Exhibit No. ___CT (APB-1CT)
Docket UE-100749
Witness: Alan P. Buckley
REDACTED VERSION

BEFORE THE WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-100749

TESTIMONY OF

Alan P. Buckley

STAFF OF WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Power Supply

October 5, 2010

CONFIDENTIAL PER PROTECTIVE ORDER
REDACTED VERSION

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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 The Richard Hemstad Building, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504. My e-email address is abuckley@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission ("UTC") 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 UTC.

Q. How long have you been employed by the Commission?

A. I have been employed by the UTC since 1993.

Q. Would you please state your educational and professional background?

A. I received a Bachelor of Science 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. I was next 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 the Bonneville Power Administration ("BPA") and the Western Area Power Administration.

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

II. SCOPE AND ORGANIZATION OF TESTIMONY

Q. What is the purpose of your testimony?

A. The principle purpose of my testimony is to address the proposed pro forma normalized net power costs presented in PacifiCorp's ("the Company's") General Rate Case filed on May 4, 2010.

The Company's proposed pro-forma normalized net power costs in this proceeding are approximately $17.5 million higher than the settled level from the Company's 2009 general rate case, on a Washington-allocated basis. In my Exhibit No. ___ (APB-2), I provide a summary of my recommended adjustments to the Company's proposed pro forma normalized net power costs at the expense level.

The results of these adjustments at the revenue requirements level are reflected in Staff witness Foisy's Exhibit No. ___ (MDF-2).

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is divided into two sections. In Section III, I summarize my recommended adjustments to the Company's proposed pro-forma normalized net power costs, including transmission related costs. In Section IV, I explain the basis for each adjustment and describe the method of calculating the adjustment amount.

III. SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize your recommended adjustments to the Company's proposed pro forma normalized net power costs.

A. I propose adjustments to several items related to the Company's proposed pro forma normalized net power costs – some are included in the Company's filing and some are not. I address the Company's treatment of arbitrage transaction margins; the SCL Stateline and SMUD contracts; the transmission expenses associated with Colstrip, the DC intertie, and other PACE related costs; various wind integration costs; the effects of extended Colstrip outages on model inputs; certain Jim Bridger fuel related costs; and updated gas price forecasts. I explain each of these acronyms and adjustments later in my testimony.

I identify each of these adjustments in my Exhibit No. ___ (APB-2), with the corresponding estimated expense level adjustment. The total expense level adjustment to Washington pro forma normalized net power costs is $5,292,148. These adjustments reduce Washington allocated net power costs to approximately $123.4 million, as compared to the Company's direct case of approximately $128.9 million.

Q. You state the amounts shown on your Exhibit No. ___ (APB-2) are "estimated" expense level adjustments. Can you please explain?

A. Yes. The amounts shown are estimates only, for two reasons. First, I made each expense level calculation in isolation of the other adjustments. When running power supply models, it is typical that changes to one parameter may result in changes to other parameters as the system is "re-dispatched". Consequently, to ascertain the combined effect of all the adjustments, one would have to carry out a normalized power supply model run incorporating all of the Commission-accepted adjustments.

Secondly, the amounts shown on my Exhibit No. ___ (APB-2) are based on calculations done outside the GRID model. Staff was not able to carry out GRID model runs to derive the expense levels of the recommended adjustments. This is more an issue for those adjustments related to basic GRID model input assumptions, such as the Colstrip outage adjustment and SMUD contract shaping, but not necessarily an issue for those "non-dispatch model" issues such as transmission expenses and wind integration costs.

As part of my testimony, I recommend the Commission order the Company to carry out the appropriate GRID model runs including any Commission- accepted adjustments, as part of the Company's rate case compliance filing. This will provide the appropriate assurances that the effect of accepted adjustments is captured for ratemaking purposes.

Finally, it is my understanding that the ICNU power supply witness, Mr. Faulkenburg, has based similar recommended adjustments on actual modeled GRID runs, made possible by his long-standing and ongoing familiarity with the Company's GRID model in other jurisdictions. The Commission may wish to consider these realities when reviewing the effect of individual adjustments.

VI. NET POWER COST ADJUSTMENTS

A. Arbitrage Sales Margins

Q. What is the context of your first adjustment, labeled "Arbitrage Sales Margins" in Exhibit No. ___ (APB-2)?

A. PacifiCorp owns an extensive transportation system, both within its West Control Area and its East Control Area. Ratepayers in Washington pay the costs associated with approximately twenty percent of the West Control Area (WCA) transmission system under the WCA allocation model. Utilities regularly use these assets to carry out various transactions, both energy-related and solely transmission-related, in order to decrease overall net power costs to customers by creating additional revenue sources.

