costs from Direct Access Purchases and Sales will be assigned situs to the State where the Direct Access Customers are located and will not be included in Net Power Costs.

XI. Loss or Increase in Load

Any loss or increase in retail load occurring as a result of condemnation or municipalization, sale or acquisition of new service territory which involves less than five percent of system load, realignment of service territories, changes in economic conditions or gain or loss of large customers will be reflected in changes in Load-Based Dynamic Allocation Factors. The allocation of costs and benefits arising from merger, sale and acquisition transactions proposed by the Company involving more than five percent of system load will be dealt with on a case-by-case basis in the course of Commission approval proceedings.

XII. Commission Regulation of Resources

PacifiCorp shall plan and acquire new Resources on a system-wide least cost, least risk basis. Prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations in each State.

XIII. Sustainability of Protocol

A. Issues of Interpretation

If questions of interpretation of the Protocol arise during rate proceedings and/or audits of results of PacifiCorp's operations, parties will attempt to resolve them with reference to the MSP Legislative History

B. MSP Standing Committee

1. An MSP Standing Committee will be organized consisting of one member of each Commission. The chair of the MSP Standing Committee will be elected each year by the members of the Committee.

2. The MSP Standing Committee will appoint a Standing Neutral, at the Company's expense, to facilitate discussions among States, monitor issues and assist the MSP Standing Committee.

3. At least once during each calendar year, the Standing Neutral will convene a meeting of the MSP Standing Committee and interested parties from all States for the purpose of discussing and monitoring emerging inter-jurisdictional issues facing the Company and its customers. The meetings will be open to all interested parties.

4. The MSP Standing Committee will consider possible amendments to the Protocol that would be equitable to PacifiCorp customers in all States and to the Company. The MSP Standing Committee will have discretion to determine how best to encourage consensual resolution of issues arising under the Protocol. Its actions may include, but will not be limited to: a) appointing a committee of interested parties to study an issue and make recommendations, or b) retaining (at the Company's expense) one or more disinterested parties to make advisory findings on issues of fact arising under the Protocol.

C. Protocol Amendments

Proposed amendments to the Protocol will be submitted by PacifiCorp to each Commission for ratification. The Protocol will only be deemed to have been amended if each of the Commissions who have previously ratified the Protocol ratifies the amendment. PacifiCorp will not seek Commission ratification of any amendment to the Protocol unless and until it has provided interested parties with at least six months advance notice of its intent to do so and endeavored to obtain consensus regarding its proposed amendment. A party's initial support or acceptance of the Protocol will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude that the Protocol no longer produces just and reasonable results. Prior to departing from the terms of the Protocol, consistent with their legal obligations, Commissions and parties will endeavor to cause their concerns to be presented at meetings of the MSP Standing Committee and interested parties from all States in an attempt to achieve consensus on a proposed resolution of those concerns.

Protocol - Appendix A

Defined Terms

For purposes of this Protocol, the following terms will have the following meanings:

"Annual Embedded Costs – All Other" means PacifiCorp's total normalized annual production costs expressed in dollars per MWh (not including costs associated with Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts) as recorded in the FERC Accounts listed in Appendix E to the Protocol.

"Annual Embedded Costs – Hydro-Electric Resources" means PacifiCorp's total normalized annual production costs, expressed in dollars per MWh, associated with Hydro-Electric Resources as recorded in the FERC Accounts listed in Appendix E to the Protocol.

"Annual Mid-Columbia Contract Costs" means annual net costs incurred by PacifiCorp under the Mid-Columbia Contracts, expressed in dollars per MWh.

"APS Contract" means the Long-Term Power Transactions Agreement between PacifiCorp and Arizona Public Service Company dated September 21, 1990, as amended.

"Coincident Peak" means the hour each month that the combined demand of all PacifiCorp retail customers is greatest. In States using an historic test period, Coincident Peak is based upon actual, metered load data. In States using future test periods, Coincident Peak is based upon forecasted loads.

"Company" means PacifiCorp.

"Commission" means a utility regulatory commission in a State.

"Comparable Resource" means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

"Customer Ancillary Service Contracts" means contracts between the Company and a retail customer pursuant to which the Company pays the customer for the right to curtail service so as to lower the costs of operating the Company's system.

"Demand-Related Costs" means capital and other Fixed Costs incurred by the Company in order to be prepared to meet the maximum demand imposed upon its system.

"Demand-Side Management Programs" means programs intended to improve the efficiency of electricity use by PacifiCorp's retail customers.

"Direct Access Customers" means retail electricity consumers located in PacifiCorp's service territory that either: a) purchase electricity directly from a supplier other than PacifiCorp pursuant to a Direct Access Program or b) elect to have all or a portion of the electricity they purchase from PacifiCorp priced based upon market prices rather than the Company's traditional cost-of-service rate.

"Direct Access Program" means a law or regulation that permits retail consumers located in PacifiCorp's service territory to purchase electricity directly from a supplier other than PacifiCorp.

"Direct Access Purchases and Sales" means Wholesale Contracts and Short-Term Purchases and Sales entered into by PacifiCorp either to supply customers who have become Direct Access Customers or to dispose of Freed-Up Resources.

"Energy-Related Costs" means costs, such as fuel costs that vary with the amount of energy delivered by the Company to its customers during any hour plus any portion of Fixed Costs that have been deemed to have been incurred by the Company in order to meet it energy requirements.

"Existing QF Contracts" means Qualifying Facility Contracts entered into prior to May 21, 2004, but not such contracts renewed or extended on or after May 21, 2004.

"Existing Resources" means Resources whose costs were committed to prior to Direct Access Customers making an election to permanently forego being served by the Company at a cost-of-service rate.

"Exchange Contracts" means Wholesale Contracts pursuant to which PacifiCorp accepts delivery of power at one place and/or point in time and delivers power at a different place and/or point in time.

"FERC" means the Federal Energy Regulatory Commission.

"Fixed Costs" means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.

"Freed-Up Resources" means Resources made available to the Company as a result of its customers becoming Direct Access Customers.

"General Plant" means capital investment included in FERC accounts 389 through 399.

"Grant County" means Public Utility District No. 2 of Grant County, Washington

"Hydro-Electric Resources" means Company-owned hydro-electric plants located in Oregon, Washington or California.

"Intangible Plant" means capital investment included in FERC accounts 301 through 303.

"Load-Based Dynamic Allocation Factor" means an allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.

"Mid-Columbia Contracts" means the Power Sales Contract with Grant County dated May 22, 1956; the Power Sales Contract with Grant County dated June 22, 1959; the Priest Rapids Project Product Sales Contract with Grant County dated December 31, 2001; the Additional Products Sales Agreement with Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Grant County dated December 31, 2001; the Power Sales Contract with Douglas County PUD dated September 18, 1963; the Power Sales Contract with Chelan County PUD dated November 14, 1957 and all successor contracts thereto.

"MSP Legislative History" means studies and analyses conducted during the MSP process, testimony offered during proceedings related to Commission ratification of the Protocol and Commission orders ratifying the Protocol.

"Net Power Costs" means PacifiCorp's fuel and wheeling expenses and costs and revenues associated with Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales and Non-Firm Purchases and Sales.

"New QF Contracts" means Qualifying Facility Contracts that are not Existing QF Contracts.

"New Resources" means Resources that are not Existing Resources.

"Non-Firm Purchases and Sales" means transactions at wholesale that are not Wholesale Contracts, Seasonal Contracts, Short-term Purchases or Sales or Direct Access Purchases or Sales.

"Portfolio Standard" means a 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.

"Protocol" means this PacifiCorp Inter-Jurisdictional Cost Allocation Protocol.

"Qualifying Facility Contracts" means contracts to purchase the output of small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.

"Resources" means Company-owned and leased generating plants and mines, Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales and Non-firm Purchases and Sales.

"Short-Term Purchases and Sales" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.

"Simple-Cycle Combustion Turbines" or "SCCTs" means simple-cycle combustion turbine generating units.

"Seasonal Contract" means a Wholesale Contract pursuant to which the Company acquires power for five or less months during more than one year.

"Seasonal Resource" means: (a) a SCCT owned or leased by the Company, (b) any Seasonal Contract or c) Cholla Unit 4.

"Special Contract" means a contract entered between PacifiCorp's and one of its retail customers with prices, term and conditions different from otherwise-applicable tariff rates. Special Contracts may provide for a discount to reflect Customer Ancillary Services Contract attributes.

"Special Contract Ancillary Service Discounts" means discounts from otherwise applicable rates provided for in Special Contracts.

