Exhibit ___T (APB-1T)
Docket UE-061546
Witness: Alan P. Buckley

BEFORE THE WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, vs. PACIFICORP dba Pacific Power & Light Company, Respondent.	DOCKET UE-061546
In the Matter of the Petition of PACIFIC POWER & LIGHT COMPANY For an Accounting Order Approving Deferral of Certain Costs Related to the MidAmerican Energy Holdings Company Transition.	DOCKET UE-060817

TESTIMONY OF

Alan P. Buckley

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

February 16, 2007

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan P. Buckley. My office address is 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504, and my e-email address is abuckley@wutc.wa.gov.

Q. What are your professional qualifications?

A. I am employed by the Commission as a Senior Policy Strategist. Among other duties, I am responsible for analyzing rate and power supply issues as they pertain to the investor-owned utilities under the jurisdiction of the Commission. I received a B.S. degree in Petroleum Engineering with Honors from the University of Texas at Austin in 1981. In 1987, I received a Masters of Business Administration degree in Finance from the University of California at Berkeley.

From 1981 through 1986, I was employed by Standard Oil of Ohio (now British Petroleum-America) in San Francisco as a Petroleum Engineer working on Alaskan North Slope exploration drilling and development projects. From 1987 to 1988, I was employed as a Rates Analyst at Pacific Gas and Electric Company in San Francisco. Beginning in late 1988 until late 1992, I was employed by R.W. Beck and Associates, an engineering and consulting firm in Seattle, Washington, conducting cost-of-service and other rate studies, carrying out power supply studies, analyzing mergers, and analyzing the rates of Bonneville Power Administration and the Western Area Power Administration.

I came to the Commission in December 1993, where I have held a number of positions including Utility Analyst, Electric Program Manager, and the position that I presently hold. I have been a witness in numerous proceedings before the Commission. I also have been a witness in proceedings at the Bonneville Power Administration and at the Federal Energy Regulatory Commission.

Q. Have you filed testimony on issues of inter-jurisdictional allocation, power supply, and power cost adjustment mechanisms in previous PacifiCorp proceedings before this Commission?

A. Yes. I have filed extensive testimony on inter-jurisdictional cost allocation, power supply costs, and power cost adjustment issues in the last two general rate cases filed by PacifiCorp before this Commission. This includes consolidated Dockets UE-050684, UE-005412 and UE-060669, in which the Commission stated the requirements for an acceptable cost allocation methodology for PacifiCorp. I will refer to that case as the "2005 Rate Case" in my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's recommendations in regards to: 1) the proposed Western Control Area (WCA) allocation methodology; 2) the base level of Washington net power supply expense; 3) the proposed Power Cost Adjustment Mechanism ("PCAM"); and 4) the prudence of certain resources the Company has acquired.

II. Summary

Q. Please summarize Staff's recommendations related to the items you have identified.

A. Staff recommends the Commission:

a. Approve the use of the Western Control Area allocation methodology, with certain modifications, for purposes of determining rates in Washington.

b. Approve a Washington base net power supply expense level of $92,385,102, which represents a $3,067,859 reduction in Washington net power supply expense, as compared to the level PacifiCorp filed in its direct case. This also represents the base level of net power supply expense that will be used in the Staff's proposed PCAM.

c. Approve a Power Cost Adjustment Mechanism (PCAM) with certain modifications from the PCAM the Company proposes, as well as certain reporting requirements.

d. Find that certain resources recently acquire by the Company were prudently acquired.

I discuss each of these recommendations in more detail below.

Q. Between the 2005 Rate Case and prior to the Company's filing of its evidence in this docket, did you discuss cost allocations and relates issues with the Company?

A. Yes. In Paragraph 100 of its Order 04 in the 2005 Rate Case, the Commission requested PacifiCorp to work with the parties on the issue of an acceptable power cost adjustment mechanism, or "PCAM." Staff met with the Company on an informal basis on a number of occasions to discuss the PCAM and related issues, including allocations. The discussions focused on methodologies that would meet the Commission's requirements set forth in its Order in the 2005 Rate Case, and address other concerns expressed by Staff. In addition, I discussed these issues with the Company in the technical workshops scheduled by the Commission in this docket.

Q. Does the Company's filing in this docket address the Commission's and Staff's concerns relating to the issues of inter-jurisdictional cost allocations, power supply expense, and a power cost adjustment mechanism?

A. Yes. First, in this docket, the Company has decided to abandon the Revised Protocol methodology for use in Washington. This is a major shift in the Company's approach. Second, the Company has agreed to adopt a Western control area-based method for cost allocations and for determining power supply costs, including the implementation of a PCAM. Finally, the PCAM the Company filed is responsive to the concerns expressed by the Commission in its Order 04, although Staff recommends some changes to the PCAM the Company filed.

III. Discussion

A. Western Control Area Allocation Methodology

Q. Please summarize Staff's recommendations regarding the Western Control Area (WCA) methodology.

A. Staff recommends that the Commission approve the use of the WCA methodology, with modifications, for use in determining the Company's rates for electric service in Washington. In addition, Staff recommends that the Commission order a formal five-year review period for purposes of evaluating the effectiveness of that methodology. All other aspects of the WCA methodology would remain as filed, including the resources assigned to the Western control area.

1. Staff's modifications to the WCA methodology filed by PacifiCorp

Q. What modifications to the WCA methodology does Staff propose?

A. Staff proposes two modifications to the WCA methodology filed by the Company. First, Staff proposes a 75 percent demand/25 percent energy allocation factor for fixed production costs, instead of the 100 percent energy allocation proposed by PacifiCorp.

The second modification relates to the way the Company's WCA GRID model carries out system balancing transactions. Staff proposes that a third market "bubble" be established that provides for sales to the Eastern control area, when and if those sales are determined to be economic.

These are the only two WCA methodology-related adjustments Staff is proposing at this time. However, as discussed below, the WCA methodology allows for further modifications in order to meet both Company and Commission requirements.

a. Adjustment 5.5, Revised CAGW & SO Allocators

Q. What is the basis for Staff's first modification, to change the allocation of fixed production costs to 75 percent demand and 25 percent energy?

A. This modification better aligns the allocation of WCA methodology fixed production costs with the more traditional use of a demand-weighted allocation for fixed cost components in a cost-of-service study. In addition, the demand/energy-based allocation is more in line with how the Company historically allocated fixed production costs and now utilizing in other inter-jurisdictional allocation methodologies.

Q. How does this first modification affect Washington revenue requirements?

A. It mainly affects the production rate base component of the Company's revenue requirement. However, there are additional revenue requirement effects because other allocators are adjusted in response to the changes in rate base. The overall effect of this modification is identified in Mr. Schooley's Exhibit ___ (TES-2), Adjustment 5.5. There is no change to Washington net power supply expense as a result of this modification.

b. Adjustment 5.4, Miscellaneous Power Supply, Eastern Market Modification

Q. What is the basis for Staff's second modification, to add a third market "bubble"?

A. This modification creates an opportunity for sales from the Western control area along the Bridger path into the Eastern control area, utilizing assumed available transmission capacity during high load hours. Potential sales volume is further limited due to competition from other generators available to the Company's Eastern control area.