On the energy side, transactions typically take the form of both buy/sell arbitrage and energy trading opportunities. Typically, arbitrage transactions are short-term, low, or no risk, transactions where the Company takes advantage of its transmission system to buy energy at one delivery point and sell at another, making a relatively small profit on the transaction. Trading transactions, on the other hand, occur when the Company takes what may be a longer term position on energy purchases or sales, and these transactions may not be related to any specific transmission delivery point.

Q. What is the issue regarding these transactions?

A. The issue in this case is that the Company includes no arbitrage or trading revenues in its determination of normalized net power costs. In using the GRID model, the Company incorporates only system balancing transactions into normalized net power costs. In addition, the Company includes longer-term purchase and sales transactions in the model. However, the Company neglected to include any net revenues from short-term arbitrage or trading transactions.

Q. Do the ratepayers of the other Washington regulated electric utilities benefit from short-term arbitrage or trading transactions those utilities undertake using their respective transmission systems?

A. Yes. Avista and Puget Sound Energy capture the net revenues from these short-term arbitrage or trading transactions through their power cost adjustment mechanisms.

Q. Should PacifiCorp's ratepayers benefit from arbitrage and trading transactions too?

A. Yes. Although PacifiCorp does not have a power cost adjustment mechanism in this state, the Commission can and should normalize net revenues from these transactions in this case, or average them over a number of years and add them as out-of-model revenue for determining normalized net power costs.

Q. Does PacifiCorp carry out short-term arbitrage and trading transaction in the West Control Area?

A. Yes. [redacted]:

Table 1

Year	Buys		Sells		Net	
	Total $	Total MWh	Total $	Total MWh	Total $	Total MWh
[redacted]						

This information provides telling evidence that PacifiCorp is benefiting from these types of transactions and the Commission should include significant net revenues in its determination of normalized net power costs in order for ratepayers to obtain the appropriate benefits from the transmission costs they pay for in rates.

Q. How did you calculate your proposed adjustment?

A. I calculated a revenue adjustment related to arbitrage transactions by averaging the net revenues over the four years of data provided in the Company's response to ICNU Data Request 1.3. I recommend an adjustment to normalized net power costs equal to 90 percent of that four-year average, recognizing a 10 percent Company "sharing" of profits in order to maintain incentives for the Company to continue to maximize the use of its transmission system. This sharing also recognizes that the power cost adjustment mechanisms of Avista and Puget Sound Energy effectively include some amount of sharing for additional revenue generation sources. The calculation is simply 90 percent of the 4-year average shown in Table 1 above.

Q. Are you proposing an adjustment related to trading transactions in addition to short-term arbitrage transactions?

A. No. The trading transactions appear to be less regular than arbitrage transactions and the profits are more speculative. In proposing no specific adjustment for trading transactions, I recognize the Company, for the present, should benefit from the revenues associated with trading transactions, as well as be at risk for any losses. However, if and when the parties consider proposing a power cost adjustment mechanisms for PacifiCorp in the future, they may wish to explore including these trading transactions.

Q. What is the amount of your proposed Arbitrage Sales Margin adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment is $ 2,377,437 for the total West Control Area, or $527,315 million for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level.

B. SCL Stateline Contract

Q. Your next adjustment is labeled "SCL Stateline Contract" in Exhibit No. ___ (APB-2). Please explain the context of this adjustment.

A. The SCL Stateline adjustment is related to a contract between the PacifiCorp and Seattle City Light ("SCL"), in which the Company provides storage and integration services for SCL's Stateline wind farm. Under the exchange portion of the contract, the Company takes delivery of energy from the wind farm, and within two months, must return the energy to SCL. The contract terminates on December 31, 2011. To be precise, the delivery of what is called "storage" energy ends on December 31, 2011, nut the delivery of what is called "scheduled" energy does not end until February 29, 2012. Over time, the delivery and return of energy would be expected to even out.

Q. What is the issue?

A. The issue is that the delivery and return of energy do not match up with the months of the proposed rate year for rate making purposes in this proceeding, due in part to the termination of the contract. The mismatch can be seen in the monthly energy amounts shown in the confidential workpapers of Company witness Duvall for the SCL Stateline contract. The workpapers indicate a significant imbalance over the 12-month rate year period.