"Standing Neutral" means an independent party, with experience in electric utility ratemaking, retained by the MSP Standing Committee to facilitate discussions among States, monitor issues and assist the MSP Standing Committee as required.

"State Resources" means Resources whose costs are assigned to a single State to accommodate State-specific policy preferences.

"System Resources" means Resources that are not Seasonal Resources, Regional Resources, State Resources or Direct Access Purchases and Sales and whose associated costs and revenues are allocated among all States on a dynamic basis.

"State" means Utah, Oregon, Wyoming, Idaho, Washington or California.

"Variable Costs" means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.

"Wholesale Contracts" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that have a term of one year or longer.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE	)	Docket No. 02-035-04
APPLICATION OF PACIFICORP	)	
FOR AN INVESTIGATION OF	)	SUPPLEMENTAL TESTIMONY
INTER-JURISDICTIONAL	)	OF GREGORY N. DUVALL
ISSUES	)	

MAY 2004

Q. Mr. Duvall, did you previously file testimony in this proceeding?

A. Yes. My Direct Testimony was part of the Company's original filing with the Commission in September of 2003.

Q. What is the purpose of your Supplemental Direct Testimony?

A. The purpose of my Supplemental Direct Testimony is to describe various analyses done by the Company since the September, 2003 Protocol filing, with particular emphasis on studies related to the issue of whether relatively faster growing States inappropriately shift costs to relatively slower growing States. I also sponsor Exhibit UP&L__(GND-1S), which is Appendix F to the Revised Protocol. That Appendix provides details on the calculation of the Mid-Columbia (MC) allocation factor.

Analyses

Q. Why did the Company continue to perform analyses of MSP issues subsequent to the September, 2003 filing?

A. As indicated by Ms. Kelly in her Supplemental Direct Testimony, it was evident that few parties supported the Company's original Protocol proposal for a hydro endowment matched with a "coal endowment". It was also evident that the hydro endowment included in the Modified Accord, known as the fuel adjustment, was no longer acceptable. This is discussed further in Mr. Taylor's Supplemental Direct Testimony. Therefore, we needed to design and test an alternate means of implementing a hydro endowment. The first such substitute tested was the "load decrement method". Mr. Taylor's Supplemental Direct Testimony describes this approach and explains why the Company's analyses of the load decrement method indicated that it was not likely to be workable. The Company's analysis of the fuel adjustment approach and the load decrement approach led us to develop and conduct analyses of the "embedded cost differential method". These analyses did not identify any apparent flaws in the embedded cost differential method and it was, therefore, incorporated into the Revised Protocol.

Q. In your Direct Testimony, you concluded that the "MSP Solution", incorporated in the original Protocol, did not result in a "material" subsidy flowing from slower-growing States to faster growing States. Why did you continue to study the load growth issue after the September, 2003 Protocol filing?

A. For two reasons. First, Oregon parties were not convinced that the analyses done before the September filing were adequate to resolve the load growth issue. Second, the concept of "materiality" is somewhat subjective. Oregon parties pointed out that what appears to be an apparently "small" cost shift, when expressed as a percentage of existing rates, can nonetheless translate into a significant impact when expressed in dollars. Because our September filing did not resolve the load growth issue, parties in Oregon and Utah submitted a number of additional data requests which gave rise to a number of additional studies.

Q. Please describe the nature of these studies.

A. Most of the studies assumed either a one-time increase in Utah loads or a continuing pattern of higher Utah load growth which were matched with different types of Resource additions. Additional similar studies were done assuming higher Oregon load growth and corresponding Resource additions. Furthermore, a study was done which attempted to quantify the cumulative impact of faster Utah load growth over a 14-year period. This study (made in response to DPU 7.3 and OPUC 59 and 60), estimates and compares two different cost streams -- one corresponding to low Utah load growth (equal to the average of the other States' projected load growth) and one corresponding to the higher rate of Utah load growth that is currently forecasted. For purposes of this study, the difference between these cost streams is predictive of the impact on other States of the costs of Utah's additional relative load growth.

Q. What quantitative assumptions underlie these studies?

A. Major assumptions are as follows:

1. All studies use the Company's 2003 load forecast.

2. Additional Resources are layered on top of underlying load growth and planned IRP Resource additions.

3. All studies assume an underlying system peak Resource deficiency in the early years and the addition of Resources that closely match the Diversified Portfolio I from the Company's 2003 Integrated Resource Plan with two long-term purchased power contracts removed from the west control area to reflect the lower loads forecast for the west in the Company's 2003 load forecast.

4. Most of the studies assume that future wholesale gas and electricity prices will follow the Company's forward price curves. Some of the studies were done with a high natural gas/electricity price assumption.

Q. Please summarize the results of these studies.

A. Under a rolled-in allocation method, a faster-growing State supports both its allocated share of any new Resource additions and a larger share of the Company's existing costs. Correspondingly, slower growing States support their allocated share of the cost of the New Resource addition, but a smaller share of the Company's existing costs. In our studies, the sum of these two State revenue requirement impacts is compared to the total revenue requirement impact of the new Resource additions. If the total revenue requirement increase experienced by a faster-growing State is equal to or greater than the total revenue requirement impact of a new Resource, the faster growing State is deemed to be "supporting the cost of its load growth" and not causing a cost shift to slower growing States.

When considered from this perspective, our studies suggest that under the various approaches, a rolled-in allocation method, as embodied in the Revised Protocol, results in the growth State supporting between 86 percent and 127 percent of the cost of its load growth.

Q. Why do the percentages differ from study to study?

A. It appears that principal drivers of the study outcomes are:

1. The greater the rate of growth of one State compared to other States, the greater is the potential for cost shifts to slower growing States.

2. The higher the cost of new Resource additions compared to existing Resources, the greater is the potential for cost shifts to slower growing States.

3. The better New Resource additions are matched to load patterns through an effective IRP process, the lower is the potential for cost shifts to slower growing States.

Q. Do these study results suggest that parties should ignore the potential for faster growing States shifting costs to slower growing States?

A. No. The studies indicate that there is a potential for some shifting of costs. As a general proposition, MSP participants seem to favor eliminating any potential cost shift, as long as that could be done in a relatively simple and understandable way without giving rise to other, undesirable unintended consequences.

Q. Are there other mitigating factors to consider?

A. Yes. When a State loses load unexpectedly, other states are automatically allocated a greater share of the fixed and variable costs of all Resources. This helps to mitigate the impact on the remaining customers in the State that loses load who would otherwise bear a larger share of the fixed and variable costs.

In addition, the impact of Utah load growth is mitigated by the expected Resource loss in western States. One of the underlying tenets of the Revised Protocol is that all States bear a rolled-in share of resources that are acquired to replace existing Resources. Existing Resources that will require replacement over the next several years include expiring long-term wholesale contracts (primarily on the west side of the system), plant retirements and the lost generation from Hydro-Electric Resources and Mid-Columbia Contracts as a result of relicensing and contract renegotiation. For the States that are recipients of the Hydro Endowment, this means that other States are paying a share of the costs of replacing resources from which the Hydro Endowment states have benefited.

Q. Has an acceptable method of eliminating any potential for cost shifts been identified?

A. No. However, as indicated by Ms. Kelly, the Company and other parties have committed to further discussions and analysis of potential additional allocation mechanisms or structural changes that would better address the issue.

Development of the MC Factor

Q. What is contained in Exhibit UP&L__(GND-1S)?

A. Exhibit UP&L__(GND-1S) is Appendix F to the Revised Protocol and contains a description of the calculation of the MC factor as well as example calculations of the factor. The MC factor is used in the Revised Protocol to allocate the Mid-Columbia Adjustment among the States.

Q. Why has the Company developed an MC factor?

A. The Company performed an extensive review of the Mid-Columbia Contracts at the request of the MSP participants. There are four contracts that were entered into in the 1950's and 1960's, and three contracts that were entered into in 2001. These latter three contracts are successor contracts to the two earlier contracts with Grant County which provide the Company a share of the output of the Priest Rapids and Wanapum dams. The Priest Rapids contract stated that the output was for the benefit of Oregon customers and the Wanapum contract stated that the output was for the benefit of Oregon and Washington customers. Based on this language, the MC factor is developed as though the Priest Rapids energy is assigned to Oregon and the Wanapum energy is assigned to Oregon and Washington as described in Appendix F. The energy from the three successor contracts is assigned to Oregon during the time subsequent to the expiration of the Priest Rapids contract and prior to the expiration of the Wanapum contract. After both contracts have expired, the energy from the successor contracts is split between Oregon and Washington as described in Appendix F. In the MC factor, the energy from the remaining two contracts, associated with the Rocky Reach and Wells projects, is spread system-wide as these two contracts do not have specific language identifying any particular State as the beneficiary of the output. The MC factor is then calculated by dividing the energy assigned and allocated to each State by the total energy from the Mid-Columbia Contracts. The Mid-Columbia Adjustment is then made based on an allocated share of the costs of all of the Mid-Columbia Contracts using the MC factor. This adjustment ensures that no one State is burdened if the costs under one of the Mid-Columbia Contracts diverge from the other contracts. This method ensures that all States are afforded a share of the costs and benefits of the Mid-Columbia Contracts, with Oregon and Washington receiving a larger share than would be the case of they were treated as System Resources.