The model credits the Western control area for economic sales using a "share the margin" approach. This allows the Western control area to benefit from economic sales to the Eastern control area on an "as available" basis, without receiving an allocation of any additional costs, such as Eastern control area transmission expenses.

This methodology replaces the use of only the Mid-Columbia and COB markets for system balancing transactions, and provides additional benefits to the West (and Washington) through sales to the Eastern control area.

Q. How is this second modification implemented?

A. The method for implementing this second modification is identified in the Company's response to Staff Data Request 88, which is attached as my Exhibit ___ (APB-2). For purposes of this proceeding, I am recommending that the Commission accept this modification to the WCA methodology based on this data request response, recognizing that a number of alternative methodologies could be developed.

Q. What is the effect of the proposed Eastern market "bubble" modification on Washington revenue requirements?

A. This modification affects the calculation of net power costs because it adds an additional market for sales. The effect on the base level of net power supply expense is included as an integral part of the other adjustments to net power supply expense that will be identified later in my testimony.

Q. Are there other potential modifications to the WCA methodology that you investigated?

A. Yes. The proposed WCA methodology includes the costs and benefits associated with the Company's Klamath Hydroelectric Project in Southern Oregon. It is fair to say that there has been some controversy at the local, state, and federal level regarding these projects, including potential requirements as part of any new FERC license. These requirements may affect the economic viability of the project going into the future. Although Staff includes the project's present costs and benefits in the determination of net power supply expense for this proceeding, Staff reserves the right in subsequent proceedings to further address the prudence of the project, if any additional requirements are imposed on the Company as a result of the continuing re-licensing process.

2. *Staff's review of the WCA methodology*

Q. In its orders in the 2005 Rate Case, did the Commission state the requirements for an acceptable inter-jurisdictional cost allocation methodology?

A. Yes. In Order 04 in the 2005 Rate Case, the Commission set clear standards on how it would evaluate an allocation methodology for use in Washington. The Commission reiterated these requirements in Order 06 in that docket.

Q. Based on your review of those Orders, what are the key requirements stated by the Commission?

A. In paragraph 48 of Order 04, the Commission states:

> In setting rates, we must follow certain statutory standards. In particular, we must regulate in the public interest, ensuring that in determining the fair value of company property for rate making purposes, i.e., establishing the appropriate rate base, we must determine whether the property is "used and useful for service in this state."

In paragraph 50, the Commission expands on the "used and useful for service in this state" requirement:

> Under our governing statutes, we must find a resource to be used and useful in this state before its costs may be recovered in rates. We interpret the phrase "used and useful for service in this state" to mean benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource

to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits).

Q. Does the WCA methodology meet these Commission requirements for an acceptable allocation methodology?

A. Yes. The WCA methodology is a control area-based method. The use of a control area based methodology addresses the identification of costs and benefits associated with direct service to Washington customers.

Q. What is a control area?

A. A control area can be defined in several ways. For example, a control area is defined as:

- An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection. (Western Area Power Administration)

or

- A part of a power system or a combination of systems to which a common generation control scheme is applied to match generation and load. (Bonneville Power Administration)

or

- An electric system, consisting of one or more electric utilities, capable of regulating its generation to maintain an interchange schedule with other systems and capable of contributing to the frequency regulation of the regional interconnected grid. (Federal Energy Regulatory Commission)

Q. What is significant about the concept of a control area for purposes of an inter-jurisdictional cost allocation method?

A. The resources within a control area are used to provide benefits to the system within that control area.

Q. How many control areas does PacifiCorp have?

A. PacifiCorp has two control areas: the Eastern control area and the Western control area. Washington is located in the Western control area.

Q. How does the WCA methodology address the requirement that allocated resources be "use and useful for service in this state?"

A. The WCA methodology is a control area based model. It is based on the Company's Western control area, which includes Washington. The WCA method starts with only loads and resources contained within PacifiCorp's Western control area for operational purposes.

Q. How does the WCA methodology address facilities that span both control areas?

A. The WCA allocates to each control area a portion of the costs and benefits associated with certain facilities that span both control areas. For example, the Company's Jim Bridger facility is electrically connected to both the Company's Eastern and Western control areas. The WCA allocates a portion of Jim Bridger to Washington.

Q. In sum, how does the WCA methodology satisfy the "used and useful" requirement?

A. The WCA methodology satisfies the "used and useful" requirement because it isolates the costs and benefits associated with Western control area loads and resources for purposes of determining Washington rates in this proceeding. It is clear that resources within the Company's Western control area provide direct benefits to Washington.

Q. Is it possible for a facility located in the Eastern control area to provide indirect benefits to Washington?

A. Yes. The Commission recognizes that not all costs and benefits need to be direct in order for the costs and benefits to be allocated to Washington. In Paragraph 51 of Order 04 in the 2005 Rate Case, the Commission stated:

> Under either circumstance, the Company must demonstrate a quantifiable benefit to Washington ratepayers. When a facility is actually used to provide service, its costs and benefits can be readily identified and allocated appropriately. The same cannot be said for resources that do not provide direct service or only have occasional or potential value to Washington ratepayers. While such resources may still be compensable under our statutory scheme, they require more complex analysis, which must consider and quantify any indirect benefit sought to be recovered in rates.

Q. Is the WCA methodology capable of addressing such "indirect" benefits?

A. Yes. The WCA methodology is able to allocate the costs and benefits of resources which may provide "indirect" benefits to Washington. While the proposed WCA methodology begins with the allocation of Western control area resources only, it is flexible enough to allow for the future inclusion of other resources upon a showing by the Company that the costs and benefits are associated with direct or indirect service to Washington.

In other words, the WCA methodology recognizes that the Company's system is dynamic. In the future, the Company may acquire resources that serve one, or both, control areas. Or, the Company may acquire additional transmission resources which allow for power transfers not possible under the present system.

The WCA does not preclude such additional resources from being included in rates, so long as the Company can make the necessary showing that such resources provide direct or indirect benefits to Washington. This is consistent with the Commission's statement in Paragraphs 68 and 69 of Order 04 in the 2005 Rate Case:

> We find, however, that the Company must demonstrate tangible and quantifiable benefits to Washington of resources in the system before we will include the resources in rates. The test for including a resource in rates is not whether it is "needed, deliverable and least cost" but rather whether it provides quantifiable direct or indirect benefits to Washington commensurate with its cost.
>
> The Company can demonstrate this through historical system operation or modeling of the system showing that Eastside plant costs added to Washington rates would be offset by reductions to other cost categories (e.g., power costs), such that overall costs to Washington ratepayers would be no more than without the Eastside resources.

