Exhibit No.___(GND-5T)
Docket No. UE-100749
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
	)	Docket No. UE-100749
Complainant,	)	
vs.	)	
PACIFICORP dba Pacific Power	)	
Respondent.	)	

PACIFICORP

REBUTTAL TESTIMONY OF GREGORY N. DUVALL

November 2010

Q. Are you the same Gregory N. Duvall that previously provided testimony in this docket?

A. Yes.

Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses three subjects: revenues from sales of renewable energy credits (RECs), load forecasting, and net power costs (NPC).

On the issue of REC revenues, I respond to the adjustments presented by Mr. Michael Foisy on behalf of Staff of the Washington Utilities and Transportation Commission (Staff) and by Mr. Randall Falkenberg on behalf of the Industrial Customers of Northwest Utilities (ICNU).

Regarding load forecasting, I respond to the temperature normalization adjustment proposed by Ms. Vanda Novak on behalf of Staff and the retail revenue adjustment proposed by Mr. Greg Meyer on behalf of ICNU and Public Counsel.

With respect to NPC, I sponsor the Company's new proposed level of NPC, reflecting corrections and updates designed to improve the accuracy of the NPC forecast. I also respond to the adjustments presented by Mr. Alan Buckley on behalf of Staff and by Mr. Falkenberg on behalf of ICNU.

Q. What does your testimony demonstrate?

A. First, I explain how the $5.0 million revenue requirement credit for REC revenues included in the Company's rebuttal addresses Staff's and ICNU's proposals for a revenue credit in base rates. I demonstrate the inappropriateness of other aspects of Staff's REC adjustment, especially Staff's proposal for a retroactive, incremental regulatory liability account to track REC revenues.

Second, I explain why the Company's temperature normalization of commercial class loads is reasonable and why the Company's residential revenues are more accurate than those proposed by ICNU and Public Counsel.

Third, I explain the reasonableness of the Company's approach to updating its NPC. I review each of the adjustments proposed to NPC in detail, explaining the Company's position on the adjustments and providing evidence in support of these positions.

Renewable Energy Credit Revenue (ICNU Adjustment 23 and Staff Adjustment)

Q. Please explain how the Company treated REC revenues in its filing.

A. The Company's NPC are based upon forecasted NPC for the twelve-months ending March 31, 2012, tied to the rate effective period. As explained in the direct testimony of Mr. R. Bryce Dalley, the Company projected several generation-related items through this same time period to match NPC, including REC revenues. Based on the Company's plan to not sell any Washington-allocated eligible RECs during the twelve-months ending March 31, 2012 for compliance with Washington's Renewable Portfolio Standard (RPS), WAC 480-109-020, the Company did not reflect any revenues associated with REC sales in the case.

Q. Please explain the REC revenue adjustment proposed by Staff.

A. Staff contends that the Company has more RECs than necessary for RPS compliance in the rate effective period so it is unreasonable for the Company not to reflect any REC revenues in this case. Staff proposes an adjustment of $4.2 million, reflecting REC sales in the 2009 calendar year historic period. On top of this adjustment (and not as a true-up to it), Staff also proposes that the Commission record in a regulatory liability account all REC revenues from January 1, 2010 forward.

Q. Please explain ICNU's REC revenue adjustment.

A. ICNU also rejects the Company's proposal to not sell any Washington-allocated RECs as unreasonable. ICNU proposes a revenue adjustment of $4.87 million based upon its projections of Company REC sales for 2012.

Q. Why did the Company plan to not sell any Washington RECs, even those in excess of the minimum required for RPS compliance?

A. The Company's plan anticipated legislative changes to Washington's RPS which would allow longer-term REC banking. At the time of the filing, the Company was hopeful that such changes would be enacted prior to 2011.

Q. Is the Company willing to change its plan to not sell any Washington-allocated RECs in excess of minimum RPS requirements for the rate effective period?

A. Yes, because it is now clear that the RPS will not be amended to change REC banking provisions prior to the rate effective period in this case.

Q. If the Commission orders the Company to sell Washington-allocated RECs in the rate effective period, does the Company agree that rates should reflect a revenue credit for these sales?

A. Yes. The Company does not object to a revenue credit in base rates reflecting

REC sales, as long as normal ratemaking rules and principles are employed in calculating this credit. Indeed, the Company's current revenue requirement reflects such a revenue credit to account for REC sales prior to the effective date of the RPS.

Q. Please explain the revenue credit for REC sales currently reflected in rates.

A. As noted in Order 09 in Docket UE-090205, the stipulated revenue requirement approved by the Commission included in base rates an adjustment for projected REC sales in the rate period.

Q. Did the Stipulation approved in Docket UE-090205 contain other provisions relevant to the issue of REC revenues?

A. Yes. The approved Stipulation required the Company to provide periodic REC reports to the parties to promote "transparency in the Company's management of these credits." Order 09 at 22. In support of this provision, ICNU noted that REC reporting provides "the Parties the practical ability to file for deferred accounting or request that the Commission take another action regarding PacifiCorp's Washington-allocated RECs." Order 09 at 15. The Company has been providing these REC reports since December, 2009.

