ENTERED JAN 12 2005

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

In the Matter of	)	
	)	
PACIFICORP	)	ORDER
	)	
Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol.	)	

DISPOSITION: STIPULATION ADOPTED; REVISED PROTOCOL RATIFIED

Summary

In this order, we ratify the *Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol* (Revised Protocol) for use in future rate cases to determine how costs and wholesale revenues associated with PacifiCorp's generation, transmission, and distribution systems will be allocated among its six-state service territory. This new allocation methodology meets the goals we established in March 2002, and is projected to reduce PacifiCorp's Oregon revenue requirement by $45.5 million. Furthermore, to assist our determination of whether the Revised Protocol remains an equitable allocation methodology, we direct PacifiCorp and other parties to more fully develop an alternative allocation methodology, known as the Hybrid Method, for use as a comparator and as a possible means to eliminate cost shifting among PacifiCorp customers in different states.

Background

On March 5, 2002, PacifiCorp filed an application with the Public Utility Commission of Oregon (Commission) pursuant to ORS 756.500(5).[1] PacifiCorp asked the Commission to open an investigation into numerous issues regarding PacifiCorp's multi-jurisdictional status, and to endorse a multi-state process for consideration of these issues.

On March 21, 2002, the Commission considered the matter at its regular public meeting and agreed to open an investigation. The Commission established the following goals and requirements for the multi-state process (MSP):

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[1] This section reads as follows:

Notwithstanding subsection (1) of this section, any public utility or telecommunications utility may make complaint as to any matter affecting its own rates or service with like effect as though made by any other person, by filing an application, petition or complaint with the commission.

1. Determine an allocation methodology that would allow PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation resources;
2. Insure that Oregon's share of PacifiCorp's costs is equitable in relation to other states; and
3. Meet the public interest standard in Oregon.

See, Order No. 02-193.

Over the course of the next two years, various persons representing numerous organizations in the states of Oregon, Utah, Idaho, Washington, and Wyoming met to discuss issues about an allocation methodology for PacifiCorp. A facilitator, Mr. Robert Hanfling, met with the various organizations, and assisted them with information gathering and group discussions. The Commission Staff (Staff), Industrial Customers of Northwest Utilities (ICNU), and Citizens' Utility Board of Oregon (CUB) took the lead in these multi-state work sessions.[2] In addition to the multi-state work sessions, workshops were held with this Commission on June 26, 2002; February 17, 2004; March 31, 2004; and June 16, 2004.

Parties filed at least two rounds of testimony and exhibits. On July 21, 2004, PacifiCorp notified the Commission that Staff, CUB, and PacifiCorp (Joint Parties), but not ICNU, had reached agreement on all issues.[3] On July 23, 2004, PacifiCorp filed a stipulation (Stipulation) signed by the Joint Parties. Attached to the stipulation was a copy of the *Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol* (Revised Protocol) and Appendix A. The other agreed-upon appendices had been attached to PacifiCorp's June 30, 2004 filing in this docket. The Stipulation and Revised Protocol with Appendices A through F are appended as Attachment A and incorporated by reference. On July 26, 2004, the Joint Parties filed testimony in support of the Stipulation.

On August 6, 2004, ICNU filed rebuttal testimony, surrebuttal testimony and testimony in opposition to the Stipulation. Staff and PacifiCorp filed surrebuttal testimony on August 12, 2004. All parties waived their right to cross-examine witnesses. No evidentiary hearing was held. The prefiled testimony was admitted into the record by the parties' affidavit and stipulation. On August 26, 2004, oral argument was held before the three Commissioners and the Administrative Law Judge.

Subsequent to the oral argument, the Commissioners asked the parties to respond to two questions in their post-argument briefs:

> The evidence shows that the Revised Protocol allocation is closer to Rolled In than to Hybrid with respect to the 14-year net present values of Oregon revenue requirements. (See Staff/202,

[2] The other Oregon parties are Portland General Electric Company and Northwest Energy Coalition, neither of which took an active role in the case.
[3] We note that Ronald J. Binz, Public Policy Consulting, also signed the stipulation on behalf of AARP. AARP was not a party in this docket.

> Wordley/31,44.) Assume that the Commission viewed Hybrid as a better approach to cost allocation, but recognized that the public interest is served by obtaining an agreement among (most of) the states.
>
> Based on the above, should the Commission impose conditions on the ratification of the Revised Protocol that: 1) reduce the forecasted deviation from Hybrid with a specified payment to Oregon customers as long as the Commission retains all other provisions of Revised Protocol; and/or 2) limit the allowable percentage increase in Oregon revenue requirement actually caused by the use of Revised Protocol instead of Hybrid (as it is specified by agreement of the parties) in each future rate case?

ICNU and PacifiCorp submitted briefs on September 7, 2004. Staff and CUB filed a joint brief on September 8, 2004.

This Commission, along with the utility regulatory bodies in the States of Washington, Utah, Idaho, and Wyoming, is being asked to ratify the Revised Protocol.

Stipulation and Revised Protocol

The Revised Protocol is a document describing how costs and wholesale revenues associated with PacifiCorp's generation, transmission, and distribution systems will be allocated among the six states.[4] The Revised Protocol does not establish the prudence of any cost related to the allocation of an expense or investment to a particular state. Rather, the prudence of a specific cost is left to each state to determine during future regulatory proceedings.