Q. How can such indirect benefits be established using the WCA methodology?

A. There are two ways. First, a party can propose such indirect benefits in a rate case or other relevant proceeding, and the Commission can decide if the resource in question meets the Commission's standard for including the resource in setting Washington rates.

Second, Staff proposes the Commission establish a Monitoring Committee. Ideally, this forum will allow for the consensus recommendations to the Commission regarding amendments to the WCA methodology. The Committee would consist of interested Washington parties. The Committee could make recommendations in subsequent rate cases or other relevant Commission proceedings.

Q. Has the Commission stated any requirements for a cost allocation method related to PacifiCorp's Western control area hydro resources?

A. Yes. In Paragraph 70 of the Commission's Order 04 in the 2005 Rate Case, the Commission said:

> We expect the Company to include the full value of hydroelectric resources in the Western control area in any inter-jurisdictional cost allocation model it develops for Washington.

Q. Does the WCA methodology comply with the Commission's "full value" requirement?

A. Yes. The WCA methodology assigns costs and benefits of Western control area hydroelectric resources only to those jurisdictions in the Western control area, including Washington.

Q. Does the WCA methodology allow for the efficient implementation of a power cost adjustment mechanism?

A. Yes. Variable costs and benefits of the resources contained in the WCA can readily be tracked for purposes of implementing a PCAM.

However, at present, it is necessary to use what I call a "pseudo actual" methodology for some costs and benefits. Because the Company's accounting system does not generally distinguish between day-to-day system transactions on a control area basis, it is necessary to use representative numbers where actual numbers are not available.

Q. The Commission stated in Paragraph 70 of Order 04 in the 2005 Rate Case, that the Hybrid Model identified in that case "holds promise." Is the WCA methodology appropriate in light of that statement?

A. Yes. The WCA meets the needs of Washington, and it meets the Commission's allocation method requirements. It is therefore unnecessary to adopt a Hybrid Model of the sort being evaluated in other jurisdictions.

In other words, the WCA methodology provides a reasonable basis on which to determine rates. It is easy to understand, efficient to implement, and flexible. These characteristics are important in order to have a dynamic model that addresses ongoing changes in long-term purchase and sales contracts, new resource additions, and system balancing requirements under a variety of water year conditions.

In addition, in my opinion, the Hybrid Model is one step down the "slippery-slope" of adding significant complexity for the sake of identifying and capturing a limited level of potential incremental costs and benefits.

In short, the WCA methodology meets the present needs of Washington and the Company, and it satisfies the Commission's requirements of an acceptable allocation model, without the additional burden and conflicts associated with the Hybrid Model.

Q. Please elaborate on your recommendation that the Commission order a set review period for the WCA methodology.

A. The WCA methodology is anticipated to be a permanent allocation solution for Washington and the Company. However, the Commission should establish a formal five-year review period to provide a specific, known period in which the WCA methodology can be formally evaluated and reviewed by all interested parties.

The Company should initiate the process with a report addressing the effectiveness of the WCA methodology as a tool for setting electric service rates in Washington.

The five-year evaluation period balances the need to have a methodology in place for a sufficient period of time, and the timeliness of any evaluation of the methodology.

The evaluation period does not mean that no changes can be made to the WCA methodology after that time. Of course, the Commission retains its discretion to require the use of a different methodology, or make changes to the WCA in any appropriate proceeding.

Q. Is the WCA methodology based on how the Company operated its system before it merged with Utah Power and Light Company?

A. No, and it should not be. The WCA methodology is based on the manner in which the Company's system is operated today (e.g., Eastern and Western control areas with limited interconnection capability). The WCA methodology does not take into consideration historical configurations of the Company either pre- or post-Pacific Power and Utah Power merger.

Consequently, there are certain resources whose costs and benefits may have been historically included in developing Washington rates, but are not initially included in the WCA methodology as proposed. However, the WCA methodology allows for their inclusion for purposes of determining Washington rates, if they meet the Commission's standards for allocating resources to Washington.

Q. Is the WCA methodology perfect?

A. No. However, I believe there is no perfect methodology for allocating the costs and benefits associated with providing electric service by a multi-jurisdictional electric utility. The WCA methodology does, on balance, result in a reasonable estimate of the fixed and variable operating costs and benefits associated with the portfolio of resources directly serving Washington under a variety of water conditions for purposes of setting rates.

For example, the WCA methodology may not capture all of the costs and benefits of the Company's system operations. By initially isolating the Western control area resources, the model used for the methodology may not capture some incremental costs and benefits that are present through the Company's operation of the two separate control areas, even under the current limited transfer capability between control areas. However, it is my opinion that these short-comings are minimal compared to the benefits of having a workable methodology.

Finally, the WCA methodology allows the flexibility to amend the model or to identify and include additional costs of resources that may indirectly serve Washington and have been determined to have positive benefits. In fact, Staff's second modification to the Company's model, the addition of a market "bubble," recognizes the possibility of system balancing transactions to the Eastern control area and it is an example of how the WCA methodology can be modified.

In sum, the WCA methodology represents a balanced and workable solution to a long standing roadblock for determining an appropriate level of the costs PacifiCorp incurs to serve Washington. The WCA methodology also provides an acceptable platform for use in implementing a power cost adjustment mechanism for the Company.

B. Net Power Supply Expense Adjustments 5.4 and 5.5

1. Summary of Staff's power supply expense adjustments

Q. Please summarize Staff's recommendations regarding the appropriate level of net power supply expense for determining rates for electric service for PacifiCorp in Washington.

A. Staff recommends five changes to the Company's proposed net power supply expenses, including incorporating the results on net power supply expense of the new market "bubble" modification to the WCA methodology, which I discussed earlier.

Four changes relate to Adjustment 5.4, Miscellaneous Power Supply. Three of these changes relate to corrections and a load update: 1) A correction to remove certain transmission costs from the Western control area; 2) A correction to remove costs associated with spinning and regulating reserve requirements for the Eastern control area; and 3) Use of a load forecast that matches the power supply rate year. The fourth change relates to the "Eastern Market Modification": 4) The impact of Staff's proposed change to the WCA methodology to take into account certain sales to the Eastern Control Area.

The fifth change relates to Adjustment 5.6, Water Year Adjustment: 5) A water year adjustment that eliminates extreme water years from the calculation of a base level of net power supply costs in anticipation of implementing a PCAM.

Q. Have you prepared an exhibit that summarizes the effect on net power supply expense of these five changes?

A. Yes. The effect on net power supply expense is summarized in my Exhibit ___ (APB-3). I combined the first three changes listed above with the effect of Staff's recommended Eastern market "bubble" modification to the WCA methodology, and ran them through the GRID model and the subsequent net power supply calculation together as a group. As shown on lines 3 and 4 of my exhibit, collectively, these changes result in a $1,527,176 decrease in base level net power supply expense for Washington customers.[1] Of this amount, $480,136 is due to the first three changes I

[1] These changes implemented in Staff witness Mr. Schooley's Exhibit ___ (TES-2), page 10, Adjustment 5.4, Misc. Power Supply.

listed above, and $1,047,040 is due to adding the potential for Eastern control area sales to the WCA methodology.