Q. Does that conclude your Supplemental Direct Testimony?

A. Yes.

PacifiCorp
Exhibit UP&L__(GND-1S)
Docket No. 03-035-04
Witness: Greg N. Duvall

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Greg N. Duvall

Appendix F – Methodology for Determining Mid-C (MC) Factor

May 2004

Protocol Appendix F
Methodology for Determining Mid-C (MC) Factor

Energy for each Mid-C contract is allocated as follows to determine the MC factor.

- Priest Rapids energy is assigned 100% to Oregon.
- Rocky Reach energy is allocated on the SG factor.
- Wanapum energy is assigned to Oregon and Washington based upon each state's respective share of the SG factor.
  - Wanapum energy assigned to Oregon = Oregon SG / (total Oregon and Washington SG).
  - Wanapum energy assigned to Washington = Washington SG / (total Oregon and Washington SG).
- Wells energy is allocated on the SG factor.
- The Grant replacement contracts begin at the time the Priest Rapids contract terminates. The energy from these contracts is assigned to Oregon through October 31, 2009.
- Effective November 1, 2009, the date the Wanapum contract expires, the Grant replacement contract energy is divided into two pieces based on PacifiCorp's share of the nameplate of Priest Rapids and Wanapum as shown in the following calculation:

	Nameplate Capacity Mw	PacifiCorp's Share - %	PacifiCorp's Share of Nameplate - Mw	PacifiCorp's % share of nameplate
Priest Rapids	789	13.9%	110	41.35%
Wanapum	831	18.7%	155	58.65%
	1,620		265	100.00%

- The Priest Rapids portion of the Grant County replacement contracts is 41.35%. The energy associated with the Grant County replacement contracts for Priest Rapids is assigned 100% to Oregon.
- The Wanapum portion of the Grant County replacement contracts is 58.65%. The energy associated with the Grant County replacement contracts for Wanapum is assigned to Washington based on the ratio of the Washington SG factor to the sum of the Oregon and Washington SG factors. The remaining energy from the Wanapum portion is assigned to Oregon.

After all of the energy from the Mid-Columbia Contracts has been assigned or allocated to each State, then the MC factor is created by dividing each State's energy by the total energy associated with the Mid-Columbia Contracts. The MC factor is used to allocate the Mid-Columbia Contract embedded cost differential to each State.

Protocol Appendix F

Factors Used to Allocate Mid C Energy to Jurisdictions

2005 — Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.80%		1.80%		
Oregon	100.00%	28.86%	76.94%	28.86%	100.00%	76.94%
Washington		8.65%	23.06%	8.65%	0.00%	23.06%
Utah		41.93%		41.93%		
Idaho		5.85%		5.85%		
Wyoming		12.91%		12.91%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2007 — Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.73%		1.73%		
Oregon	100.00%	27.56%	76.68%	27.56%	100.00%	76.68%
Washington		8.38%	23.32%	8.38%	0.00%	23.32%
Utah		44.13%		44.13%		
Idaho		5.59%		5.59%		
Wyoming		12.61%		12.61%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2011 — Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.65%		1.65%		
Oregon	100.00%	26.13%	76.18%	26.13%	100.00%	76.18%
Washington		8.17%	23.82%	8.17%	0.00%	23.82%
Utah		46.96%		46.96%		
Idaho		5.20%		5.20%		
Wyoming		11.90%		11.90%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Calculation of Mid C Factor

2005 — MWH

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,658		4,749			10,407	0.54%
Oregon	567,559	90,829	596,498	76,238	-	-	1,331,125	69.27%
Washington		27,222	178,772	22,849			228,842	11.91%
Utah		131,984		110,783			242,767	12.63%
Idaho		18,426		15,466			33,892	1.76%
Wyoming		40,636		34,108			74,744	3.89%
	567,559	314,754	775,270	264,193	-	-	1,921,777	100.00%

2007 — MWH

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,457		4,581			10,038	0.52%
Oregon	-	86,746	594,444	72,811	564,683	-	1,318,684	68.72%
Washington		26,388	180,826	22,149			229,363	11.95%
Utah		138,899		116,587			255,486	13.31%
Idaho		17,582		14,758			32,340	1.69%
Wyoming		39,682		33,308			72,990	3.80%
	-	314,754	775,270	264,193	564,683	-	1,918,900	100.00%

2011 — MWH

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,200		4,365			9,565	0.65%
Oregon	-	82,231	-	69,021	372,327	402,325	925,904	62.59%
Washington		25,708	-	21,579	-	125,776	173,064	11.70%
Utah		147,810		124,066			271,876	18.38%
Idaho		16,353		13,726			30,079	2.03%
Wyoming		37,452		31,436			68,887	4.66%
	-	314,754	-	264,193	372,327	528,101	1,479,375	100.00%

(1) Priest Rapids Power Sales Agreement with Grant County dated May 2, 1956
(2) Rocky Reach Power Sales Agreement with Chelan County dated November 14, 1957
(3) Wanapum Power Sales Agreement with Grant County dated June 22, 1959
(4) Wells Power Sales Agreement with Douglas County dated September 18, 1963
(5) Priest Rapids Project Product Sales Agreement with Grant County dated December 31, 2001
The Additional Product Sales Agreement with Grant County dated December 31, 2001
The Priest Rapids Reasonable Portion Power Sales Agreement with Grant County dated December 31, 2001

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN INVESTIGATION OF INTER-JURISDICTIONAL ISSUES	)))))	Docket No. 02-035-04 SUPPLEMENTAL TESTIMONY OF DAVID L. TAYLOR

MAY 2004

Q. Are you the same David L. Taylor who offered Direct Testimony in this proceeding?

A. Yes.

Purpose

Q. What is the purpose of your Supplemental Testimony in these proceedings?

A. My Supplemental Testimony discusses and supports changes to the PacifiCorp Inter-Jurisdictional Cost Allocation Protocol ("Protocol") contained in Exhibit UP&L__(ALK-1S). As in my Direct Testimony, when I capitalize terms in my Supplemental Testimony, those terms have the same meaning as provided for in Appendix A to the Revised Protocol contained in Exhibit UP&L__(ALK-1S).

Specifically, my Supplemental Testimony focuses on the following key areas:

- Proposed changes to classification of SCCTs,
- Proposed changes to the allocation of Regional Resources,
- Proposed allocation of Existing QF Contracts,
- Proposed elimination of Protocol language related to the allocation of transmission costs,
- Clarification and detail on the treatment of Special Contracts, and
- Estimates of the revised Protocol's impact on the revenue requirements of each State.

Cost Allocation Appendices

Q. Have you prepared Exhibits that identify how all cost components of the revenue requirement are allocated among States under the Revised Protocol?

A. Yes. Exhibit UP&L__(DLT-1S), which is Appendix B of the Revised Protocol, identifies the allocation factor applied to each component of the revenue requirement calculation. Exhibit UP&L__(DLT-2S), which is Appendix C of the Revised Protocol, gives a detailed explanation and the algebraic formula for each allocation factor. Exhibit UP&L__(DLT-3S), which is Appendix D of the Revised Protocol, provides a description and numerical examples of the proposed treatment of Special Contracts. I will discuss this in detail later in my testimony. Exhibit UP&L__(DLT-4S), which is Appendix E of the Revised Protocol, provides the methodology for calculating the Annual Embedded Cost that I also discuss later in my testimony.

Classification of Simple-Cycle Combustion Turbine Fixed Costs

Q. In your direct testimony, PacifiCorp proposed to classify the fixed costs of SCCTs differently from the remainder of the Company's Resources. Has the Company reconsidered this proposal?

A. Yes. The Company now proposes to classify the Fixed Costs of SCCTs on the same basis as all other Resources. Although SCCTs are generally designed and operated to run during peak-load periods, rather than to produce sustained, low cost energy, we have been persuaded that there are valid reasons to continue past allocation practices that classify the Fixed Costs of all Resources as 75 percent Demand-Related and 25 percent Energy-Related.