With adoption of the Revised Protocol, PacifiCorp agrees to continue planning and operating its generation and transmission system on an integrated basis to achieve a least cost/least risk resource portfolio for its customers. Use of the Revised Protocol by all states should provide PacifiCorp a reasonable opportunity to recover its prudently incurred expenses, and should allow PacifiCorp to earn its authorized rate of return. The Joint Parties believe that use of the Revised Protocol achieves a resolution of MSP issues that is in the public interest. Although the Joint Parties intend the terms of the Revised Protocol to be enduring, changed or unforeseen circumstances may occur which require a party to conclude in good faith that the Revised Protocol no longer produces results that are just and reasonable, or in the public interest. In that event, a party will no longer be bound to support the Revised Protocol.

Specific sections of the Revised Protocol describe the four categories of resources (seasonal, regional, state, and system). There are three types of seasonal resources (simple-cycle combustion turbines, seasonal contracts, and Cholla IV/APS), a

[4] PacifiCorp serves a portion of California. Although California did not participate in the MSP, key staff monitored the proceedings.

hydro-endowment regional resource, and three types of state resources (demand-side management programs, portfolio standards, and qualifying facilities contracts). All other resources are system resources, which constitute the vast majority of PacifiCorp resources. Cost shifts related to faster-growing states will be analyzed and quantified by PacifiCorp and the parties. Additionally, a multi-state workgroup will track key factors regarding load growth.

An MSP Standing Committee will be formed, consisting of one member/delegate from each Commission. The MSP Standing Committee will appoint a Standing Neutral to assist the Committee, facilitate discussions among the states, and monitor issues. The Standing Neutral will convene at least one meeting of the MSP Standing Committee each calendar year to discuss inter-jurisdictional issues facing PacifiCorp and its customers. While the MSP Committee may consider possible amendments to the Revised Protocol, any amendments would only go into effect after each Commission that previously ratified the Revised Protocol also ratified the amendments.

The Revised Protocol also contains provisions regarding the treatment of refunctionalized assets; the allocation of administrative and general costs, special contracts, and gain or loss from the sale of resources or transmission assets; and the assignment of distribution costs. Another section discusses the impact of direct access programs for loads lost and sale of freed-up resources.

The Stipulation states that Staff and CUB want to retain PacifiCorp's hydroelectric resources and Mid-Columbia contracts for Northwest citizens. As part of the negotiations, Staff and CUB accepted the Revised Protocol cost allocation for the existing qualifying facilities contracts. Staff and CUB also wanted to make certain that if Oregon customers were responsible for near-term costs and risks of the hydro resources, such as relicensing costs, then Oregon customers should also expect to receive the long-term benefits of these resources. The Joint Parties agreed that if any party proposes a material change to the allocation methods for hydroelectric resources, Mid-Columbia contracts, and existing qualifying facilities contracts, as those terms are defined in the Revised Protocol, the proposed change must be consistent with the trade-off between near-term negative impacts of existing qualifying facilities contracts and long-term positive impact of Mid-Columbia contracts, and the potential near-term costs and long-term benefits of hydroelectric resources.

Also, Staff and CUB did not want faster growing states, such as Utah, to impose unreasonable load growth costs on PacifiCorp customers in slower-growing states, such as Oregon. To address this concern, relatively current Load-Based Dynamic Allocation Factors, as defined by the Revised Protocol, should be used by the slower-growing states. As a basis for comparison, PacifiCorp must provide both the Modified Accord[5] and the Revised Protocol methods as comparators in all of its annual reports and general rate case filings for ten years following Commission ratification of the Revised Protocol.

[5] Modified Accord, with a slight variation adopted in the last stipulated rate case, is the current allocation method used by this Commission.

Finally, the Joint Parties agreed that if: 1) PacifiCorp's annual report of operations shows that its return on equity for Oregon operations, including Type I and Type II adjustments, is 200 basis points or more above the most recently Commission authorized rate of return, and 2) the Oregon Load-Based Dynamic Allocation Factors are forecasted to decline in the fiscal year subsequent to the reporting period, then PacifiCorp will file a tariff rider to establish a credit for Oregon customers.

Hybrid Method

During the course of the proceedings, several alternative allocation methods were discussed. One of these alternative methods, the Hybrid Method, is supported by ICNU.

The Hybrid Method divides the generation system into two regions (East and West) for regulatory accounting purposes. Oregon, Washington and California comprise the West Region, while Utah, Wyoming, and Idaho comprise the East Region. Each state's load, each PacifiCorp-owned resource, and most of the contracts are assigned to a Region. Under this methodology, most of PacifiCorp's existing hydroelectric resources and the majority of long-term power purchases would be assigned to the West Region. The states in each Region would set rates to recover the costs of the generating resources assigned to their Region.

The Hybrid Method includes a process to allocate costs and revenues associated with system balancing purchases/sales and interchanges deemed to be made between the regions. There is also a process for sharing operational reserves between the regions.

The loads in the East Region are forecasted to grow faster than those in the West Region. Utilization of the Hybrid Method would eliminate the concern that West Region customers, such as Oregon, would subsidize the forecasted load growth in the East Region.

The Hybrid Method was developed by a workgroup consisting of representatives from this Commission, the Utah Division of Public Utilities, the Idaho Public Utilities Commission, and PacifiCorp. Because this allocation method was unacceptable to the Utah parties, the assumptions and implementation details were never agreed upon by all states involved in the MSP.

DISCUSSION

Burden of Proof

PacifiCorp must establish, by a preponderance of the evidence, that adoption of the Revised Protocol is in the public interest. In making our determination we will also look to the evidence submitted by Staff and CUB, as they joined PacifiCorp in asking for adoption of the Revised Protocol.