In addition, this contract does not appear to have been extended or renewed, so including it in rates beyond the contract termination date would not add to any mismatch between costs and rates unless new rates were established at that time.

Q. How should the Commission treat the SCL Stateline Contract for ratemaking purposes?

A. The most appropriate ratemaking treatment to address this contract that terminates during the rate year would be for the Commission to eliminate completely the exchange, as the Company has modeled it, from the GRID model. This would eliminate both the imbalance issue and the termination of the contract. However, for purposes of my testimony, the effect can also be estimated by making an adjustment equal to the 12-month energy imbalance shown in the Company's workpapers. In the event the contract is extended, the treatment for ratemaking should reflect a "no harm" standard for the transaction, with no energy imbalance reflected in GRID.

Q. How did you calculate your adjustment?

A. My Confidential Exhibit No. ___ (APB-3C) shows the total energy imbalance as represented in the Company's confidential workpaper marked UE-10-_Duvall Conf Workpaper 7 ConfidentialperWAC48007160(PACMay2010).xlsm NPC, page 5 of 10. I calculate an adjustment by adding back the total 12-month imbalance energy to the months of January and February 2012. I then calculate an adjustment based on the average forward energy price for January and February of 2012, which reflect the fact that if energy were being returned during those months, the net power costs would be reduced by the adjusted amount. This calculation is shown in Exhibit No. ___ (APB-3C).

Q. What is the amount of your proposed SCL Stateline Contract adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment is $2,125,412 for the total West Control Area, or $471,416 for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level.

C. SMUD Contract Shaping

Q. Your next adjustment is labeled "SMUD Contract Shaping" in Exhibit No. __ (APB-2). Please explain the context of this adjustment.

A. This contract is a sale for resale contract between PacifiCorp and the Sacramento Municipal Utility District (SMUD). PacifiCorp models the SMUD contract in GRID assuming the highest cost to PacifiCorp. This can be best illustrated by an examination of the Company's monthly net power cost analysis summarized in the confidential workpaper marked UE-10-_Duvall Conf Workpaper 7 ConfidentialperWAC48007160(PACMay2010).xlsm NPC, page 4 of 10.

The Company's modeling of the contract in GRID results in no deliveries to SMUD in the months of April, May, and June. These months are the traditional "low-cost" months for regional utilities, which means if SMUD where to actually take energy during these months under the contract, the cost to PacifiCorp would be less and the Company's normalized net power costs reduced.

Q. From SMUD's perspective, what are the preferred deliveries under this contract?

A. The best use of the energy deliveries from SMUD's perspective may be the result of differing weather and load patterns, planned maintenance outages of SMUD's generating resources, transmission issues, or other least cost decisions on the part of SMUD.

Q. How do the actual historical deliveries under the SMUD contract compare with how PacifiCorp models deliveries under that contract?

A. The actual historical deliveries by PacifiCorp to SMUD under this contract show a different pattern than the GRID model assumptions. As I mentioned, in GRID, PacifiCorp assumes significant deliveries to SMUD during April, May, and June and no deliveries under the regular SMUD contract during the months of October through December. I obtained the PacifiCorp's 2006 through 2009 actual monthly sales to SMUD from the Company's response to ICNU Data Request 1.7(d) which show that in fact, PacifiCorp makes significant deliveries to SMUD in the lower cost months of April through June.

Q. What adjustment is appropriate for the SMUD contract?

A. The impact of the SMUD contract should be adjusted to reflect a more accurate modeling, to better reflect actual historical delivery patterns. This would lower normalized net power costs, because costs would be shifted into the "lower cost" months.

Q. Have you prepared an exhibit showing how you calculated your adjustment?

A. Yes. My confidential Exhibit No. ___ (APB-4C) shows my calculation of the adjustment. I took the Company's modeled monthly energy deliveries in the months of October, November, and December and multiplied that by the difference between the average monthly forward energy prices of April-June 2011 and the average monthly forward energy price of October – December 2011. This calculation estimates the decrease in costs to meet the SMUD contract obligations based on actual historical energy deliveries by moving the energy deliveries from October through December into the "lower cost" months.

This is a very simplified estimate of the effect of modeling the SMUD contract appropriately. To develop a more accurate adjustment, the Company should, if the Commission accepts this adjustment, model the contract within GRID with deliveries more in line with historical deliveries, as part of its compliance filing.