Q. What are those reasons?

A. First, as discussed in my Direct Testimony, a wide range of demand and energy classification methods could be supported on a technical basis. Given the diversity of PacifiCorp's Resource portfolio, it has been argued that certain Resources should be classified more heavily to Demand-Related and that certain Resources should be classified more heavily to Energy-Related. The classification of all Resources as 75 percent Demand-Related and 25 percent Energy-Related appears to fairly recognize this balance. To single out one type of Resource – SCCTs – for special treatment could upset the balance and lead to unnecessary complexity and ambiguity for classification of all Resources.

Second, the proposed change recognizes that the operation of Resources on a year-to-year basis varies due to load and market factors and may be different from the expected operation when the Resources were acquired. Finally, the Company agrees with several parties that, absent a compelling reason to change, minimizing changes from current allocation practices will aid in implementation of the Protocol and limit cost shifts among States.

Q. Does the Company propose to eliminate the Seasonal Resource designation for allocation of SCCTs and include them as part of System Resources?

A. No. SCCTs will continue to be treated as Seasonal Resources with their costs allocated using seasonal allocation factors as described in my Direct Testimony.

Cost Allocation for Regional Resources

Q. What changes is the Company proposing to the allocation of Regional Resources?

A. As discussed in Ms. Kelly's testimony, the Company proposes to eliminate the coal endowment and to eliminate the ability for Oregon to opt out of the First Major New Coal Resource. In addition, the Company proposes a change to the allocation of costs related to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

Hydro-Electric Resources and Mid-Columbia Contracts

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 operating costs of Hydro-Electric Resources are, in the first instance, 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 and the reciprocal amount (All Other less Hydro) will be allocated 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. In the future, the adjustment is forecasted to become positive (the Hydro-Electric Resource costs are more expensive than all other Resources). At that time the adjustment would be a net cost to the former Pacific Power jurisdictions and a credit to the other jurisdictions.

Mid-Columbia Contracts and Existing QF 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, in the first instance, 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 Supplemental Direct Testimony.

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 Mid-Columbia Contracts are, in the first instance, 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.

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, Exhibit UP&L__(DLT-4S).

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.

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 proposal to combine the Hydro Endowment with a Coal Endowment, as described in your direct testimony?

A. It did not enjoy support from MSP participants.

Q. Please describe the existing "fuel adjustment mechanism".

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

- 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 MWHs 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 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 bear a proportionate share of post Utah/Pacific merger Hydro-Electric Resource capital costs, but only former Pacific Power States 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.

Transmission Costs

Q. How has the Company revised the Protocol in respect to the classification and allocation of transmission costs?

A. In its initial proposal, PacifiCorp included an allocation provision that would have applied should Commissions approve its participation in a Regional Transmission Organization ("RTO"). The proposal was simply to allocate charges from the RTO among the States based upon the same billing determinants relied upon by the FERC in setting the RTO's rates. Several parties expressed concern that this proposal was premature given the evolving regional RTO discussions and requested that the provision be eliminated. The Company has complied with those requests and removed that provision.

Special Contracts

Q. Has the Company modified its proposal regarding the treatment of Special Contracts?

A. No. However Appendix D, Exhibit UP&L__(DLT-3S), has been added to the Protocol for greater clarity. Appendix D identifies two general types of Special Contracts: 1) Special Contracts without Customer Ancillary Service Contract attributes and 2) 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. Let me explain the difference.

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 will be included in all Load-Based Dynamic Allocation Factors. When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's 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. A numeric example of the regulatory treatment of Special Contracts without Ancillary Service Contract attributed is shown in Appendix D, Table 1.

For allocation purposes Special Contracts with Customer Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the ancillary service contract rate. Loads associated with the retail service to the Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. The Customer Ancillary Service Contract attributes of the Special Contract are viewed, not as a reduction in load, but rather as the acquisition of Resources to meet Company load. Therefore, when interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur. Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service Contract attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located. Because discounts from tariff prices provided for in Special Contracts or payments to retail customers, that recognize the Customer Ancillary Service Contract attributes of the Contract are considered as payments for Resource acquisitions, they will be allocated among States on the same basis as System Resources. A numeric example of the regulatory treatment of Special Contracts with Customer Ancillary Service Contract attributes is shown in Appendix D, Table 2.

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be 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 UP&L__(DLT-5S), presents estimates of impacts on each State's revenue requirement. 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 MSP Solution is higher and a negative percent indicates the revenue requirement under the MSP Solution 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 MSP Solution.

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. The calculations do not include the potential State-by-State revenue requirement impacts of New QF Contracts, Special Contracts and Portfolio Resources.

Q. What do you conclude from Exhibit UP&L__(DLT-5S)?

A. I conclude that the revenue requirement impacts 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.

Q. Does this conclude your Supplemental Testimony?

A. Yes.

PacifiCorp
Exhibit UP&L__(DLT-1S)
Docket No. 02-035-04
Witness: David L. Taylor

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Testimony of David L. Taylor