Commission Goals

We established three goals for the MSP in Order No. 02-193. We initially review the Revised Protocol to determine whether it meets those goals.

1. Determine an allocation methodology that would allow PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation resources.

The Joint Parties agree that use of the Revised Protocol by the six states served by PacifiCorp will give PacifiCorp an opportunity to recover its prudently incurred costs. ICNU does not disagree. We find that the Revised Protocol provisions meet this Commission goal.

2. Insure that Oregon's share of PacifiCorp's costs is equitable in relation to other states.

One of the major disagreements between the Joint Parties and ICNU arises from this goal – that Oregon customers would subsidize other states' energy costs, and pay higher rates because of the subsidization under the Revised Protocol. Because subsidization is not eliminated under the Revised Protocol, ICNU urges this Commission to reject it.

Our reading of the equitable sharing goal does not require elimination of subsidization. While we understand that the Oregon coalition had established elimination of subsidization as a principle, our goal was more broadly written. Simply stated, we required that all states concerned be dealt with fairly and equally, which is the definition of "equitable." As long as Oregon, along with the other five states, pay an appropriate share of its costs under the Revised Protocol, then the equitable sharing goal has been met.

ICNU's witness, Mr. Falkenberg, testified, "[I]t is impossible to prove [whether Oregon's share of PacifiCorp's costs is equitable in relation to other states] one way or the other, because to do so would require determination as to what the proper jurisdictional allocation should be in the first place." ICNU/100, Falkenberg/20. This creates a conundrum. To what do we compare to determine if the allocation methodology is equitable? PacifiCorp suggests that we look at how each state's revenue requirement is impacted compared to the current allocation method.

In Oregon, the Revised Protocol, on a net present value basis, is projected to reduce Oregon's revenue requirement by approximately $45.5 million as compared to the Modified Accord method. Utah's revenue requirement increases, due to its relatively higher load growth, reduction of previously allocated hydroelectric resources, and treatment of seasonal resources. The Revised Protocol tries to allocate the benefits of PacifiCorp's system integration with an eye to each state's relative load.

ICNU disagrees with the method used by the Joint Parties in analyzing the benefits of Revised Protocol. ICNU looks at the current average rates of PacifiCorp's service areas, and compares the change in the rates since the merger between Pacific Power and Light and Utah Power and Light. Because Oregon's customer rates have increased while Utah's customer rates have decreased, ICNU argues that the merger was detrimental to Oregon customers. ICNU contends that this Commission has an opportunity to "fix" the effects of the merger in this docket.

The evidence shows that there are other factors besides allocation of generation costs that affect average price per MWh within a state. These factors include the mix of customers, state load factor, and the non-system allocated costs included in revenue requirements. PPL/414, Taylor/4. Further, Staff's analysis describes other factors to explain the difference in Oregon and Utah's average rates, such as distribution plant cost, weatherization loans, supplemental rate schedules, and amortization of demand side management investments. Staff/300, Hellman/2.

Allocation under the Hybrid Method as currently configured would mitigate the subsidization of load growth and would result in lower rates than allocation under the Revised Protocol.[6] However, the use of the Hybrid Method would have a negative effect on other states, particularly Wyoming and Utah. *See,* Staff/100, Hellman/14. We believe that there are benefits to an agreement among all of the states. We also believe there is benefit to further study, which is proposed by the Revised Protocol.

Our review of the testimony and arguments persuades us that the Revised Protocol meets the equitable sharing goal.

3. Meet the public interest standard in Oregon.

ICNU contends the Revised Protocol does not meet the public interest standard because it does not fully protect Oregon customers from the costs of serving load in faster growing states. Because the Revised Protocol does not meet the public interest standard, ICNU urges the Commission to reject it.

The Joint Parties assert that adoption of the Revised Protocol is in the public interest. PacifiCorp established that on a present value basis over the 14-year study period, the Revised Protocol is projected to reduce PacifiCorp's Oregon revenue requirement by approximately $45.5 million (.55 percent) compared to the current Modified Accord method of allocation. Second, Oregon customers retain an entitlement to hydroelectric resources. As for issues of cost shifting among states, further study will occur to identify and implement structural protection mechanisms as needed to guarantee that differential load growth will not result in unwarranted cost shifting.

[6] Using the model runs produced during the MSP, Oregon's allocation of PacifiCorp costs could increase by as much as $62 million because of Utah's higher load growth. Staff/200, Wordley/10.

Staff testified that the Revised Protocol treatment of the hydroelectric resources and the Mid-Columbia contracts; the protection from non-economic decisions of other states; and provisions which enhance Oregon's ability to implement direct access provisions, meet the "public interest" test. Staff also believes that PacifiCorp costs generally will decrease with the resolution of interjurisdictional allocation issues because PacifiCorp will know that it should be able to adequately recover its costs, and not have to make its resource decisions based on the likelihood of cost recovery.

We agree with Staff and hold that ratification of the Revised Protocol is in the public interest. While the Revised Protocol does not eliminate all subsidization, as previously discussed, the Revised Protocol maintains a large majority of the hydroelectric resources and Mid-Columbia contracts for the Northwest. The agreement to accept a larger share of the existing qualifying facilities contract cost, in consideration of revising the treatment of the Mid-Columbia contracts, is appropriate.

The issues of load growth and subsidization need to be addressed in a manner that is equitable to all parties. While we have acknowledged that an acceptable amount of subsidization occurs under the Revised Protocol, we urge the MSP Standing Neutral to make a good faith attempt to further limit cost shifting.