Q. What is the amount of your SMUD Contract Shaping adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment is $2,499,818 for the total West Control Area, or $554,460 for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level.

D. Colstrip Outage

Q. Your next adjustment is labeled " Colstrip Outage" in Exhibit No. __ (APB-2). Please explain the context of this adjustment.

A. PacifiCorp experienced an extended outage at the Company's Colstrip 4 coal plant during 2009. The outage extended from late March through almost all of October of that year. The Company has used its historical outage experience to develop resource outage rates that are applied in the GRID model.

In this case, PacifiCorp is proposing to use the period 2006 through 2009 as its base for computing average outage rates for its Colstrip 4 resource.

Q. What is the impact of PacifiCorp's decision to use 2006 through 2009 as its base for computing average outage rates for Colstrip 4?

A. This results in an average outage rate of [redacted] for purposes of determining normalized net power costs in this proceeding. Due to the typically incrementally low costs of a base load coal resource, a decrease in modeled generation from these resources will result in higher normalized net power costs.

Q. Regardless of its impact on costs, is it appropriate for PacifiCorp to include this extended outage as part of an average outage analysis?

A. No. No matter what the ultimate effect is on power costs, it is not appropriate for general rate case rate making to include the effects of an anomalous extended outage when determining normalized net power costs. Not only does including such an anomalous outage event produce a less than typical forecast of power supply, but it imbeds in rates costs from events which should be reviewed in the context of potential prudence questions and overall power costs at the time the event occurs.

Q. Please explain what you mean by "reviewed in the context of potential prudence questions and overall power costs at the time the event occurs."

A. Extended outages such as PacifiCorp experienced at the Colstrip 4 facility in 2009, is not the norm for these types of resources. The average annual outage rate calculated using such an event would not represent expected outage levels during the rate year.

In determining general rate case base rates, it is appropriate to develop modeled outage rates without such anomalies and, if some anomalous event actually occurs that results in an extended outage, parties should be able to review the causes, actions the Company takes in response, and other factor related to the outage before ratepayers are required to absorb the costs. As part of this review, the parties should be able to review all power related costs to explore other factors that may have mitigated the costs associated with an extended outage.

Q. Can you provide an example of such a review?

A. Yes. Avista is a part owner of Colstrip 4. In the recent Avista general rate case before the Commission, Staff reviewed the extended outage at Colstrip 4 from Avista's perspective. Staff found that Avista's share of the cost of that outage was mitigated by lower gas prices and favorable secondary energy prices during the outage period, as well as favorable water conditions that increased hydro-generation, which replaced some of the energy from Colstrip 4 Avista lost during the outage.

Q. Did Avista use the extended outage at Colstrip 4 in developing net power costs for ratemaking purposes in its recent rata case before the Commission?

A. No. In the settlement agreement that is now before the Commission, Avista agreed to use Colstrip outage rates determined without the anomalous outage rate years.

Q. Does your reference to the need to review the prudence and other circumstances surrounding the extended outage imply that PacifiCorp is entitled to some recovery of costs associated with such events?

A. Perhaps. However, it is up to the Company to file an accounting petition with the Commission requesting deferral and possible recovery of such excess costs. The parties would be able to review the event and the proposed cost recovery at that time.

Q. Is this review process consistent with the treatment of other regulated electric utilities in Washington?

A. Yes, although for Avista and Puget Sound Energy, the Commission typically reviews power cost effects from abnormal or anomalous events as part of each company's annual power cost adjustment filing.

Q. How did you calculate your adjustment?

A. I estimate the benefit from removing the 2009 extended outage by basing the Colstrip 4 outage rate on an 8 percent effective outage rate, or EFOR. The rate is well above the recent historical average for Colstrip 4, as observed in the recent Avista general rate case, less the effects of the 2009 extended outage.

In Avista's recent rate case, Docket UE-100467 et al, Avista's witness Kalich provided a chart of Colstrip forced outage history. The lifetime average was shown to be 11.6 percent for Colstrip Units 3 and 4 combined, with a 5-year rolling average of 9.36 percent, including the extended outage in 2009 and much lower than that without including the 2009 extended outage.

Without running the GRID model, I calculated my adjustment by taking PacifiCorp's share of the additional average monthly energy that would be available from Colstrip 4 using an 8 percent EFOR and multiplying that by the difference between the monthly average market price over the period April 2011 through March 2012, and the incremental cost of Colstrip 4 generation. My confidential Exhibit No. ___ (APB-5C) shows this calculation.