Appendix B – Allocation Factor Applied to each Component of Revenue Requirement

May 2004

Protocol Appendix B
Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Sales to Ultimate Customers			
440	Residential Sales		
		Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales		
		Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting		
		Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority		
		Direct assigned - Jurisdiction	S
448	Interdepartmental		
		Direct assigned - Jurisdiction	S
447	Sales for Resale		
		Direct assigned - Jurisdiction	S
		Non-Firm	SE
		Firm	SG
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
			SG
Other Electric Operating Revenues			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S
451	Misc Electric Revenue		
		Direct assigned - Jurisdiction	S
		Other - Common	SO
454	Rent of Electric Property		
		Direct assigned - Jurisdiction	S
		Common	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
456	Other Electric Revenue		
		Direct assigned - Jurisdiction	S
		Wheeling Non-firm, Other	SE
		Common	SO
		Wheeling - Firm, Other	SG
Miscellaneous Revenues			
41160	Gain on Sale of Utility Plant - CR		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
41170	Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
4118	Gain from Emission Allowances		
		SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits		
		NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
Miscellaneous Expenses			
4311	Interest on Customer Deposits		
		Utah Customer Service Deposits	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Steam Power Generation			
500, 502, 504-514	Operation Supervision & Engineering		
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
501	Fuel Related		
		Remaining steam plants	SE
		Peaking Plants	SSECT
		Cholla	SSECH
503	Steam From Other Sources		
		Steam Royalties	SE
Nuclear Power Generation			
517 - 532	Nuclear Power O&M		
		Nuclear Plants	SG
Hydraulic Power Generation			
535 - 545	Hydro O&M		
		Pacific Hydro	SG
		East Hydro	SG
Other Power Generation			
546, 548-554	Operation Super & Engineering		
		Other Production Plant	SG
547	Fuel		
		Other Fuel Expense	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Other Power Supply			
555	Purchased Power		
		Direct assigned - Jurisdiction	S
		Firm	SG
		Non-firm	SE
		100 MW Hydro Extension	SG
		Peaking Contracts	SSGC
556 - 557	System Control & Load Dispatch		
		Other Expenses	SG
	Embedded Cost Differential Endowments		
		Company Owned Hydro Embedded Cost Differential (Hydro less All Other)	DGP
		Company Owned Hydro Embedded Cost Differential (All Other less Hydro)	SG
		Mid-Columbia Contract Embedded Cost Differential (Mid C less All Other)	MC
		Mid-Columbia Contract Embedded Cost Differential (All Other less Mid C)	SG
		Existing QF Contracts Embedded Cost Differential (QF less- All Other)	S
		Existing QF Contracts Embedded Cost Differential (All Other less QF)	SG
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
403NP	Nuclear Depreciation		
		Nuclear Plant	SG
403HP	Hydro Depreciation		
		Pacific Hydro	SG
		East Hydro	SG
403OP	Other Production Depreciation		
		Other Production Plant	SG
403TP	Transmission Depreciation		
		Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction		
		Land & Land Rights	S
		Structures	S
		Station Equipment	S
		Poles & Towers	S
		OH Conductors	S
		UG Conduit	S
		UG Conductor	S
		Line Trans	S
		Services	S
		Meters	S
		Inst Cust Prem	S
		Leased Property	S
		Street Lighting	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
403GP	General Depreciation		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
403MP	Mining Depreciation		
		Remaining Mining Plant	SE
AMORTIZATION EXPENSE			
404GP	Amort of LT Plant - Capital Lease Gen		
		Direct assigned - Jurisdiction	S
		General	SO
		Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam		
		Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant		
		Distribution	S
		Production, Transmission	SG
		General	SO
		Mining Plant	SE
		Customer Related	CN
404MP	Amort of LT Plant - Mining Plant		
		Mining Plant	SE
404HP	Amortization of Other Electric Plant		
		Pacific Hydro	SG
		East Hydro	SG
405	Amortization of Other Electric Plant		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
406	Amortization of Plant Acquisition Adj		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
407	Amort of Prop Losses, Unrec Plant, etc		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Trojan	TROJP
Taxes Other Than Income			
408	Taxes Other Than Income		
		Direct assigned - Jurisdiction	S
		Property	GPS
		General Payroll Taxes	SO
		Misc Energy	SE
		Misc Production	SG
DEFERRED ITC			
41140	Deferred Investment Tax Credit - Fed		
		ITC	DGU
41141	Deferred Investment Tax Credit - Idaho		
		ITC	DGU
Interest Expense			
427	Interest on Long-Term Debt		
		Direct assigned - Jurisdiction	S
		Interest Expense	SNP
428	Amortization of Debt Disc & Exp		
		Interest Expense	SNP
429	Amortization of Premium on Debt		
		Interest Expense	SNP
431	Other Interest Expense		
		Interest Expense	SNP
432	AFUDC - Borrowed		
		AFUDC	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
Interest & Dividends			
419	Interest & Dividends		
		Interest & Dividends	SNP
DEFERRED INCOME TAXES			
41010	Deferred Income Tax - Federal-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE
41011	Deferred Income Tax - State-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE
41110	Deferred Income Tax - Federal-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Mining related	SE
		General	SO
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJP
		Pacific Hydro	SG
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	SG
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO
SCHMDT	Deductions - Temporary		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Miscellaneous	SNP
		Pacific Hydro	SG
		Mining related	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	TAXDEPR
		Distribution	SNPD
State Income Taxes			
40911	State Income Taxes		
		Income Before Taxes	IBT
40910		FIT True-up	S
40910		Wyoming Wind Tax Credit	SG
Steam Production Plant			
310 - 316			
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
Nuclear Production Plant			
320-325			
		Nuclear Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
Hydraulic Plant		
330-336		
	Pacific Hydro	SG
	East Hydro	SG
Other Production Plant		
340-346		
	Other Production Plant	SG
TRANSMISSION PLANT		
350-359		
	Transmission Plant	SG
DISTRIBUTION PLANT		
360-373		
	Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
GENERAL PLANT			
389 - 398			
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
399	Coal Mine		
		Remaining Mining Plant	SE
399L	WIDCO Capital Lease		
		WIDCO Capital Lease	SE
1011390	General Capital Leases		
		Direct assigned - Jurisdiction	S
		General	SO
GP	Unclassified Gen Plant - Acct 300		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
INTANGIBLE PLANT			
301	Organization		
		Direct assigned - Jurisdiction	S
302	Franchise & Consent		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
303	Miscellaneous Intangible Plant		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General	SO
303	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Rate Base Additions			
105	Plant Held For Future Use		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining Plant	SE
114	Electric Plant Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
120	Nuclear Fuel		
		Nuclear Fuel	SE
124	Weatherization		
		Direct assigned - Jurisdiction	S
		General	SO
182W	Weatherization		
		Direct assigned - Jurisdiction	S
186W	Weatherization		
		Direct assigned - Jurisdiction	S
151	Fuel Stock		
		Steam Production Plant	SE
152	Fuel Stock - Undistributed		
		Steam Production Plant	SE
25316	DG&T Working Capital Deposit		
		Mining Plant	SE
25317	DG&T Working Capital Deposit		
		Mining Plant	SE
25319	Provo Working Capital Deposit		
		Mining Plant	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
154	Materials and Supplies		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production - Common	SNPPS
		Hydro	SNPPH
		Distribution	SNPD
			SG
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SNPPS
165	Prepayments		
		Direct assigned - Jurisdiction	S
		Property Tax	GPS
		Production, Transmission	SG
		Mining	SE
		General	SO
182M	Misc Regulatory Assets		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Cholla Transaction Costs	SSGCH
		Mining	SE
		General	SO
186M	Misc Deferred Debits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
		Production - Common	SNPPS

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Working Capital			
CWC	Cash Working Capital		
		Direct assigned - Jurisdiction	S
OWC		Other Working Capital	
131		Cash	SNP
135		Working Funds	SG
143		Other Accounts Receivable	SO
232		Accounts Payable	SO
232		Accounts Payable	SE
253		Deferred Hedge	SE
25330		Other Deferred Credits - Misc	SE
Miscellaneous Rate Base			
18221	Unrec Plant & Reg Study Costs		
		Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
141	Impact Housing - Notes Receivable		
		Employee Loans - Hunter Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Rate Base Deductions			
235	Customer Service Deposits		
		Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance		SO
2282	Prov for Injuries & Damages		SO
2283	Prov for Pensions and Benefits		SO
22841	Accum Misc Oper Prov-Black Lung		
		Mining	SE
22842	Accum Misc Oper Prov-Trojan		
		Trojan Plant	TROJD
252	Customer Advances for Construction		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Customer Related	CN
25399	Other Deferred Credits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
190	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
281	Accumulated Deferred Income Taxes		
		Production, Transmission	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
282	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
283	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
255	Accumulated Investment Tax Credit		
		Direct assigned - Jurisdiction	S
		Investment Tax Credits	ITC84
		Investment Tax Credits	ITC85
		Investment Tax Credits	ITC86
		Investment Tax Credits	ITC88
		Investment Tax Credits	ITC89
		Investment Tax Credits	ITC90
		Investment Tax Credits	DGU

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
PRODUCTION PLANT ACCUM DEPRECIATION			
108SP	Steam Prod Plant Accumulated Depr		
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
108NP	Nuclear Prod Plant Accumulated Depr		
		Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr		
		Pacific Hydro	SG
		East Hydro	SG
108OP	Other Production Plant - Accum Depr		
		Other Production Plant	SG
TRANS PLANT ACCUM DEPR			
108TP	Transmission Plant Accumulated Depr		
		Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR			
108360 - 108373	Distribution Plant Accumulated Depr		
		Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR			
108GP	General Plant Accumulated Depr		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
108MP	Mining Plant Accumulated Depr.		
		Mining Plant	SE
108MP	Less Centralia Situs Depreciation		
		Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease		
		General	SO
1081399	Accum Depr - Capital Lease		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
ACCUM PROVISION FOR AMORTIZATION			
111SP	Accum Prov for Amort-Steam		
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
111GP	Accum Prov for Amort-General		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSGCT
		Cholla	SSGCH
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
111HP	Accum Prov for Amort-Hydro		
		Pacific Hydro	SG
		East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		Production, Transmission	SG
		General	SO
		Mining	SE
		Customer Related	CN
111IP	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining		
		Mining Plant	SE

Exhibit
UP&L__(DLT-2S)

PacifiCorp
Exhibit UP&L__(DLT-2S)
Docket No. 02-035-04
Witness: David L. Taylor

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Testimony of David L. Taylor

Appendix C – Allocation Factor – Algebraic Definitions

May 2004

Protocol Appendix C
Allocation Factors
Algebraic Definitions
May 20, 2004

Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor definitions:

It is assumed that the 12CP (j=1 to 12) method is used in defining the System Capacity.

It is assumed that twelve months (j=1 to 12) method is used in defining the System Energy.

In defining the System Generation Factor, the weighting of 75% System Capacity, 25% System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor (SC)

$$SCi=\frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i	=	**System Capacity Factor** for jurisdiction i.
TAP_{ij}	=	Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

System Energy Factor (SE)

$$SEi = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i = **System Energy Factor** for jurisdiction i.

$TAEi_j$ = Temperature Adjusted Input Energy of jurisdiction i in month j.

Division Energy - Pacific Factor (DEP)

$$DEP_i = \frac{SE_i^*}{\sum_{i=1}^{i=8} SE_i^*}$$

where:

DEP_i = **Division Energy - Pacific Factor** for jurisdiction i.

$SE_i^* = SE_i$ if i is a Pacific jurisdiction, otherwise

$SE_i^* = 0.$

SE_i = System Energy for jurisdiction i.

Division Energy - Utah Factor (DEU)

$$DEU_i = \frac{SE_i^*}{\sum_{i=1}^{i=8} SE_i^*}$$

where:

DEU_i = **Division Energy - Utah Factor** for jurisdiction i.

$SE_i^* = SE_i$ if i is a Utah jurisdiction, otherwise

$SE_i^* = 0.$

SE_i = System Energy for jurisdiction i.

System Generation Factor (SG)

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

SG_i	=	**System Generation Factor** for jurisdiction i.
SC_i	=	System Capacity for jurisdiction i.
SE_i	=	System Energy for jurisdiction i.