The effect of the Adjustment 5.6, Staff's Water Year Adjustment, is an additional decrease in Washington base level net power supply expense of $1,540,683. This adjustment is a necessary part of Staff's support for the adoption of a PCAM for PacifiCorp.

Altogether, these adjustments lower Washington's overall base level net power supply expense by $3,067,859 to $92,385,102 from the $95,452,961 amount proposed by the Company in its direct case. This lower net power supply expense level also forms the base level net power supply expense for purposes of determining deferrals or credits under Staff's proposed PCAM.

2. Adjustment 5.4, Miscellaneous Power Supply

Q. Please elaborate on the first two changes in Adjustment 5.4, which you identified as "corrections" to the Company's net power supply calculations.

A. First, the Company's calculation of net power supply expense for Washington incorrectly included transmission cost forecasts related to certain transmission service outside the Western control area. Consequently, Staff removed costs related to service identified as "Mead/Phoenix" and "Sierra Pacific" from the Western control area model, as well as the costs associated with an Idaho Power contract providing dynamic overlay support.

Second, Staff removed costs associated with a GRID modeling error, in which the Company had mistakenly included in Western control area costs amounts associated with spinning reserve and regulating reserve requirements for the Eastern control area.

The Company has acknowledged these corrections in its responses to intervenor and Staff data requests.

Q. Please describe the third change in Adjustment 5.4, related to the load forecast update.

A. As filed by the Company, the retail load used as input into the GRID model for purposes of deriving net power supply expense represents Company loads through March 31, 2006. This third change reflects my use of an updated load forecast that more closely matches the loads with the resources and other input into the GRID model for purposes of determining the base level of net power supply expense.

The Company expended significant effort to develop this update. The Company has developed no further updates because the Company does not anticipate a rate year beginning later than April 2008. However, a further update may be possible as part of a compliance filing by the Company to be consistent with the actual rate year which may be adopted by the Commission.

3. Adjustment 5.6, Water Year Adjustment

Q. What is the purpose of Staff's Water Year Adjustment?

A. This adjustment removes the net power supply expense uncertainty associated with extreme, or "outlier" water years from the calculation of the base level net power supply costs, which are then used to support the implementation of a PCAM for the Company.

Q. Why is it appropriate to make this adjustment?

A. In prior proceedings, the Company filed its proposed net power supply costs based on running the power cost models over a number of water years and then calculating a "normalized" level of net power supply expense for purposes of ratemaking. The number of water years and their timing has been a contentious issue in many past rate proceedings.

In this filing, the Company is using a rolling 40-year average of the most recently available hydro-electric data. This approach would be acceptable, if the Company where not also proposing a power cost adjustment mechanism. In other words, the Company's calculation of normalized net power supply expense using a broad number of water year conditions is entirely appropriate in an environment of limited general rate case filings that has been typical of the past. Rates were set using conditions reflecting a collective probability that a range of actual power supply expense levels would be experienced over time, and thus actual under-recovery of costs in some years would be balanced by over-recovery in others.

However, the implementation of a power cost adjustment mechanism virtually eliminates the need for such complex and controversial methods for determining an appropriate level of net power supply expenses for ratemaking purposes.

In short, in a power cost adjustment mechanism environment, net power supply expense normalization needs to be aligned with the implementation of a power cost adjustment mechanism.

Q. Have you prepared an exhibit showing the calculation of the water year adjustment?

A. Yes. The calculation of this adjustment is shown in my Exhibit ___ (APB-4). I began with the forty years of water data used by the Company. I then tabulated the total annual generation of the hydro-electric facilities as determined by the Company's VISTA model for each of the water years. Then I calculated a one standard deviation on each side of the normal distribution of water year generation.

For purposes of determining a base level of net power supply expense, I then mechanically applied this plus and minus one standard deviation "filter" to the forty water years of generation, thereby removing from the calculation those years in which total annual generation was below or above the band. The net power supply expense amounts related to the remaining water years were then used to determine the appropriate normalized base level net power supply expense for purposes of determining the overall revenue requirements in this case.

Q. What was the basis for choosing a one standard deviation band for "filtering" the 40 year average water year generation data?

A. Applying a plus and minus one standard deviation band to the mean values was a straightforward way to calculate and apply to the normally distributed data. It clearly eliminates the outlier water years when extreme water conditions exist, both favorable and unfavorable, resulting in net power supply expenses that are the most uncertain.

I made no attempt to balance the years removed by the filter between extreme dry or wet years. Costs associated with the filtered years are not used to set rates. If the conditions in the filtered years actually occurred, the associated incremental costs would be recovered or rebated under both the Staff's and the Company's proposed PCAMs. Neither did I attempt to balance the number of remaining years actually used for ratemaking purposes. Any attempt to base a filter on balancing of the number of wet or dry years using a median approach fails to recognize that it is balancing the variability in the amount of generation available that is important, not balancing the actual number of water years that are wet or dry.

For example, it may take several years of generation associated with good water years to balance the effect on generation of a particularly bad water year, even within the range of water years that are being used to determine net power supply expenses. Thus, a mean-based approach is more appropriate.

Q. If extreme, or "outlier," water years and their associated net power supply expense levels are removed from the rate setting process, is the Company able

to recover, or ratepayers receive the benefits of, the costs the Company incurs in such years?

A. Yes. These incremental costs are simply not being recovered as part of overall revenue requirements. This is reasonable because depending on the final structure of the PCAM, customers will pay a portion of these costs and receive a portion of the benefits, when and if they actually occur.

Q. Can this adjustment form the basis for any structure of the proposed PCAM the Commission decides to approve?

A. Yes. As I discussed earlier in my testimony, this adjustment supports the implementation of a PCAM for PacifiCorp. For purposes of PCAM design, the relative size of the standard deviation can be a starting point for developing the appropriate sharing bands contained in any PCAM structure. However, I emphasize that this should be the basis for a "starting point" in that analysis. There are other important considerations that go into determining an appropriate PCAM.

Q. What is the effect on net power supply expense of your water year adjustment?

A. As shown on the last line of my Exhibit ___ (APB- 3), the water year adjustment results in a reduction in Washington base level net power supply expense of $1,540,683.[2]

[2] This adjustment is implemented in Staff witness Mr. Schooley's Exhibit ___ (TES-2), page 10, Adjustment 5.6, Water Year Adjustment.

C. **Power Cost Adjustment Mechanism**

Q. Have you reviewed the Company's testimony regarding its proposed power cost adjustment mechanism or "PCAM"?

A. Yes. The Company proposes a PCAM similar to the mechanism the Commission has authorized for Avista Corp. ("Avista"), called the "ERM." Mr. Widmer describes the mechanics of the Company's proposal in detail in Exhibit ___ (MTW-1T) beginning at 26. The Company has not proposed an explicit cost of equity adjustment related to the implementation of the PCAM.