ICNU Conditions

Having found that the Revised Protocol reasonably meets our three goals, we consider whether additional conditions should be imposed. ICNU has proposed five conditions to be added if the Commission chooses to adopt the Revised Protocol:

1. A "most favored nations" clause;
2. Rate mitigation caps;
3. Two specific hydro endowment conditions: one which addresses costs associated with qualifying facilities, and one designed to provide Oregon customers with all of the benefits of the PacifiCorp system;
4. Specific structural safeguards against cost shifting; and
5. Ongoing review of Revised Protocol.

<u>"Most Favored Nations" Clause</u>

Under this condition, ICNU asks that PacifiCorp be required to offer Oregon any condition that PacifiCorp offered to other states. ICNU proposed this condition for two reasons: 1) Because Oregon was intended to be one of the first states to consider ratification, ICNU didn't want Oregon to ratify this version of the Revised Protocol while another state ratified a different version; and 2) if PacifiCorp offered some financial or other inducement for ratification to another state, then the same inducement should also be offered to Oregon.

ICNU's first reason for the condition is essentially moot as Oregon is now one of the last states to ratify the protocol. Further, Section XIII of the Revised Protocol addresses the concern raised by ICNU. This section states that if the Revised Protocol is rejected or materially changed by the Utah, Wyoming or Idaho Commissions following the Oregon Commission's ratification, the material changes must be brought before the Oregon Commission for further review.

As for the second reason, ICNU wants a blanket offer of all conditions to all states, notwithstanding whether there is any rationale for different conditions being offered to different states. ICNU specifically raises this issue due to offers made to the Utah Commission, which are discussed in greater detail below. We are aware of the conditions under which Utah ratified the Revised Protocol, and do not require such conditions to be offered to Oregon prior to our ratification. We do not require this condition to be added.

Rate Mitigation Measures

ICNU asks for rate mitigation caps to limit any increase in PacifiCorp's Oregon revenue requirement and to provide certain specific ratepayer benefits. ICNU argues that subsidization of the Utah system over the past 16 years has caused Oregon's customer classes to pay more while Utah's customer rates have sharply declined. Since the Revised Protocol does not eliminate subsidization, ICNU proposes rate caps, and payment of the $45 million revenue requirement benefit as a rate credit.

ICNU points out that Utah and PacifiCorp entered into a side agreement that established rate caps from 2006 to 2009. These caps limit the amount by which PacifiCorp's Utah revenue requirement can exceed the amount calculated under the existing Rolled-In method.[7] The agreement also granted Rate Mitigation Premiums to PacifiCorp for use from 2010 to 2012. ICNU asserts that these measures will result in harm to Oregon customers. Because of this harm, the Commission should issue rate credits similar to the Utah agreement, comparing the Revised Protocol to the Modified Accord (seasonal) allocation method used in PacifiCorp's last rate case (UE 147).

While we understand the rationale used by Utah and PacifiCorp in establishing such measures due to the customer rate increases in Utah by using the Revised Protocol, we are troubled that some type of rate mitigation was not offered to Oregon customers.[8] However, as there are benefits to Oregon customers under the Revised Protocol, we do not pursue the issue of rate mitigation.

Hydro Endowment

ICNU proposes three conditions regarding the Hydro Endowment:

1. The costs associated with qualifying facilities on a state situs basis should not be included in PacifiCorp's Oregon revenue requirement

[7] This method assumes that all states will pay a portion of PacifiCorp's costs based on the state's share of total system demand, and energy, as well as other factors.
[8] There is some question whether we could legally require rate mitigation caps or credits in this proceeding, as it is not a rate case. Because we declined to require caps or credits, we do not resolve this question.

unless Oregon's portion of the value of the Mid-Columbia contracts exceeds the costs associated with the qualifying facilities on an Oregon situs basis.

2. All benefits of the PacifiCorp hydro system shall be allocated to Oregon customers on the basis of the embedded cost differential method.
3. If, after any point at which the Revised Protocol is adopted by the Oregon Commission, any other state in which PacifiCorp operates decides not to recognize or abide by the Commission-approved Revised Protocol, PacifiCorp will assume the risk of such decisions by those other jurisdictions.

ICNU then set forth specific adjustments to be made to the Revised Protocol language.

ICNU proposes these conditions to ensure the duration and sufficiency of the Hydro Endowment. Specifically, ICNU is concerned that the Hydro Endowment is not permanent, and that Oregon customers do not receive a sufficient amount of the Hydro Endowment.

The Hydro Endowment is clearly viewed as a long term condition of the Revised Protocol and Stipulation. As such, we find it to be sufficiently permanent. We question whether we are even able to make a "permanent" decision such as outlined by ICNU. The Oregon parties' expectations, which are that the Hydro Endowment be long-term, that it be recognized by Utah, and that PacifiCorp not propose treatment of the hydro resources that materially differs from the Revised Protocol, are met. We find that the duration of the Hydro Endowment is sufficient.

As for sufficiency of the benefits, the Revised Protocol establishes a system for allocating cost and resources, not benefits. We agree, as alluded to by PacifiCorp, that trying to allocate benefits would have created more dissension for the involved states than allocating costs and resources. The discussion of the Hydro Endowment in the Stipulation and Revised Protocol provides the assurances needed by the Commission.

Finally, we do not adopt the clause stating that PacifiCorp assumes the risk of other jurisdictions "backing out" of the Revised Protocol. We expect that if any state has issues about the Revised Protocol, these issues will be discussed by the Standing Committee. Further, even if another state "backs out," we still maintain our ability to determine whether the Revised Protocol is the appropriate allocation method.