Seasonal System Generation Combustion Turbine (SSGCT)

$$SSGCTi = \left(\frac{\sum_{j=1}^{12} WMO_{jct} * TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jct} * TAP_{ij}}\right) * .75 + \left(\frac{\sum_{j=1}^{12} WMO_{jct} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jct} * TAE_{ij}}\right) * .25$$

where:

$SSGCTi$ = **Seasonal System Generation Combustion Turbine Factor** for jurisdiction i.

$$WMO_{jCT} = \frac{\sum_{ct=1}^{n} E_{jct}}{\sum_{j=1}^{12}\sum_{ct=1}^{n} E_{jct}}$$ Weighted monthly energy generation of combustion turbine

where:

E_{jct} = Monthly Energy generation of combustion turbine ct in month j.

n = Number of combustion turbines

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction i in month j.

<u>Seasonal System Energy Combustion Turbine (SSECT)</u>

$$SSECTi = \frac{\sum_{j=1}^{12} WMO_{jct} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jct} * TAE_{ij}}$$

where:

$SSECTi$ = **Seasonal System Energy Combustion Turbine Factor** for jurisdiction i.

$WMO_{jCT} = \dfrac{\sum_{ct=1}^{n} E_{jct}}{\sum_{j=1}^{12}\sum_{ct=1}^{n} E_{jct}}$ Weighted monthly energy generation of combustion turbine

where:

E_{jct} = Monthly Energy generation of combustion turbine ct in month j.

n = Number of combustion turbines

TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction i in month j.

Seasonal System Generation Purchases (SSGP)

$$SSGPi = \left(\frac{\sum_{j=1}^{12} WMO_{jsp} * TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jsp} * TAP_{ij}} \right) * .75 + \left(\frac{\sum_{j=1}^{12} WMO_{jsp} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jsp} * TAE_{ij}} \right) * .25$$

where:

$SSGPi$ = **Seasonal System Generation Purchases Factor** for jurisdiction i.

$$WMO_{jSP} = \frac{\sum_{sp=1}^{n} E_{jsp}}{\sum_{j=1}^{12}\sum_{sp=1}^{n} E_{jsp}}$$ Weighted monthly energy from seasonal purchases

where:

E_{jsp} = Monthly Energy from seasonal purchases sp in month j.
n = Number of seasonal purchases

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction i in month j.

<u>Seasonal System Generation Cholla (SSGCH)</u>

$$SSGCHi = \left(\frac{\sum_{j=1}^{12} WMO_{jch} * TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jch} * TAP_{ij}} \right) * .75 + \left(\frac{\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}} \right) * .25$$

where:

$SSGCHi$ = **Seasonal System Generation Cholla Factor** for jurisdiction i.

$$WMO_{jCH} = \frac{E_{jch} + E_{jraps} - E_{jdaps}}{\sum_{j=1}^{12} E_{jch} + E_{jraps} - E_{jdaps}}$$ Weighted monthly energy generation of Cholla plus energy received from APS less energy delivered to APS

where:

E_{jch} = Monthly Energy generation of Cholla plant in month j.
E_{jraps} = Monthly Energy received from APS in month j.
E_{jdaps} = Monthly Energy delivered to APS in month j.

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

TAE_{ij} = Temperature Adjusted Energy Output of jurisdiction i in month j.

Seasonal System Energy Cholla (SSECH)

$$SSECHi = \frac{\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}}$$

where:

$SSECHi$ = **Seasonal System Energy Cholla Factor** for jurisdiction i.

$$WMO_{jCH} = \frac{E_{jch} + E_{jraps} - E_{jdaps}}{\sum_{j=1}^{12} E_{jch} + E_{jraps} - E_{jdaps}}$$

Weighted monthly energy generation of Cholla plus energy received from APS less energy delivered to APS

where:

E_{jch} = Monthly Energy generation of Cholla plant in month j.
E_{jraps} = Monthly Energy received from APS in month j.
E_{jdaps} = Monthly Energy delivered to APS in month j.

TAE_{ij} = Temperature Adjusted Energy Output of jurisdiction i in month j.

<u>Mid-C (MC)</u>

$$MC_i = \frac{WMCE_i}{\sum_{i=1}^{i=8} WMCE_i}$$

where:

MCi = **Mid-C Factor** for jurisdiction i.

$WMCE_i$ = $E^*_{ipr} + (E_{rr} * SGi) + (E_{wa} * WWA_i) + (E_w * SGi)$ Weighted Mid-C Contracts annual energy generation

where:

$E^*_{ipr} = E_{ipr}$ If i is Oregon, otherwise

$E^*_{ipr} = 0$

E_{ipr} = Annual Energy generation of Priest Rapids.

E_{rr} = Annual Energy generation of Rocky Reach.

E_{wa} = Annual Energy generation of Wanapum.

E_w = Annual Energy generation of Wells.

$WWA_i = \frac{SG^*_i}{\sum_{i=1}^{i=8} SG^*_i}$ Weighted Wanapum Energy

where:

$SG^*_i = SG_i$ if i is Washington or Oregon jurisdiction, otherwise

$SG^*_i = 0.$

SG_i = System Generation for jurisdiction i.

Division Generation - Pacific Factor (DGP)

$$DGP_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGP_i = **Division Generation - Pacific Factor** for jurisdiction i.
SG_i^* = SG_i if i is a Pacific jurisdiction, otherwise
$SG_i^* = 0$.
SG_i = System Generation for jurisdiction i.

Division Generation - Utah Factor (DGU)

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.
SG_i^* = SG_i if i is a Utah jurisdiction, otherwise
$SG_i^* = 0$.
SG_i = System Generation for jurisdiction i.

System Net Plant Production - Steam Factor (SNPPS)

$$SNPPS_i = \frac{SG_i * (PPSO - ADPPSO) + SSGCT_i * (PPSCT - ADPPSCT) + SSGCH_i * (PPSCH - ADPPSCH)}{(PPS - ADPPS)}$$

where:

$SNPPS_i$	=	**System Net Plant - Steam Factor** for jurisdiction i.
SG_i	=	System Generation for jurisdiction i.
$SSGCT_i$	=	Seasonal System Generation Combustion Turbine Generation for jurisdiction i.
$SSGCH_i$	=	Seasonal System Generation Cholla for jurisdiction i.
$PPSO$	=	Steam Production Plant less Combustion Turbine and Cholla.
$ADPPSO$	=	Accumulated Depreciation Steam Production Plant less Combustion Turbine and Cholla.
$PPSCT$	=	Steam Production Plant – Combustion Turbine.
$ADPPSCT$	=	Accumulated Depreciation Steam Production Plant – Combustion Turbine.
$PPSCH$	=	Steam Production Plant – Cholla.
$ADPPSCH$	=	Accumulated Depreciation Steam Production Plant – Cholla.
PPS	=	Steam Production Plant .
$ADPPS$	=	Accumulated Depreciation Steam Production Plant.

System Net Plant Production - Hydro Factor (SNPPH)

$$SNPPH_i = \frac{SG_i * (PPHE - ADPPHE) + SG_i * (PPHRP - ADPPHRP)}{(PPH - ADPPH)}$$

where:

$SNPPH_i$	=	**System Net Plant - Hydro Factor** for jurisdiction i.
SG_i	=	System Generation for jurisdiction i.
$PPHE$	=	Hydro Production Plant – East.
$ADPPHE$	=	Accumulated Depreciation & Amortization Hydro Production Plant - East.
$PPHRP$	=	Hydro Production Plant - Pacific.
$ADPPHRP$	=	Accumulated Depreciation & Amortization Hydro Production Plant - Pacific.
PPH	=	Hydro Production Plant.
$ADPPH$	=	Accumulated Depreciation & Amortization Hydro Production Plant.

System Net Plant - Distribution Factor (SNPD)

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$	=	**System Net Plant - Distribution Factor** for jurisdiction i.
PD_i	=	Distribution Plant - for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant - for jurisdiction i.
PD	=	Distribution Plant.
$ADPD$	=	Accumulated Depreciation Distribution Plant.

System Gross Plant - System Factor (GPS)

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i)}$$

$GP\text{-}S_i$ = **Gross Plant - System Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.

System Net Plant Factor (SNP)

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i - ADPPi - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

SNP_i = **System Net Plant Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.
$ADPP_i$ = Accumulated Depreciation Production Plant for jurisdiction i.
$ADPT_i$ = Accumulated Depreciation Transmission Plant for jurisdiction i.
$ADPD_i$ = Accumulated Depreciation Distribution Plant for jurisdiction i.
$ADPG_i$ = Accumulated Depreciation General Plant for jurisdiction i.
$ADPI_i$ = Accumulated Depreciation Intangible Plant for jurisdiction i.