This adjustment amount approximates what the Company would save in net power costs by not having to make market purchases, or what additional revenues it might receive from selling into the market. Incorporating a lower EFOR rate into the GRID model as part of any compliance filing would more accurately evaluate the effect of this recommendation.

Q. What is the amount of your Colstrip Outage adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment is $1,545,939 for the total West Control Area, or $342,889 for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level.

E. DC Intertie

Q. Your next adjustment is labeled " DC Intertie" in Exhibit No. __ (APB-2). Please provide the context for this adjustment.

A. The Company has included significant annual costs associated with a DC Intertie and Network Transmission Agreement between Bonneville Power Administration and PacifiCorp. As stated in the Company's response to ICNU Data Request 10.1, this agreement provides wheeling from the Nevada-Oregon Border ("NOB") to the Buckley substation. PacifiCorp then has wheeling rights from the Buckley substation to its system loads, providing the Company the ability to make purchases at NOB.

Q. What is the issue?

A. The Company has provided no justification for the annual expense. In fact, the Company admits in its Response to ICNU Data Request 10.3 that NOB purchases have relatively high prices, so they are the last option to serve the Company's retail loads. The Company goes on the explain: "Since this capability is unlikely to be used under the normalized circumstances contained in the Company's WCA GRID model, no purchases are modeled at NOB during the test year."

The result is that the Company is attempting to recover significant costs, yet can provide no explanation for the corresponding benefits. Therefore, the Commission should remove the annual amount related to this contract from the determination of net power costs until PacifiCorp identifies, quantifies and includes the corresponding benefits.

Q. How did you calculate your adjustment?

A. I removed the cost associated with the DC-Intertie from the determination of normalized net power costs.

Q. What is the amount of your proposed DC Intertie adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment is $4,766,400 for the total West Control Area, or $1,057,187 million for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level.

F. Idaho PTP

Q. Your next adjustment is labeled "Idaho PTP" in Exhibit No. __ (APB-2). Please provide the context for this adjustment.

A. The Company has included costs associated with a point-to-point wheeling contract with the Idaho Power Company for service between Idaho Power and West Main. X [redacted] "PACE" means PacifiCorp's East Control Area; "PACW" means PacifiCorp's West Control Area. The contract therefore clearly provides benefits to both PACW and PACE.

Q. What is the issue?

A. The Company appears to be proposing that the Commission should allocate the entire cost of the wheeling contract to the West Control Area and thus, in part, to Washington. However, at a minimum, these contract costs should be split between the West Control Area and the East Control Area, because both control areas benefit from the service provided under the contract.

Q. How did you calculate your adjustment?

A. I split the cost associated with the Idaho PTP contract evenly between control areas, and removed the East Control Area portion from the determination of normalized net power costs.

Q. What is the amount of your proposed Idaho PTP adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment is $1,583,040 for the total West Control Area, or $351,118 million for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level.

G. Wind Integration Costs

Q. Your next adjustment is labeled "Wind Integration Costs" in Exhibit No. __ (APB-2). Please provide the context of this adjustment.

A. The Company is including approximately $11.3 million in Company costs for WCA wind integration charges, in addition to just over $3 million the Company paid to BPA for wind integration. This is a significant increase over any previous costs and it is a significant cause of the Company's overall requested increase in this proceeding – approximately $8.7 million on a West Control Area basis.

The Company has not modeled wind integration costs within its GRID model, choosing instead to calculate the amounts based on separate wind integration studies. Based on the initial wind integration study used in this proceeding, the Company claims costs have increased from $1.15 per MWh in the previous general rate case to $6.97 per MWh in this proceeding; a six-fold increase in one year. (Exhibit No. ___ (GND-1T), page 6).

In his testimony, the Company's witness Mr. Duvall goes on to explain the manner in which wind integration charges are separated into two categories –

resources within BPA's control area that rely upon BPA's latest Record of Decision on wind integration charges, and those resources located within the Company's control area. The Company's initial costs for resources located within its control area were based on a 2008 IRP. (Exhibit No.___(GND-1T), page 6).

Mr. Duvall also testifies that the wind integration study would be updated by August 2, 2010, at which point the Company will update its wind integration costs.