<u>Cost Shifting Safeguards</u>

ICNU asks that the Commission adopt, or in the alternative, the parties develop, cost shifting safeguards. ICNU also suggests that the Oregon revenue requirement be adjusted by imputing market revenues to new plants to address costs shifted from faster growing states to slower growing states until the safeguards are put in place.

This condition is in conflict with the Revised Protocol, which we are ratifying by this order. The multi-state parties are committed to working on the cost shifting issue. We will allow that process to be used to resolve any ongoing cost shifting.

Ongoing Review

ICNU's final condition is:

> In the event that ScottishPower seeks, or is required, to obtain Commission approval to sell, merge, or transfer ownership of PacifiCorp pursuant to Oregon law, then all aspects of the Revised Protocol shall be subject to review.

This provision is not necessary, as this Commission *always* has, and retains, the authority to review the Revised Protocol. The question is under what circumstances will we exercise that authority. Clearly, the Revised Protocol provides a process for revision. There may be other circumstances that would require a review of the Revised Protocol. However, we will wait until the need arises to review the Revised Protocol, rather than speculate on what circumstances would trigger our review. This condition is not adopted.

In sum, we will not add any of the conditions proposed by ICNU. As previously stated, the Revised Protocol meets our established goals. Therefore, additional conditions are not needed to satisfy the public interest standard. We are also concerned that these proposed conditions would undermine the consensus reached among the states. To possibly jeopardize the overall agreement by adding unacceptable conditions to the Revised Protocol is not in the public interest. We do not adopt INCU's proposed conditions.

Commission Conditions

Our bench request asked the parties whether we should impose two conditions on the ratification of the Revised Protocol:

1. Reduce the forecasted deviation from Hybird with a specified payment to Oregon customers; and
2. Limit the allowable percentage increase in Oregon revenue requirement actually caused by the use of the Revised Protocol instead of the Hybrid Method.

The Joint Parties opposed the suggested conditions. ICNU supported both conditions.

There has been a great deal of discussion about the benefits of the Hybrid Method. While we conclude that the two conditions set forth in our bench request should not be adopted, we agree with ICNU that the Hybrid Method should not be abandoned.

Section IV.E. of the Revised Protocol requires PacifiCorp, in consultation with the MSP Standing Committee and other parties, to file a report regarding load growth issues no later than nine months following the filing of PacifiCorp's 2004 Integrated Resource Plan (IRP). According to the Revised Protocol, this report will include a description of one or more options for structural protection against cost shifting. We direct PacifiCorp to include a fully developed Hybrid Method as one of options for structural protection in this report. To accomplish this, PacifiCorp should work with parties from Oregon and those interested from other states. This Hybrid Method should be designed to meet the three original Commission goals in Order No. 02-193. Once completed, the participating Oregon parties are to present the Hybrid Method to the Commission no later than December 1, 2005.

Furthermore, while the Revised Protocol uses the Modified Accord as a comparator for the Revised Protocol, we want to also use the Hybrid Method as a comparator. Therefore, upon approval of the agreed-upon Hybrid Method, or January 1, 2006, whichever comes first, PacifiCorp must file its annual reports and general rate case filings comparing results under the Revised Protocol with both Modified Accord and Hybrid Method results.

Finally, we would also like the Standing Committee to study variations of the Hybrid Method as a means to eliminate any cost shifting. Of course, we are open to looking at any resolution of this issue.

Conclusion

This has been a long process, with a great deal accomplished over the almost three years since this docket was opened. The goals established by the Commission have been met, although there is still work to be done. We hope that the Revised Protocol works for all of the states by providing certainty along with improved methods for allocating PacifiCorp's resources.

After reviewing the Stipulation and supporting testimony, the Commission concludes that the Stipulation and Revised Protocol are an appropriate resolution of all the issues. We adopt the Stipulation in its entirety and ratify the Revised Protocol.

ORDER

IT IS ORDERED that:

1. The Stipulation is adopted and the Revised Protocol is ratified. Both documents are appended as Attachment A.

2. The Oregon parties are to devise a fully functional Hybrid Method no later than December 1, 2005.

3. PacifiCorp must file its annual reports and general rate case filings using both Modified Accord and the revised Hybrid Method as comparators beginning January 1, 2006, or once the Hybrid Method is completed, whichever occurs first.

Made, entered, and effective ____________________________.

Lee Beyer Chairman	**Ray Baum** Commissioner

Concurring Opinion of Commissioner John Savage

I concur with the finding that ratification of the Revised Protocol is in the public interest.

I believe, however, that the Hybrid Method of cost allocation (Staff/102, Hellman/62-66) is superior to the Revised Protocol in some ways. The Hybrid Method retains the Hydro Endowment without the need for offsetting adjustments through the state-situs allocation of Qualifying Facility costs. The Hybrid Method assigns costs that are more closely aligned with the principle of cost-causation than does the Revised Protocol (for example, Oregon is not as exposed to the costs of meeting load growth in other states under the Hybrid Method). And it would result in lower costs to Oregon ratepayers (Staff/202, Wordley/31 and 44). Its failing is that it is not acceptable to the other states, just as Utah's preferred approach – the Rolled-In Method – is not acceptable to Oregon.

As the record shows, there would be a cost to Oregon ratepayers if the states fail to adopt a common cost-allocation method that would allow Pacific the opportunity to recover reasonable and prudently incurred costs. The Revised Protocol is acceptable to the other states, and on balance, adopting it is in the public interest.