System Overhead - Gross Factor (SO)

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PP_i - PP_oi - PI_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

SOG_i	=	**System Overhead - Gross Factor** for jurisdiction i.
PP_i	=	Gross Production Plant for jurisdiction i.
PT_i	=	Gross Transmission Plant for jurisdiction i.
PD_i	=	Gross Distribution Plant for jurisdiction i.
PG_i	=	Gross General Plant for jurisdiction i.
PI_i	=	Gross Intangible Plant for jurisdiction i.
PP_{oi}	=	Gross Production Plant for jurisdiction i allocated on a SO factor.
PT_{oi}	=	Gross Transmission Plant for jurisdiction i allocated on a SO factor
PD_{oi}	=	Gross Distribution Plant for jurisdiction i allocated on a SO factor
PG_{oi}	=	Gross General Plant for jurisdiction i allocated on a SO factor
PI_{oi}	=	Gross Intangible Plant for jurisdiction i allocated on a SO factor

Income Before Taxes Factor (IBT)

$$IBT_i = \frac{TIBT_i}{\sum_{i=1}^{i=8} TIBT_i}$$

$IBTi$	=	**Income before Taxes Factor** for jurisdiction i.
$TIBTi$	=	Total Income before Taxes for jurisdiction i.

Bad Debt Expense Factor (BADDEBT)

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$ = **Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$ = Balance in Account 904 for jurisdiction i.

Customer Number Factor (CN)

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:

CN_i = **Customer Number Factor** for jurisdiction i.
$CUST_i$ = Total Electric Customers for jurisdiction i.

Contributions in Aid of Construction (CIAC)

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:

$CIAC_i$ = **Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$ = Contributions in Aid of Construction – Net additions for jurisdiction i.

Schedule M - Deductions (SCHMD)

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$SCHMD_i$	=	**Schedule M - Deductions (SCHMD) Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.

Trojan Plant (TROJP)

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$TROJP_i$	=	**Trojan Plant (TROJP) Factor** for jurisdiction i.
$ACCT18222_i$	=	Allocated Adjusted Balance in Account 182.22 for jurisdiction i.

Trojan Decommissioning (TROJD)

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning (TROJD) Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated Adjusted Balance in Account 228.42 for jurisdiction i.

Tax Depreciation (TAXDEPR)

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$TAXDEPR_i$	=	**Tax Depreciation (TAXDEPR) Factor** for jurisdiction i.
$TAXDEPRA_i$	=	Tax Depreciation allocated to jurisdiction i.

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction's total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

Deferred Tax Expense (DITEXP)

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$DITEXP_i$	=	**Deferred Tax Expense (DITEXP) Factor** for jurisdiction i.
$DITEXPA_i$	=	Deferred Tax Expense allocated to jurisdiction i.

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

<u>Deferred Tax Balance (DITBAL)</u>

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_i$	=	**Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

Exhibit
UP&L__(DLT-3S)

PacifiCorp
Exhibit UP&L__(DLT-3S)
Docket No. 02-035-04
Witness: David L. Taylor

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Testimony of David L. Taylor

Appendix D – Special Contracts

May 2004

Protocol Appendix D
Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes Special Contracts without identifiable Ancillary Service Contract attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1

Special Contracts with Ancillary Service Contract Attributes

For allocation purposes Special Contracts with Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Ancillary Service Contract rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2

Buy-through of Economic Curtailment.

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be 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.

Protocol Appendix D - Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Special Contract Customer Revenue		$ 16,000,000		$ 16,000,000	
17	Discount for Ancillary Services				-	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service**					
49						
50	**Cost of Service**					
51	Energy Cost	SE2	$ 498,000,000	$ 166,148,347	$ 248,777,480	$ 83,074,173
52	Demand Related Costs	SG2	$ 998,000,000	$ 334,058,577	$ 496,912,134	$ 167,029,289
53	Sum of Cost		$ 1,496,000,000	$ 500,206,924	$ 745,689,614	$ 250,103,462
54						
55	**Revenues**					
56	Special Contract Revenue	Situs	$ 16,000,000		$ 16,000,000	
57	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,206,924**	**$ 729,689,614**	**$ 250,103,462**

Protocol Appendix D - Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Tariff Equivalent Revenue		$ 20,000,000		$ 20,000,000	
17	Ancillary Service Discount for 75 MW X 500 Hours of Economic Curtailment				$ (4,000,000)	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service & Ancillary Service Contract**					
49						
50	**Cost of Service**					
51	Energy Cost	SE1	$ 498,000,000	$ 166,000,000	$ 249,000,000	$ 83,000,000
52	Demand Related Costs	SG1	$ 998,000,000	$ 332,666,667	$ 499,000,000	$ 166,333,333
53	Ancillary Service Contract - Economic Curtailment (Demand)	SG1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
54	Ancillary Service Contract - Economic Curtailment (Energy)	SE1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
55	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
56						
57	**Revenues**					
58	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
59	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**

Exhibit
UP&L__(DLT-4S)

PacifiCorp
Exhibit UP&L__(DLT-4S)
Docket No. 02-035-04
Witness: David L. Taylor

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Testimony of David L. Taylor

Appendix E – Annual Embedded Costs

May 2004

Protocol Appendix E
Annual Embedded Costs
Example Calculation

Line No	FERC Generation Accounts West Hydro	Description		Mwh	$/Mwh
		Operating Expenses			
1	535 - 545	Hydro Operation & Maintenance Expense	28,742,968		
2	403.330 - 403.336	Hydro Depreciation Expense	9,998,326		
3	404IP	Hydro Relicensing Amortization	-		
4		**Total West Hydro Operating Expense**	38,741,294		
		West Hydro Rate Base			
5	330 - 336	Hydro Electric Plant in Service	374,018,924		
6	302	Hydro Relicensing	60,297,285		
7	108	Hydro Accumulated Depreciation Reserve	(166,680,229)		
8	154	Material & Supplies	33,115		
9		**West Hydro Net Rate Base**	267,669,095		
10		Pre-tax return	12.040%		
11		**Rate Base Revenue Requirement**	32,228,277		
		Annual Embedded Costs			
12		**Hydro-Electric Resources**	70,969,571	4,128,973	17.19
	Mid C Contracts				
13	555	**Annual Mid-C Contracts Costs**	17,395,759	1,942,173	8.96
	Qualified Facilities				
14	555	**Annual Qualified Facilities Costs**	72,455,744	904,760	80.08
	Generation Accounts (Excl. West Hydro, Mid C & QF)	**Description**			
		Operating Expenses			
15	500 - 514	Steam Operation & Maintenance Expense	688,364,976		
16	535 - 545	East Hydro Operation & Maintenance Expense	6,735,263		
17	546 - 554	Other Generation Operation & Maintenance Expense	100,437,128		
18	555	Other Purchased Power Contracts (No Mid-C or QF)	967,640,792		
19	4118	SO2 Emission Allowances	(4,567,668)		
20	403.310 - 403.316	Steam Depreciation Expense	125,299,749		
21	403.330 - 403.336	East Hydro Depreciation Expense	2,682,834		
22	403.340 - 403.346	Other Generation Depreciation Expense	8,246,911		
23	403.399	Mining	-		
24	406	Amortization of Plant Acquisition Costs	5,479,353		
25		**Total Operating Expenses**	1,900,319,339		
		Rate Base			
26	310 - 316	Steam Electric Plant in Service	4,101,422,677		
27	330 - 336	East Hydro EPIS	97,419,645		
28	302	Hydro Relicensing	5,401,310		
29	340 - 346	Other Electric Plant in Service	244,590,200		
30	399	Mining	307,647,355		
31	108	Steam Accumulated Depreciation Reserve	(1,942,212,593)		
32	108	Other Accumulated Depreciation Reserve	(35,481,994)		
33	108	Mining	(163,138,588)		
34	108	East Hydro Accum Depreciation Reserve	(35,722,174)		
35	114	Electric Plant Acquisition Adjustment	157,193,780		
36	115	Accumulated Provision Acquisition Adjustment	(56,601,550)		
37	151	Fuel Stock	63,173,007		
38	253.16 - 253.19	Joint Owner WC Deposit	(4,310,538)		
39	253.99	SO2 Emission Allowances	(45,959,734)		
40	154	Material & Supplies			
41	154	East Hydro Material & Supplies	46,300,904		
42		Total Net Rate Base	2,739,721,705		
43		Pre-tax return	12.04%		
44	(Line 42 x Line 43)	**Rate Base Revenue Requirement**	329,871,889		
45	(Line 25 + Line 44)	**Annual Embedded Costs - All Other \1**	2,230,191,228	69,686,856	32.00
46	(Line 12 + Line 13 + Line 14 + Line 45)	**Total Annual Embedded Costs**	2,391,012,302	76,662,762	31.19