Q. What is the issue?

A. The issue is the reliability of the wind integration costs PacifiCorp uses in its direct case. The updated study which the Company expected in early August 2010 was completed only recently, in early September 2010, and the Company has made no related updates to its rate case costs that I am aware of. Furthermore, in response to Staff Data Request 144, which Staff received on September 14, 2010, the Company claims that wind integration costs based updating its wind integration study would now be in the range of $9.01 per MWh. Clearly, the range of costs presented in various studies in a matter of one year, leads one to question the accuracy and validity any proposed wind integration cost.

Staff has had no opportunity to review and analyze the updated study, nor address any proposed changes in the Company's proposed costs for ratemaking purposes.

Based on the complex nature of these studies and what appear to be seemingly endless revisions upward, the use of any proposed cost related to wind integration in this proceeding is questionable, it certainly fails to satisfy the Commission's "known and measurable" standard.

Q. How should the Commission resolve this issue?

A. The Commission would be justified in removing all wind integration costs for resources in the Company's West Control Area until the latest studies are reviewed, critiqued, and accepted by all parties. This would result in a $11.3 million adjustment to normalized net power costs in this proceeding on a West Control Area basis.

Alternatively, the Commission could chose to remove the wind integration charges until the Company files a power cost adjustment mechanism that is acceptable to the Commission – a mechanism that would capture the known and measureable costs of integrating wind resources into its system based on actual generation costs, as compared to a base level of costs.

Finally, the Commission could order the Company to explore the possibility of modeling wind integration costs using its power supply dispatch model, in the hope that a more accurate and perhaps less controversial cost estimate could be determined.

Q. Are you recommending any of these alternatives in this proceeding?

A. No. While removing uncertainties of wind integration costs based on theoretical, simple spreadsheet models, and using actual costs determined through a power cost mechanism has its appeal, I am not recommending that action at this time.

Q. What do you recommend?

A. I recommend several simple adjustments related to removing those wind resource. These adjustments are based on the Company's wind integration costs as filed. The first wind integration adjustment removes the costs associated with the non-SCL owned Stateline project. PacifiCorp provides wheeling services for a partner in the project and receives no benefits in the form of power from the project for Washington ratepayers. Absent revenues for wind integration services related to any wind integration services, ratepayers should not be responsible for the costs. This adjustment is identified in my Exhibit No. ___ (APB-6), line 1.

The second adjustment is to remove the wind integration costs associated with what is identified as the Cambell Wind Farm. This wind farm provides no power for Washington ratepayers, nor does PacifiCorp recover wind integration costs from the owners. The Company appears to have no specific operational information about this project, choosing instead to base information on the "nearby" Stateline project.

In addition to the lack of compensation for wind integration cost recovery from the owners, I remove the costs associated with this project as being not known and measureable. This part of the adjustment is shown on my Exhibit No. ___ (APB-6), line 2.

The next adjustment is based on removing all wind integration costs associated with what is identified as Oregon Qualifying Facilities. The costs and benefits of Qualifying Facilities are assigned on a situs basis under the WCA allocation methodology. The Washington net power cost analysis submitted by the Company does not include generation from Oregon Qualifying Facilities. Therefore, the wind integration costs of the Oregon Qualifying Facilities should be removed for purposes of Washington Ratemaking. This adjustment amount is shown on Exhibit No. ___ (APB-6), line 3.

Finally, I remove the wind integration costs associated with SCL's Stateline wind farm. The principal reason for this adjustment is the combined concerns that the present exchange contract with SCL terminates at the end of the rate year and with the overall uncertainty in the actual costs of integrating wind I discussed earlier; the Company has not justified including these costs in rates at this time. The adjustment amount is shown on Exhibit No. ___ (APB-6), line 4.

Q. What is the total amount of your proposed Wind Integration Costs adjustment to the Company's proposed pro forma normalized net power costs?

A. As summarized in Exhibit No. __ (APB-6), lines 6 and 7, my proposed adjustment totals $5,504,153 million for the total West Control Area, or $1,220,881 million for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level. These adjustments are conservative, given the overall uncertainties of the wind integration costs.

H. Gas Price Update

Q. Your last adjustment is labeled "Gas Price Update" in Exhibit No. __ (APB-2). Please explain the context of this adjustment.

A. The Commission has recently been allowing regulated electric utilities to update certain costs during the general rate case process, as long as there is a suitable transparency to the calculation and adequate time for the other parties to review the updated amounts. Typically, those updates have been limited to gas prices, new firm contracts, or budget updates from third party owners of resources such as the Mid-Columbia project owners. This transparency is critical, given the usual timing involved when they occur.