This order requires PacifiCorp to work with other parties to refine the Hybrid Method and to show the results of both the Hybrid Method and the Revised Protocol in future rate cases. I will look to those comparative results to gauge whether just and reasonable rates for PacifiCorp's customers should be based on the consensus Revised Protocol or on a cost-allocation closer to the results of the Hybrid Method.

____

John Savage
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

In the Matter of PACIFICORP Requesting to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol.	STIPULATION

PARTIES

1. The parties to this Stipulation are: a) PacifiCorp (or "the Company"), b) the Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB") or collectively, the "Oregon Parties" and c) AARP.

BACKGROUND

2. As a result of discussions among representatives of PacifiCorp, Oregon, Utah, Washington, Idaho and Wyoming regarding issues arising from PacifiCorp's status as a multi-jurisdictional utility, the Company has proposed interjurisdictional cost allocation methods that are embodied in a document titled the "Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol" ("Revised Protocol"). PacifiCorp has asked that the Public Utility Commission of Oregon ("OPUC") and the utility commissions of the other jurisdictions in which it operates, ratify the Revised Protocol and use its allocation methodology in future regulatory proceedings. A copy of the Revised Protocol is attached as Exhibit A to this Stipulation. Capitalized terms used in this Stipulation are to have the same meaning as those used in the Revised Protocol and as set forth in its Appendix A.

3. Included in the provisions of the Revised Protocol are those specifying how PacifiCorp's Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts will be allocated among the States.

4. Throughout this proceeding, Oregon Parties have made clear the importance of maintaining the Hydro-Electric Resources and Mid-Columbia Contracts for Northwest citizens. An allocation of these Resources to Oregon that is less than that contemplated by the Revised Protocol is not acceptable to Oregon Parties. In order to secure the allocation of the Mid-Columbia Contracts that is contemplated in the Revised Protocol, Oregon Parties have accepted the allocation of the costs of Existing QF Contracts that is contemplated in the Revised Protocol.

5. The parties to this Stipulation recognize that there is uncertainty regarding the future value of the Mid-Columbia Contracts and that it is possible that, during the remaining term of the Existing QF Contracts, the costs to Oregon customers associated with the contemplated allocation of Existing QF Contracts will exceed the benefits of the contemplated allocation of Mid-Columbia Contracts. However, the Oregon Parties are prepared to assume this risk because they expect that the contemplated allocation of Mid-Columbia Contracts will continue to provide long-term benefits to Oregon customers after the expiration of the Existing QF Contracts. Similarly, the parties to this Stipulation recognize that the addition of relicensing costs to the Company's ratebase may cause the Hydro-Electric Resources to be more costly than other market opportunities in the near term, but Oregon Parties are willing to accept responsibility for these higher near-term costs in the expectation that, as the relicensing costs are depreciated, Hydro-Electric Resources will yield long-term benefits to Oregon customers. For the foregoing reasons, it is critical to Oregon Parties that their entitlement to Hydro-Electric Resources and Mid-Columbia Contracts not be abridged at any time in the future.

6. Oregon Parties have been concerned that relatively faster-growing States cause other States to unreasonably support the costs associated with that faster load growth. Load-Based Dynamic Allocation Factors cause costs to be shifted to relatively faster-growing States. However, in order to insulate slower-growing States from the consequences of faster load growth in other States, rates in relatively slower-growing States should incorporate relatively current

Load-Based Dynamic Allocation Factors, which reflect an appropriate level of relative cost responsibility.

AGREEMENT

7. The undersigned parties hereby stipulate and agree that they will support the ratification of the Revised Protocol by the OPUC and that they will file and defend testimony supporting the use of the Revised Protocol as appropriate. Except as otherwise provided below, PacifiCorp agrees that, as long as the Revised Protocol, or any amended version of the Revised Protocol recommended by the MSP Standing Committee, is relied upon by the OPUC for purposes of inter-jurisdictional allocation of the Company's costs, all PacifiCorp's general rate case filings in Oregon will be based upon same. Except as otherwise provided below, the Oregon Parties agree that, until such time as the Revised Protocol is amended in accordance with its terms, they will support the use of the Revised Protocol for allocating costs among PacifiCorp's jurisdictions.

8. Should the benefits or detriments to Oregon customers of the contemplated allocations as specified in the Revised Protocol, or any amended version of the Revised Protocol recommended by the MSP Standing Committee, no longer produce results that are just, reasonable and in the public interest, any party to this Stipulation may propose amendments to the Revised Protocol or propose to the OPUC that the OPUC depart from its terms, so as to produce results that are just, reasonable and in the public interest.

9. Notwithstanding the status of the Revised Protocol as an inter-jurisdictional cost allocation method, if any party to this Stipulation proposes a material change to the allocation methodology for Hydro-Electric Resources, Mid-Columbia Contracts or Existing QF Contracts as specified in the Revised Protocol, the proposed change should be consistent with the trade-off between near-term negative impacts of Existing QF Contracts and long-term positive impacts of

Mid-Columbia Contracts and the potential near-term costs and long-term benefits of Hydro-Electric Resources as described in Sections 4 and 5 of this Stipulation.