Q. Did Staff discuss the power cost adjustment mechanism with the Company?

A. Yes. As I described earlier, and as discussed in the testimony of Mr. Widmer (Exhibit___ (MTW-1T) at 26), there were discussions between the Company, Staff, and intervenors as the Commission requested in its orders in the 2005 Rate Case. I believe these discussions between the Company and the participating parties were beneficial in focusing the Company's efforts for purposes of their filing in this proceeding.

1. Summary of Staff's recommendations

Q. Please summarize Staff's recommendations regarding a PCAM for PacifiCorp.

A. Staff recommends that the Commission approve a PCAM for use by the Company beginning September 1, 2007. Staff also recommends that the Commission adopt a

PCAM that reflects the modifications to the Company's PCAM that I describe later in my testimony. Finally, Staff recommends the Commission accept Staff's adjustment to cost of capital for the impact of the PCAM. Staff witness Mr. Elgin is responsible for that adjustment.

Q. What PCAM annual period should the Commission authorize?

A. The Commission should use a PCAM period of July 1 through June 30, with the annual review filing date of September 1. This is different than the calendar year measurement proposed by the Company in Exhibit ___ (MTW-1T) at 29.

Q. Why is a July 1 through June 30 PCAM annual period appropriate?

A. This period sets the PCAM filing and review period to a different calendar date than the power cost adjustment mechanisms of the other electric utilities regulated by the Commission: Puget Sound Energy and Avista Corp. This will aid the Commission and the parties because three PCAM-type reviews will not be going on at the same time.

In addition, this time period better aligns the PCAM and the effects of annual water conditions for purposes of tracking actual costs. Finally, the treatment of the initial PCAM period can be handled by setting the initial period only as September 1, 2007 through June 30, 2008. In the event, if new rates are established in this case, and the PCAM is implemented beginning at an early date in 2007, this period can be adjusted at the front end.

2. Compliance with Commission standards for PCAMs

Q. What standards has the Commission stated for implementing a PCAM?

A. In the Commission's recent order in the 2005 Rate Case for PacifiCorp, at pages 34-35, paragraph 91, the Commission summarized these standards as follows (footnotes omitted):

- The purpose is to recognize variability in the cost of operating *existing* power supply resources as a result of abnormal weather conditions that are out of a utility's control. Ratepayers understand the connection between weather and rates;
- Power cost adjustment mechanisms are *short-run* accounting procedures to address *short-run* cost changes resulting from unusual weather;
- It is not appropriate to include new resources in a power cost adjustment mechanism. New resources must be considered in general rate cases or power cost only rate cases;
- Ratepayers should receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for ratepayers and earnings stability for stockholders, and;
- Power cost adjustment mechanisms should not interfere with least cost planning, conservation or other regulatory goals.

Q. How does Staff's proposed PCAM comply with the Commission's standard that "[t]he purpose is to recognize variability in the cost of operating *existing* power supply resources as a result of abnormal weather conditions that are out of a utility's control. Ratepayers understand the connection between weather and rates?"

A. The Staff's proposed PCAM tracks the variability in net power supply expenses resulting from certain power supply expense components that change as the result of hydro-electric generation conditions. In the PCAM, actual costs and benefits related to existing resources are compared to those that are used to set base power supply expense levels.

In addition, the sharing bands I have proposed are based on an analysis of hydro-electric generation variability.

Q. Does the Company's proposed PCAM also comply with this standard?

A. Yes, with one exception. The Company's proposal to use the PCAM to recover fixed production costs does not comply with this standard. Staff's proposal removes this component.

Q. How does Staff's proposed PCAM comply with the Commission's standard that "[p]ower cost adjustment mechanisms are *short-run* accounting procedures to address *short-run* cost changes resulting from unusual weather?"

A. The Staff's proposed PCAM tracks monthly changes in certain actual power supply cost components as compared to the levels used to set base rates for the Company. These changes are then analyzed on an annual cumulative basis for purposes of determining potential deferrals or rebates. The process starts over as a new measurement period begins.

Q. Does the Company's proposed PCAM also comply with this standard?

A. Yes.

Q. How does Staff's proposed PCAM comply with the Commission's standard that "[i]t is not appropriate to include new resources in a power cost adjustment mechanism. New resources must be considered in general rate cases or power cost only rate cases?"

A. Staff's proposed PCAM contains no component related to recovery of new resources. I removed the Company's proposed fixed production cost component of the PCAM, recognizing that the recovery of fixed production costs should take place in a general rate case or a power cost only proceeding.

However, I support the Company's proposal to limit the inclusion of variable costs associated with new long-term resources or wholesale transactions, to those instances in which the resource or transaction has a term less than two years and is under 50 average MegaWatts. This feature removes the effect on variable net power supply expenses of larger, long-term resources pending a rate case or other, power cost only proceeding.

Q. Does the Company's proposed PCAM also comply with this standard?

A. No. The Company's proposed PCAM contains a fixed production cost recovery component which would include the cost of new facilities.

Q. How does Staff's proposed PCAM comply with the Commission's standard that "[r]atepayers should receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for ratepayers and earnings stability for stockholders?"

A. As I mentioned earlier, Staff is proposing an adjustment to cost of capital related to the Staff's proposed PCAM. Staff witness Mr. Elgin testifies regarding this issue.

Q. Does the Company's proposed PCAM also comply with this standard?

A. No. The Company did not propose any cost of capital reduction associated with its proposed PCAM. Again, Mr. Elgin is responsible for this issue.

Q. How does Staff's proposed PCAM comply with the Commission's standard that "[p]ower cost adjustment mechanisms should not interfere with least cost planning, conservation or other regulatory goals?"

A. The PCAM does not impede the Company's ability to meet least cost planning, conservation or other regulatory goals. In fact, the PCAM, in conjunction with a general rate case or other power cost only proceeding, enhances the ability of the Company to address the timely treatment of costs and benefits available through least cost planning, conservation, or other regulatory actions.

Q. Does the Company's proposed PCAM also comply with this standard?

A. Yes.

3. Is a PCAM appropriate for PacifiCorp?

Q. How do you analyze the issue whether the Commission should authorize a PCAM for PacifiCorp in this proceeding?

A. My analysis of this issue is in two parts. First, I discuss whether PacifiCorp should have a power cost adjustment mechanism, and second, if so, what should be the structure of such a mechanism?

Q. As a threshold matter, is a PCAM consistent with and appropriate under the WCA methodology?

A. Yes. As I explained earlier, a PCAM in some form would be appropriate if a Western control area allocation method scheme such as the WCA is adopted. Washington rates are being determined, to a large degree, based on Western control area resources that experience significant variability in their costs, due to factors the Company does not control. This cost variability can result in both favorable and unfavorable effects on Washington's actual net power supply expense. The PCAM allows for these costs and benefits to be passed through to customers in a fair and appropriate manner.