1 . Generation Revenue Requirement less Hydro-Electric Resources, Mid Columbia Contracts and Existing QF Contracts

Exhibit
UP&L__(DLT-5S)

PacifiCorp
Exhibit UP&L__(DLT-5S)
Docket No. 02-035-04
Witness: David L. Taylor

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Supplemental Testimony of David L. Taylor
State by State Revenue Requirement Impact
% Change in Revenue Requirement

May 2004

PacifiCorp
State by State Revenue Requirement Impact
Percent Change in Revenue Requirement

	2005 NPV @ 8.823%	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
California (compared to Modified Accord)															
Modified Accord to Rolled In Adjustment	0.29%	0.91%	0.54%	0.29%	0.30%	0.22%	0.15%	0.12%	0.15%	0.24%	0.23%	0.15%	0.03%	-0.05%	0.37%
Company Owned Hydro	-0.06%	-1.28%	-1.25%	-1.50%	-1.08%	-0.67%	-0.18%	0.47%	0.69%	0.97%	1.26%	1.29%	1.19%	1.17%	1.12%
Total Mid C	0.57%	0.74%	0.72%	0.73%	0.75%	0.73%	0.67%	0.53%	0.46%	0.38%	0.38%	0.37%	0.35%	0.33%	0.34%
QFs	2.21%	2.05%	2.00%	2.00%	2.06%	2.01%	1.98%	2.03%	2.13%	2.44%	2.53%	2.58%	2.59%	2.62%	2.78%
Seasonal	-0.02%	0.00%	-0.01%	0.01%	0.00%	0.01%	-0.01%	-0.01%	-0.03%	-0.06%	-0.04%	-0.05%	-0.04%	-0.05%	-0.05%
TOTAL MSP Solution	2.99%	2.42%	1.99%	1.53%	2.03%	2.30%	2.60%	3.13%	3.41%	3.97%	4.37%	4.34%	4.13%	4.02%	4.56%
Oregon (compared to Modified Accord)															
Modified Accord to Rolled In Adjustment	0.41%	1.28%	0.77%	0.41%	0.43%	0.31%	0.21%	0.17%	0.22%	0.33%	0.32%	0.20%	0.04%	-0.05%	0.49%
Company Owned Hydro	-0.08%	-1.79%	-1.72%	-2.05%	-1.48%	-0.91%	-0.24%	0.65%	0.93%	1.30%	1.70%	1.74%	1.61%	1.57%	1.47%
Total Mid C	-1.71%	-2.08%	-2.06%	-2.15%	-2.22%	-2.21%	-1.92%	-1.64%	-1.47%	-1.22%	-1.23%	-1.21%	-1.15%	-1.10%	-1.12%
QFs	1.19%	2.16%	2.12%	1.92%	1.62%	1.59%	1.57%	1.55%	1.14%	0.09%	0.13%	0.11%	0.12%	0.12%	0.13%
Seasonal	-0.35%	-0.15%	-0.34%	-0.32%	-0.33%	-0.32%	-0.27%	-0.29%	-0.39%	-0.63%	-0.57%	-0.42%	-0.35%	-0.32%	-0.28%
TOTAL MSP Solution	-0.55%	-0.57%	-1.24%	-2.18%	-1.98%	-1.54%	-0.64%	0.44%	0.44%	-0.12%	0.34%	0.42%	0.27%	0.22%	0.68%
Washington (compared to Modified Accord)															
Modified Accord to Rolled In Adjustment	0.39%	1.28%	0.76%	0.40%	0.42%	0.30%	0.20%	0.16%	0.21%	0.32%	0.31%	0.20%	0.03%	-0.07%	0.47%
Company Owned Hydro	-0.06%	-1.81%	-1.74%	-2.08%	-1.49%	-0.91%	-0.24%	0.63%	0.94%	1.31%	1.71%	1.75%	1.62%	1.58%	1.43%
Total Mid C	-0.55%	-0.57%	-0.64%	-0.62%	-0.62%	-0.63%	-1.01%	-0.51%	-0.47%	-0.39%	-0.39%	-0.39%	-0.37%	-0.36%	-0.36%
QFs	-0.67%	-1.07%	-0.91%	-0.93%	-0.77%	-0.72%	-0.70%	-0.70%	-0.50%	-0.17%	-0.50%	-0.49%	-0.49%	-0.48%	-0.48%
Seasonal	0.06%	0.00%	0.00%	0.01%	0.05%	0.05%	0.04%	0.07%	0.10%	0.17%	0.15%	0.09%	0.08%	0.08%	0.06%
TOTAL MSP Solution	-0.82%	-2.16%	-2.52%	-3.21%	-2.40%	-1.92%	-1.71%	-0.36%	0.29%	1.24%	1.28%	1.16%	0.88%	0.76%	1.11%
Utah (compared to Rolled-In)															
Company Owned Hydro	0.04%	1.82%	1.69%	1.97%	1.39%	0.83%	0.22%	-0.57%	-0.81%	-1.12%	-1.45%	-1.47%	-1.36%	-1.31%	-1.17%
Total Mid C	0.78%	1.05%	1.02%	1.04%	1.05%	1.02%	0.93%	0.74%	0.65%	0.53%	0.53%	0.52%	0.49%	0.47%	0.45%
QFs	-0.37%	-0.74%	-0.78%	-0.70%	-0.58%	-0.56%	-0.53%	-0.51%	-0.37%	0.00%	0.02%	0.03%	0.02%	0.02%	0.03%
Seasonal	0.23%	0.10%	0.23%	0.22%	0.24%	0.22%	0.18%	0.19%	0.25%	0.40%	0.36%	0.26%	0.24%	0.21%	0.17%
TOTAL MSP Solution	0.68%	2.23%	2.16%	2.53%	2.10%	1.51%	0.79%	-0.15%	-0.28%	-0.18%	-0.53%	-0.66%	-0.61%	-0.61%	-0.51%
Idaho (compared to Rolled-In)															
Company Owned Hydro	0.19%	1.87%	1.71%	1.97%	1.38%	0.82%	0.21%	-0.55%	-0.79%	-1.09%	-1.40%	-1.43%	-1.31%	-1.25%	-1.12%
Total Mid C	0.79%	1.09%	1.03%	1.03%	1.04%	1.01%	0.92%	0.73%	0.63%	0.51%	0.52%	0.51%	0.47%	0.45%	0.44%
QFs	-0.41%	-0.83%	-0.67%	-0.59%	-0.49%	-0.53%	-0.57%	-0.56%	-0.43%	-0.07%	-0.04%	-0.03%	-0.05%	-0.07%	-0.11%
Seasonal	0.23%	0.21%	0.43%	0.36%	0.31%	0.30%	0.21%	0.18%	0.18%	0.28%	0.27%	0.12%	0.07%	0.04%	0.04%
TOTAL MSP Solution	0.80%	2.33%	2.49%	2.77%	2.24%	1.60%	0.77%	-0.21%	-0.41%	-0.36%	-0.66%	-0.83%	-0.82%	-0.83%	-0.75%
Wyoming (compared to Modified Accord)															
Modified Accord to Rolled In Adjustment	0.40%	1.00%	0.64%	0.39%	0.40%	0.32%	0.26%	0.24%	0.28%	0.36%	0.36%	0.27%	0.15%	0.06%	0.51%
Company Owned Hydro	0.03%	-1.24%	-1.21%	-1.47%	-1.07%	-0.66%	-0.18%	0.49%	0.74%	1.05%	1.37%	1.44%	1.40%	1.36%	1.24%
Total Mid C	0.81%	1.09%	1.05%	1.06%	1.08%	1.05%	0.95%	0.75%	0.65%	0.53%	0.54%	0.53%	0.49%	0.46%	0.45%
QFs	-1.06%	-1.88%	-1.67%	-1.42%	-1.25%	-1.19%	-1.16%	-1.16%	-0.94%	-0.54%	-0.50%	-0.50%	-0.50%	-0.49%	-0.49%
Seasonal	-0.26%	-0.08%	-0.20%	-0.23%	-0.27%	-0.26%	-0.19%	-0.22%	-0.29%	-0.47%	-0.44%	-0.36%	-0.30%	-0.27%	-0.22%
TOTAL MSP Solution	-0.09%	-1.10%	-1.39%	-1.67%	-1.11%	-0.74%	-0.33%	0.10%	0.44%	0.94%	1.32%	1.39%	1.24%	1.12%	1.49%