10. As provided for in Section XIII C of the Revised Protocol, a party's initial support of the Revised Protocol will not bind that party in the event that unforeseen circumstances cause that party to conclude that the Revised Protocol no longer produces just and reasonable results. To allow Oregon Parties to monitor the impacts of the Revised Protocol, the Company's annual reports of operation, and general rate case filings filed with the OPUC for the ten years following the OPUC's ratification of the Revised Protocol shall include calculations of the Company's Oregon revenue requirement under both the Revised Protocol and the Modified Accord methods, and shall include and adequately explain all adjustments, assumptions, work papers and spreadsheet models used by the Company in making such calculations. Such annual reports shall also include forecasts of Load-Based Dynamic Allocation Factors for the Company fiscal year subsequent to the reporting period.

11. In consideration of the concerns set forth in Section 6, the parties to this Stipulation agree that following Commission ratification of the Revised Protocol, and as long as Load Based Dynamic Allocation Factors are relied upon by the OPUC for allocating costs of New Resources:

(a) If the Company's annual report of operations demonstrates that the Company's return on equity for its Oregon operations, including Type I and Type II adjustments, is 200 basis points or more above the most recently authorized rate of return in Oregon, and

(b) Oregon's Load-Based Dynamic Allocation Factors are forecasted to decline in the fiscal year subsequent to the reporting period, then:

(c) The Company will file within 90 days to establish a tariff rider that credits to Oregon customers the difference between the results of operations as filed and the results of operations restated using the forecasted Load-Based Dynamic Allocation Factors for the fiscal year subsequent to the reporting period.

(d) The tariff rider will remain in effect until the earlier of:

(i) the effective date of a rate change from a general rate proceeding, or

(ii) one year from the effective date of the tariff rider.

(e) The Company's annual report of operations as provided for in subsection (a) shall not include the effects of any tariff rider pursuant to this section.

12. Within 30 days following the date that the Revised Protocol is finally ratified, as contemplated in Section XIII D of the Revised Protocol, the Company shall initiate efforts with each Commission that has finally ratified the Revised Protocol to organize the MSP Standing Committee. Within 90 days of such final ratification of the Revised Protocol, the Company shall file with each Commission that has finally ratified the Revised Protocol a proposed budget sufficient to reasonably fund the appointment of the Standing Neutral and the activities described in Section XIII B of the Revised Protocol for a 12-month period.

13. If the Revised Protocol is ratified by the Commission, if so requested by the Commission within 90 days of such ratification, PacifiCorp will make a filing in Oregon for the purpose of changing rates so as to implement the Revised Protocol. Nothing in this Stipulation shall otherwise alter or abridge PacifiCorp's right to initiate Oregon rate proceedings when it deems appropriate to do so.

Signatures

This stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

Dated this 21st day of July, 2004.

PACIFICORP

____
Andrea L. Kelly
Managing Director

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

____
Stephanie S. Andrus
Oregon Department of Justice

CITIZENS' UTILITY BOARD OF OREGON

____
Robert Jenks
Executive Director

AARP

____
Ronald J. Binz
Public Policy Consulting

Table of Contents

The Revised Protocol

I. Introduction

This PacifiCorp Inter-Jurisdictional Cost Allocation Protocol is the result of extensive 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 commits that it will continue to plan and operate its generation and transmission system on a six-State integrated basis in a manner that achieves a least cost/least risk Resource portfolio for its customers.

The 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 expenses and investments and earn its authorized rate of return. The assignment of a particular expense or investment, or allocation of a share of an expense or investment, to a State pursuant to the Protocol is not intended to, and should not, prejudge the prudence of those costs. Nothing in the Protocol shall abridge any State's right and/or 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. Parties who have supported the ratification of the Protocol do so in the belief that it will achieve a solution to MSP issues that is in the public interest. However, a party's support of the Protocol is not intended in any manner to negate the necessary

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

flexibility of the regulatory process to deal with changed or unforeseen circumstances, and a party's support 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, in good faith, that the Protocol no longer produces results that are just, reasonable and in the public interest. Support of the Protocol shall not be deemed to constitute an acknowledgement by any party of the validity or invalidity of any particular method, theory or principle of regulation, cost recovery, cost of service or rate design and no party shall be deemed to have agreed that any particular method, theory or principle of regulation, cost recovery, cost of service or rate design employed in the Protocol is appropriate for resolving any other issues.

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 Contracts and related 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 be effective and apply to all PacifiCorp retail general 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 Resource 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 following three types of Seasonal Resources will be 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.

The MSP Standing Committee will review Seasonal Resources criteria and allocation. Items to be considered include the seasonal patterns of Resource operation to determine seasonality, the treatment of associated off-system sales, the value of operating reserves provided from Seasonal Resources, criteria to define seasonal Exchange Contracts and methods for allocating the costs of seasonal exchange returns.

B. Regional Resources

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

1. Hydro-Endowment:

a. <u>Owned Hydro Embedded Cost Differential Adjustment.</u> 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. <u>Mid-Columbia Contract Embedded Cost Differential Adjustment:</u> 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. Unless otherwise recommended by the MSP Standing Committee, as long as the Oregon parties that originally supported ratification of the Protocol continue to support the use of the Protocol for purposes of establishing the Company's Oregon revenue requirement, PacifiCorp will not propose or advocate any material change in the Protocol provisions related to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts. Provided, however, the foregoing provision shall not prevent the Company from complying with any Commission order.

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 State 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, Regional Resources or State Resources are System Resources. Generally, all Fixed Costs associated with System Resources and all costs 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 2004 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 other factors deemed relevant to this issue. No later than nine months after filing the 2004 IRP, the Company, in consultation with the MSP Standing Committee and other parties, will file a report with the Commissions regarding this issue. Included in this report will be a description of one or more options for a structural protection

[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.

mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction.