During the course of this proceeding, the Company did not provide any new normalized net power cost studies based on the latest gas prices and firm contracts, until it responded to Staff Data Request 143. Staff submitted Data Request 143 on August 30, 2010, and the Company responded on September 8, 2010. Interestingly, the forward price curves used by the Company in its September 8th "update" are dated from June 30, 2010. In addition, to "updating" gas prices, the Company made several other non-gas price or new firm contract changes. The amounts and description of each updated item included in the Company's response to WUTC Data Request 143 and ICNU Data Request 16.12 and are summarized in my Exhibit No. ___ (APB-7).

Q. Do you accept the Company's "update" as an appropriate adjustment to the Company's normalized net power costs as filed?

A. No. The Company's update contains items that are inappropriate for inclusion in Washington rates. In addition, the June 30th date for the gas forward price curves is not current and should be updated using more contemporaneous data. However, for purposes of estimating adjustments in my testimony I did use the June 30th forward prices as provided by the Company.

Q. What adjustment do you recommend?

A. I recommend the Commission outright reject two of the items that the Company included in its response to WUTC Data Request 143. This recommendation assumes that the Company, will in its rebuttal filing, propose adjustments related to these items.

The first item is an adjustment related to the ability of the Chehalis plant to carry reserves on the Company's system. The Company is claiming that BPA's recent "refusal" of PacifiCorp's request for Dynamic Scheduling takes away the Chehalis plant's ability to provide reserves, thus increasing normalized net power costs. The Commission should reject this cost increase. The Company has provided no specific explanation of the rejection, nor has it addressed the possibility of renewed negotiations with BPA on the matter.

However, the increase in costs can be rejected based on the Company's own testimony in Docket UE-090205, the Chehalis plant prudence review, in which Company witness Mr. Duvall, when asked:" Is the Plant used and useful for

Washington?," testified that: "the Plant will ultimately replace four long-term purchase power agreements in the West Control Area that will expire between the summer of 2011 and 2012. These four contracts currently provide 789 MW of capacity to the West Control Area and flexibility to provide operating reserves as well as follow changes in loads and wind generation. "(emphasis added) (Exhibit No. ___ (GND-1T), page 6 in Docket UE-090205).

Ratepayers should not now be on the hook, if prudence-based claims by the Company do not materialize. Clearly, any costs associated with the Chehalis plant not being able to carry out the claims of the Company should be rejected.

The second updated item is an increase in costs associated with the tariff rate of Idaho PTP wheeling service. The Commission should reject this Company attempt to recover the entire amount of the increase from the West Control Area. The effects of any such rate increase should be split in the same manner as I discussed early under Section F – Idaho PTP.

Finally, the Commission should require the Company to submit a more contemporaneous gas price update. I recommend the Commission order the Company to file a normalized net power cost update to include ONLY updated gas prices and any new long-term firm contracts that have been entered into. The update should reflect futures prices as contemporaneous as possible. In addition, the futures price should be from generally publically available data that can be timely reviewed and considered by the parties.

I recommend the Company adopt the methodology used by Avista and accepted by this Commission – the latest available 3-month average of future monthly forward prices.

Q. How did you calculate your proposed adjustment for just the Chehalis plant and Idaho PTP increase issues?

A. I simply removed the amounts associated with the Chehalis reserve update and one-half of the Idaho point-to-point wheeling rate update as included in the Company's response to WUTC Data Request 143. This has the effect of increasing the overall adjustment related to the Gas Price Update by an additional $2,372,757 on a WCA basis, as shown in my Exhibit No. ___ (APB-7).

Q. What is the amount of your proposed Gas Price Update adjustment to the Company's proposed pro forma normalized net power costs?

A. My proposed adjustment, including the items above, is $3,457,535 for the total West Control Area, or $766,881 for Washington, based on an average of the CAEW and CAGW allocators. These figures are at the expense level. However, this amount should be further adjusted using the more contemporaneous gas price update I discussed above.

Q. What is your approximate total proposed adjustment to the Company's pro forma normalized net power costs?

A. As shown in my Exhibit No. ___ (APB-2), the total Washington expense level adjustment is $5,292,148, to be adjusted using actual GRID model runs where appropriate.

Q. **Does this conclude your testimony?**

A. Yes.