Q. Does PacifiCorp have a significant degree of power cost variability?

A. Yes. A significant amount of the Company's net power supply costs are variable and beyond Company control, because water conditions in the region are a function of nature and can vary significantly from year to year, and even within a single year.

As a result of this variability in water conditions, the Company has no long-term control of hydro-electric generation from the hydro facilities it owns, nor does the Company control the amount of generation that is obtainable on an annual basis from its Mid-C contracts and other agreements.

Similarly, the Company has no control of either the sales prices or purchase prices related to economy market energy transactions it needs to make in order to address hydro-generation variability or short-term changes in customer load.

Finally, the Company has only limited control over some other power supply related variable costs such as gas prices, coal prices, and certain purchase and sales contract rates, as its portfolio changes over time.

Of course, even given this lack of Company control or the Company having only a limited amount of control, the Commission needs to review all of these variable costs prior to their ultimate recovery from ratepayers, whatever PCAM design is authorized.

Q. Has the Company estimated the degree of variability of net power supply expenses that it can experience?

A. Yes. The Company offers a rather simple analysis, estimating that net power costs in the Western control area could swing by as much as $215 million, or approximately $48 million for Washington customers, due only to historical variations in hydro generation. *See Mr. Widmer's Exhibit ___ (MTW-4) at 27.* If this figure is accurate, this presents very significant power cost variability, considering that the Company's total base level net power supply expense for the Western control area using the WCA methodology is approximately $417 million.

Q. Does Staff concur in the Company's estimate?

A. The Company's estimate is only one way of determining the variability of power supply costs. The Company's response to Staff Data Request 64 provides another analysis specifically applicable to Washington, rather than the Western control area as a whole.

In this response, the Company analyzed the effect on net power supply expense comparing the "best" and "worst" water years as run though the Company's GRID model. The analysis shows that net power cost expense can swing approximately $26.6 million for Washington.

This $26.6 million swing reflects the total swing of net power supply costs before any sharing between investors and ratepayers of any excess power costs. Potentially, this $26.6 million swing could also increase due to additional wholesale market price changes under extreme water conditions.

Regardless, $26.6 million still reflects significant variability. That amount is about 30 percent of the approximately $95 million in the Company's proposed Washington base level net power supply costs.

Q. Does the level of net power supply expense variation that you have described support the implementation of a PCAM for PacifiCorp?

A. Yes. As I described, the Company is subject to significant variability in net power supply expenses, and this variability is beyond the Company's control. These variations can be best addressed through a PCAM rather than through the more uncertain normalized net power supply cost methodology.

However, the Commission should be aware that these examples and amounts of variability I have described are "extreme" examples, showing the effects of the most variable of all costs. Long-term water year conditions generally have a normal distribution, meaning the extremes have a low probability to occur. Actual variability experienced in a typical year should be much lower, which will be further addressed in the design of sharing and dead bands contained in the PCAM. Also, as I explained earlier, Staff's water year adjustment has the effect of setting base rates using a narrower band of water year conditions.

Finally, it is helpful to describe what companies may do in the absence of a PCAM. As Staff witness Mr. Elgin describes, when power costs become much higher than the level included in setting rates, and the utility's financial condition is threatened, the Commission has granted deferral of power costs or granted what is called "interim" rate relief. These are "built in" processes designed to address extreme variability in power supply, or other costs.

In past years, regulated electric utility companies in this state have filed for deferrals or interim rate relief to recovery excess costs associated with extreme water and market conditions. Implementing a PCAM will address these extreme cost occurrences without the added controversy of determining what is already included in base level power supply costs.

Q. Are there other reasons to implement a PCAM for Washington customers?

A. Yes. It is well known that in the Pacific Northwest, electric power costs are largely tied to water conditions, due to this region's reliance on hydro-electric generation.

Under a PCAM, electric customers will better experience that connection, both favorably and unfavorably, through rate changes.

A mechanism that provides this connection between rates and the variability of power costs due to water conditions and resources in the region should result in more appropriate price signals, and better align interests in the Pacific Northwest, including the effects of electric and water consumption under drought conditions.

4. *Structure of the PCAM*

a. **Overview**

Q. What PCAM design does PacifiCorp propose?

A. As described by Mr. Widmer in Exhibit ___ (MTW-1T), beginning on page 28, the Company' proposed PCAM has a dead band of $3 million. No power costs would be deferred in this band. The next band is a sharing band. Customers would pay 60% of the next $4.7 million (over $3 million up to $7.4 million) in excess power costs; the Company would absorb 40 percent. In the last band, or outer band, customers would pay 90 percent of all excess power costs above $7.4 million.

The Company also describes how it proposes to recover or rebate any accrued PCAM balances from or to customers.

Q. How does the Company's PCAM compare to Avista's PCAM?

A. Like Avista's PCAM, and other power cost adjustment mechanisms, PacifiCorp's PCAM is generally a comparison between authorized and actual variable power supply costs. The Company's proposed PCAM has a dead band, a series of sharing bands, and an adjustment for variances in actual retail load.

The Company's proposed PCAM also contains a component in which the variable costs associated with smaller, short-term new resources or contracts can be recovered, but variable costs associated with larger, longer-term resources are priced at market, until such costs are included in base rates through a general rate case process.

These are all features that are similar to Avista's Energy Recovery Mechanism (ERM).

However, the Company is also requesting the adoption of a fixed cost component of the PCAM, in which the Company recovers the annual variances between actual fixed production costs and production costs imbedded in rates. According to the Company, this component is included to provide a match between recovery of variable net power costs and fixed production costs. Avista's ERM has no such component.

Q. Is the Company's proposed PCAM appropriate?

A. Only partially. Staff proposes certain modifications that, in my opinion, are essential before the Commission should adopt a PCAM for PacifiCorp.

Q. Please identify Staff's proposed modifications to the Company's proposed PCAM.

A. I earlier discussed a change in the measurement year. I also propose changes to the sharing bands and the dead band. I recommend the Commission not adopt the Company's proposed fixed production cost component at this time, pending further development of that proposal by the Company within the boundaries of a general rate case or a power cost only proceeding. Finally, I recommend a change to the Company' proposal regarding how the PCAM balance is recovered from or rebated to customers, and I propose a monthly PCAM reporting requirement.

Q. What aspects of the Company's proposed PCAM should the Commission accept?

A. I recommend the Commission accept the Company's definition of variable net power costs for purposes of the PCAM deferral calculation. *See Mr. Widmer's direct testimony in Exhibit ___ (MTW-1T, at 29).* For purposes of this proceeding, I recommend the Commission accept the use of the GRID model to derive "adjusted" actual power costs for the PCAM. *Id. at 29-30.* However, I also recommend the Company explore internal accounting methods by which actual Western control area related transactions can be tracked for purposes of determining actual net power costs for use in calculating PCAM variations.