The MSP Standing Committee is charged with developing one or more ameliorative mechanisms that could be implemented in a timely manner in the event that the studies show a material and sustained net harm to particular States from the implementation of the IRP. The MSP Standing Committee should consider the impact of load growth in light of all other relevant factors. Potential mechanisms to be studied include tiered allocations, treatment of 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.

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. Any refunctionalization will be implemented under the guidance of the MSP Standing Committee.

Costs associated with transmission assets, and firm wheeling expenses 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 expenses and revenues will be allocated among the States based upon the SE Factor.

VI. Assignment of Distribution Costs

All distribution-related expenses and investment that can be directly assigned will be directly assigned to the state where they are located. Those 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 Contracts

Revenues associated with Special Contracts will be included in State revenues and loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. Special Contracts may or may not include Customer Ancillary Service Contract attributes. In recognition that Special Contracts may take different forms, Appendix D provides a written description and numeric example of the regulatory treatment of Special Contracts and associated discounts.

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.

<u>X. Implementation of Direct Access Programs</u>

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.
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 but will not be included in Load-Based Dynamic Allocation Factors for New Resources acquired after the election to permanently choose Direct Access or opt out of New Resources. An effective date for this process will be established at such time as customers permanently choose Direct Access or opt out, and this process will be implemented under the guidance of the MSP Standing Committee.
3. In each State with Direct Access Customers, an additional step will take place for ratemaking purposes to establish a value or cost (which could include a transfer of Freed-Up Resources between customer classes within a State) resulting from the departure of the departing load; other States do not implement the second step.

B. Freed-Up 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 to Direct Access Customers in a manner that satisfies the "no-harm" standard in respect to customers in the other States. The parties agree that they will not advocate a sale of Freed-Up Resources to be consummated if the proposed allocation of the gain or loss from the sale 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 intent of the parties who have supported the ratification of the Protocol.

B. MSP Standing Committee

1. An MSP Standing Committee will be organized consisting of one member or delegate 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.

5. The MSP Standing Committee has the immediate assignments of: (a) developing one or more mechanisms that could be implemented in a timely manner in the event that load growth studies show a material and sustained net harm to particular States from the implementation of the IRP; and (b) reviewing Seasonal Resources criteria and allocation, including seasonal patterns of Resource operation to determine seasonality, treatment of associated off-system sales, the value of operating reserves provided from Seasonal Resources, criteria to define seasonal Exchange Contracts and methods for allocating the costs of seasonal exchange returns.

6. The work of the MSP Standing Committee will be supported by sound technical analysis. A party supporting ratification of the Protocol will work in good faith to address issues being considered by the MSP Standing Committee.

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.

D. Interdependency among Commission Approvals

The Protocol has been developed by the parties as an integrated, inter-dependent, organic whole. Therefore, final ratification of the Protocol by any of the Commissions of Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon similar ratification of the Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions. Upon any rejection of the Protocol, or any material deletion, alteration, or addition to its terms, by any one or more of the four Commissions, the Commissions who have previously conditionally adopted the Protocol shall initiate proceedings to determine whether they should reaffirm their prior ratification of the Protocol, notwithstanding the action of the other Commission or Commissions.

The Protocol shall only be in effect for a State upon final ratification by its Commission. The Company will continue to bear the risk of inconsistent allocation methods among the State

Appendix A

Revised Protocol Definition of Terms

Revised 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. If a State implements a Direct Access Program pursuant to which Freed-Up Resources are transferred between customer classes, such transfers shall be considered Direct Access Purchases and Sales.

“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 its energy requirements.

“Existing QF Contracts” means Qualifying Facility Contracts entered into prior to the effective date of this Protocol, but not such contracts renewed or extended subsequent to the effective date of this Protocol.

“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.

"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 as established pursuant to Paragraph XA2 of the Protocol.

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

"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.

"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.

"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.

Appendix B

Allocation Factor Applied to Each Component for Revenue Requirement

Revised 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

Appendix C

Allocation Factor Algebraic Definitions

Revised Protocol Appendix C
Allocation Factors
Algebraic Definitions
November 29, 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.

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.

$WMO_{jCT} = \dfrac{\sum_{ct=1}^{n} E_{jct}}{\sum_{j=1}^{12}\sum_{ct=1}^{n} E_{jct}}$ 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

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.

$WMO_{jCT} = \frac{\sum_{ct=1}^{n} E_{jct}}{\sum_{j=1}^{12} \sum_{ct=1}^{n} E_{jct}}$ 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

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.

Seasonal System Generation Cholla (SSGCH)

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

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.

Mid-C (MC)

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

where:

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

$$WMCE_i = E^*_{ipr} + (E_{rr} * \text{SGi}) + (E_{wa} * WWA_i) + (E_w * \text{SGi})$$ 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.

<u>System Net Plant Production - Hydro Factor (SNPPH)</u>

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

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.

<u>System Net Plant - Distribution Factor (SNPD)</u>

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

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.

<u>System Gross Plant - System Factor (GPS)</u>

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

$GP\text{-}S_i$ = **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.

<u>System Net Plant Factor (SNP)</u>

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

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:

$TAXDEPR_{\boldsymbol{i}}$	=	**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:

$DITEXP_{\boldsymbol{i}}$	=	**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.)

Deferred Tax Balance (DITBAL)

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

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.)

Appendix D

Special Contracts

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**

Appendix E

Annual Embedded Costs

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		
12		**Annual Embedded Costs 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

Appendix F

Methodology for Determining Mid-C (MC) Factor

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 / Calculation of Mid C Factor

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%

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

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%

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

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%

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