Next, I recommend the Commission accept the Company's proposed "retail revenue adjustment," which is the same adjustment used in Avista's ERM. *Id. at 30.* This adjustment is used to match the recovery of margin with actual retail loads. I also recommend the Commission accept the Company's proposed methodology for treating new long-term variable resource costs and wholesales transactions, with the size and term restrictions proposed by the Company. *Id. at 31*. This methodology allows for the timely recovery of the variable cost component of new resources.

Q. How should the Commission determine whether the PCAM is working as anticipated?

A. In addition to ongoing review as the PCAM is implemented, I recommend the Commission order the Company to make a specific PCAM review filing after the PCAM has been in place for 3 full years. In that future docket, the Company would provide testimony supporting the continued use of the PCAM as structured, or propose modifications. Other parties would respond to the filing with their own recommendations. The Commission used such a proceeding as part of the implementation of Avista's ERM.

b. Structure of the bands in the PCAM

Q. Please identify the dead band and sharing bands in Staff's proposed PCAM.

A. Staff recommends a PCAM with the following bands:

Dead band:	Zero to ±$4 million
50/50 sharing band:	Over ±$4 million to ±$10 million
90/10 sharing band:	Over ±$10 million

"90/10" sharing means customers would be responsible for 90 percent of the deferrals in this band, and the utility would be responsible for 10 percent.

Q. How does Staff's dead band of zero to plus or minus $4 million compare to the Company's proposed dead band?

A. The Company proposes a dead band of plus or minus $3 million.

Q. Why should the Commission adopt a $4 million dead band rather than a $3 million dead band?

A. The dead bands are typically established as a tool to allow the utility to manage some power supply risk without an immediate need to book deferrals or credits to be recovered from or rebated to customers. This feature helps to minimize the administrative burden of the PCAM, and limits its effect to those periods with a more substantial variation in power costs.

Staff's proposal to increase the size of the dead band to plus or minus $4 million is primarily in response to the Company's use of what I earlier described as "pseudo" actual net power costs for purposes of the PCAM. I believe that even with the best intentions, the use of a model to determine actual power costs (although a necessity for the Company in the near-term) is a cause for some concern. Increasing the dead band addresses that concern.

Q. How does Staff's initial sharing band compare to the Company's proposal?

A. Staff's initial sharing band goes from over $4 million to $10 million, plus or minus, with 50/50 sharing. The Company proposes an initial sharing band of over $3 million to $7.4 million, plus or minus, with 60/40 sharing. This means customers would be responsible for 60 percent of the dollars in this band, and the Company would be responsible for 40 percent.

Q. What is the basis for Staff's initial sharing band?

A. The initial sharing band is a transition from the dead band to the outer sharing band, so that there is not a "cliff" between a dead band and a 90 percent/10 percent customer/company sharing. By a "cliff" I mean going directly from no sharing in dead band, where the utility absorbs all of the costs, to the 90/10 sharing band, where utility absorb virtually none of the costs.

A PCAM design with such a "cliff" may provide the utility a reduced incentive to manage resource costs once the limit of the dead band is reached. Consequently, an intermediate band with equal sharing is appropriate.

Staff recommends the first sharing band contain 50/50 sharing. There is no obvious reason to depart from the 50 percent/50 percent customer/company sharing the Commission adopted in the Avista ERM, which has been implemented successfully. This percentage of sharing has been demonstrated to provide appropriate incentives for managing costs.

Q. How does Staff's outer sharing band compare to the Company's proposal?

A. Staff recommends an outer band of all dollars over $10 million, plus or minus, with the same 90/10 sharing as the Company's outer band. The Company proposes an outer sharing band of all dollars over $7.4 million, plus or minus, with 90/10 sharing. This means customers would be responsible for 90 percent of the all dollars in this band over $7.4 million, and the Company would be responsible for 10 percent.

Q. What is the basis for Staff's proposal for the outer sharing band?

A. Staff's proposal is based on my analysis of the Company's net power supply costs from the GRID model. The $10 million outer band with 90 percent/10 percent sharing is justified by the variability in net power supply costs used to set base level rates.

As I discussed earlier in my testimony, Staff is proposing a water year "filter" be used, in which the Company's base level net power supply expenses for purposes of setting rates are determined using water years with annual hydro-related generation, plus and minus one standard deviation from the mean. This results in rates being set using a narrower set of water years and net power cost variability than would be used absent a PCAM.

It follows from this proposal that an outer band that transfers the majority of the risks and benefits of extreme, or "outlier" water years to customers is appropriately set at plus or minus $10 million. I calculated this amount by applying the standard deviation energy amount used to make my earlier net power supply expense water year adjustment to an estimate of market prices.

This calculation estimates the variation in net power supply expense which has not been included in base rates and therefore should be recovered through the PCAM, with some risk sharing with the Company.

Q. What is the effect on the Company's exposure to variations in net power costs from Staff's proposed PCAM?

A. The Company's exposure to power cost variability, using my proposed dead band and sharing bands, would decrease compared to the current situation, but increase compared to the Company's proposal.

For example, under Staff's PCAM, a $20 million increase in actual net power costs would increase exposure to the Company from $6.02 million under the Company's PCAM to $8 million under Staff's. On the other hand, the Company would benefit by these same amounts with a $20 million decrease in net power costs.

c. The fixed cost component

Q. Please summarize the Company's proposed fixed cost component of the PCAM.

A. The Company is proposing to recover through the PCAM the changes between the fixed production costs included in determining rates in a general rate case, and the actual fixed production costs incurred by the Company during the PCAM measurement period. The Company wants to track operation and maintenance expense, depreciation and amortization expense, as well as authorized pre-tax return of net production and transmission plant. In addition, there would further adjustments to the fixed costs based on plant availability.

The Company claims that this PCAM feature will better match variable net power costs and fixed production costs. *(Mr. Widmer direct testimony, Exhibit ___ (MTW-1T) at 31).*

Q. What is the basis for Staff's recommendation that the proposed fixed production cost component of the PCAM not be adopted at this time?

A. The Company's proposal falls short in several areas. First, the proposal appears to be similar in intent to what PSE's Power Cost Only Rate Case ("PCORC") accomplishes, that is, it allows recovery through rates of changes in fixed production and transmission costs. However, the PCORC is a separate mechanism, independent of PSE's power cost adjustment mechanism. The PCORC does not create deferrals in a mechanism designed to track variable net power costs.

Second, including the tracking and deferral of fixed production or transmission costs in the PCAM is inconsistent with the Commission's PCAM policy, as I described earlier in my testimony.

Third, the Company's proposal is not complete. For example, the Company has proposed no procedural mechanism for addressing the prudence of new resource additions or other components that could form the basis for the actual fixed production and transmission costs. In addition, the mechanism is not consistent with the treatment of variable long-term resource costs and wholesale transactions that meet the size or term restrictions for including in the PCAM.

Finally, the Company has not adequately provided a reason for such a mechanism to be adopted as part of a PCAM in this proceeding. Although PacifiCorp explains that the mechanism will better align variable costs with fixed costs, PacifiCorp has not adequately demonstrated the need to burden a PCAM with such a mechanism.

Q. Is Staff sympathetic to the need to better match variable and fixed production and transmission costs, and benefits, in a timely manner?

A. Yes. Staff is also aware of the potential regulatory burden put on the Company with the passing of Initiative 937 in Washington, and the Company's desire to obtain timely recovery of costs associated with renewable resources the Company needs to acquire to comply with that initiative.

However, it is preferable for the Company to make a proposal separate from a PCAM to address the timely recovery of fixed costs, including the investment in Company-owned renewable resources and/or related transmission assets.

d. When PacifiCorp should collect or rebate PRAM balances in rates

Q. What is Staff's proposal for when PCAM balances should be recovered from or returned to customers?

A. The threshold balance for actually implementing a surcharge or rebate should be $6 million, rather than the Company's proposed $3 million. This higher threshold would allow for a better opportunity for subsequent PCAM periods to balance the variability in net power costs, as a subsequent favorable water year may bring any deferred balance from less favorable year back toward zero, and vice versa.

However, in order to maintain some relationship between potential deferrals under the PCAM, the Company should be required to develop a timely and forward-looking notification process by which customers can be informed of possible power cost ramifications related to expected hydro-generation conditions or other changes in variable power costs.

e. Monthly reports

Q. Does Staff have any other recommendations regarding PCAM implementation?

A. Yes. The Company should be required to submit to the Commission monthly reports detailing monthly PCAM deferral or credit balances, as well as a narrative description of what is causing the deferrals or credits. The Company should also provide copies of any long-term wholesale transactions entered into by the Company that are anticipated to be included in the PCAM, or other proceedings affecting Washington rates. This information is essential for the Commission to review the workings of the PCAM over time.

D. Resource Acquisition Prudence

Q. What Western control area long-term supply-side resources has the Company acquired since 2000?

A. Since 2000, the Company has acquired: 1) a power purchase agreement ("PPA") with Eurus Oregon Wind Power Development LLC ("Eurus"); 2) the Leaning Juniper 1 wind resource from Leaning Juniper Wind Power, LLC, ("Leaning Juniper 1"); and 3) the contracts that replace PacifiCorp's PPAs with Grant County Public Utility District ("Grant") associated with the Priest Rapids and Wanapum dams located on the Mid-Columbia (the "New Grant Contracts").

Q. Have you reviewed the testimony and exhibits provided by the Company in regard to the prudence of these new resource acquisitions?

A. Yes. Company witness Mr. Tallman provided testimony and exhibits addressing the prudence of these long-term supply-side resources for the purpose of being used and useful for Washington customers.

Q. What are Staff's recommendations in regard to these new resources?

A. I recommend that the Commission find that the Company has sufficiently demonstrated that the Eurus contract, the Leaning Juniper 1 project, and New Grant Contracts were prudently acquired by the Company, and they should be considered used and useful for Washington customers.

1. Eurus PPA

Q. Please describe your review with respect to the Eurus PPA.

A. The Eurus PPA is for up to 41 MW of wind generation capability. It has a term that expires 20 years following the project's commercial operation date, or December 22, 2023. The project is located in East Walla Walla Valley, Oregon. Under the PPA, PacifiCorp purchases the energy generated by the project, and the Energy Trust of Oregon ("Energy Trust") purchases the renewable resource attributes or "green tags." Above market costs are funded by the Energy Trust by virtue of their green tag purchase.

As explained in the direct testimony of Mr. Tallman (Exhibit ___ (MRT-1T) at 2-5), this project benefits Washington customers because it provides power at a cost equal to the expected long-term market price. Thus, PacifiCorp is able to purchase energy at market and have it delivered directly to that portion of PacifiCorp's transmission system that also serves end-use load in and around Walla Walla, Washington.

In addition, the energy associated with the Eurus PPA constitutes a renewable resource. As such, the resource does not create emissions when generating energy and provides PacifiCorp with valuable operational experience in preparation for satisfying any applicable renewable portfolio standards such as those contained in Initiative I-937, which was recently enacted in Washington.

In addition to evaluating the project's characteristics, I reviewed the Company's decision-making process for acquiring this resource. PacifiCorp's acquisition of the Eurus PPA is consistent with the Company's 2003 Integrated Resource Plan and its identification of wind resources as part of a prudent and balanced resource mix. This review supports my conclusion that the resource is a prudently incurred supply-side resource, used and useful for Washington customers.

2. Leaning Juniper 1

Q. Please describe your review of the Company's acquisition of the Leaning Juniper 1 project.

A. Leaning Juniper 1 is a wind resource located about three miles southwest of Arlington, Oregon. PacifiCorp owns the assets, all output and all interconnection rights (up to the project's 100.5 megawatts capability). As explained in the direct testimony of Mr. Tallman at pages 5-7, this resource benefits Washington customers because it is cost effective. R. Tallman's Exhibit ___ (MRT-3C) illustrates how the project is expected to lower both net power costs and revenue requirement over its design life.

In addition, as with the Eurus resource, this project provides benefits to Washington customers because it is a renewable resource which does not create emissions when generating energy and provides PacifiCorp with valuable operational experience in preparation for satisfaction of any applicable renewable portfolio standards that may be enacted including, for example, Initiative I-937 recently enacted in Washington.

I also reviewed the Company's decision-making process related to its acquisition of the Leaning Juniper 1 project. This acquisition is also consistent with the Company's 2003 Integrated Resource Plan, which identifies the need for renewable resources as part of a least-cost portfolio of resources. This review supports my conclusion that the resource is a prudently incurred supply-side resource, used and useful for Washington customers.

3. New Grant Contracts

Q. Please describe your review of the New Grant Contracts.

A. The New Grant Contracts are contracts that replace PacifiCorp's PPAs with Grant and are associated with the Priest Rapids and Wanapum dams located on the Mid-Columbia. The New Grant Contracts were offered to the Company as a result of renewal of Grant's license from the Federal Energy Regulatory Commission.

As explained in the direct testimony of Mr. Tallman at pages 8-13, these resources will benefit Washington customers because they are cost effective. Mr. Tallman's Exhibit ___ (MRT-4C) illustrates how the New Grant Contracts are estimated to have a beneficial net present value. The extension of these contracts has been anticipated and planned for in all integrated resource plan efforts carried out by the Company in recent years. Finally, my review of the decision-making process related to the acquisition of the New Grant Contracts supports my conclusion that the resource is a prudently incurred supply-side resource, used and useful for Washington customers.

Q. Does this complete your direct testimony?

A. Yes.