Q. Please provide more detail on the two different parts of Staff's proposed REC revenue adjustment.

A. First, Staff's adjustment proposes to include in the test year revenues of $4,211,639 associated with REC sales in the 2009 base period. Second, Staff proposes the tracking of all REC sales from January 1, 2010 forward through a regulatory liability account.

Q. Is the first aspect of Staff's adjustment similar to ICNU's adjustment?

A. Yes. Both recommend reflecting a revenue credit in base rates for REC sales.

Q. Does the Company agree with this general approach?

A. Yes. Mr. Dalley's rebuttal testimony reduces revenue requirement by $5.0 million to reflect the use of REC revenues in the historic period as a basis for setting prospective REC revenue levels in rates. While the Company does not agree to the method by which Staff or ICNU calculated their adjustments, the Company's proposed reduction in revenue requirement for REC revenues is greater in magnitude and effectively addresses Staff's and ICNU's base rate adjustments.

Q. What are the Company's concerns about other aspects of Staff's adjustment?

A. Staff's adjustment treats the REC revenues in the historic base period as amounts that should be refunded to customers, on top of any revenues generated in the future (and also in the period between January 1, 2010 and the rate effective date in this case). An adjustment to refund REC revenues from the historic base period constitutes retroactive ratemaking, which is illegal under Washington law. While it is appropriate to set prospective rates using REC revenue levels derived from the historic base period, the Commission cannot "retain" the REC revenues from this period as proposed by Staff witness Mr. Foisy. Retroactive ratemaking similarly prevents the Company from seeking to recover additional costs even though it under-recovered its NPC in this period and did not earn its allowed rate of return.

Q. Does the Company object to the second aspect of Staff's adjustment, proposing to create a regulatory liability account to track REC revenues from January 1, 2010 forward?

A. Yes, for several reasons. First, Staff's proposal to reflect a REC revenue credit in base rates and track the revenues through a regulatory liability account would result in a double-counting of these revenues. This is true for current rates (which reflect the REC revenue credit approved in Docket UE-090205) and for prospective rates, assuming the Commission approves the proposal to reflect $5.0 million of REC revenues in rates.

Q. What is the second reason why you object to Staff's proposal for a regulatory liability account?

A. Staff proposes to track REC revenues through a regulatory liability account, but does not propose to match and track NPC in this way, even though the RECs and megawatt hours are generated from the same source at the same time. It violates the matching principle to track revenues on a dollar-for-dollar basis, but not track related costs in this same manner.

In addition, the Commission previously rejected the Company's request for a power cost adjustment mechanism on the basis that the Company's allocation methodology produced "pseudo" actual power costs, not the actual power costs necessary for such a mechanism. Unless reconsidered, this precedent appears to preclude tracking of actual REC revenues because the same "pseudo" actual issue is implicated. Under the WCA, Washington should receive a higher allocation percentage of RECs from RPS eligible resources in the west control area however there cannot be any double counting of RECs that are already allocated to other states under the Revised Protocol. Confidential Exhibit No.___(GND-6C) shows the "pseudo" RECs allocated to Washington under the WCA. The Company cannot make actual sales of these "pseudo" RECs and instead needs to provide Washington's revenue credit through a "pseudo" actual approach.

Q. What is the third reason you object to Staff's proposal for a regulatory liability account?

A. Staff proposes to begin recording revenues in the regulatory liability account on January 1, 2010—ten months prior to the filing of Staff's testimony and fourteen months prior to the rate effective date in this case. No party to this case has filed a request for deferred accounting related to REC revenues, even though the parties expressly reserved their right to do so in the Stipulation approved in the Company's previous rate case filing. It is retroactive ratemaking to defer amounts prior to the filing of a petition for a regulatory accounting order. At this point, no such petition has been filed, even though the parties expressly reserved their right to make such a filing in the Stipulation approved in Docket UE-090205.

Q. Under what conditions would the Company accept a regulatory liability account for REC revenues?

A. To address the concerns just outlined, the regulatory liability account would need to: (1) be in lieu of a base rate adjustment or be trued up to a base rate adjustment; (2) fairly account for deviations between NPC in rates and actual NPC; and (3) track REC revenues prospectively from the rate effective date in this case.

Q. Mr. Foisy cites the Commission's recent order in Puget Sound Energy Docket UE-070725 as support for his adjustments. Please comment.

A. Based upon my understanding, the Puget Sound Energy (PSE) order stands for the proposition that customers are generally entitled to a revenue credit for REC sales. The Company does not contest this premise, as illustrated by the REC revenue adjustment already in its rates. There is nothing in the PSE order, however, that supports the proposition that normal ratemaking principles should be disregarded when calculating a REC revenue adjustment. The PSE order did not result in a regulatory accounting order that operates incrementally to an adjustment to base rates, nor did parties in that case make any argument to track REC revenues that pre-dated PSE's filing for a regulatory accounting order.

Retail Load Adjustments

Temperature Normalization (Staff Adjustment)

Q. Please summarize Staff's position on the Company's commercial temperature normalization methodology.

A. Staff witness Ms. Novak recommends the Commission remove the effect of the Company's temperature normalization adjustment as it relates to the commercial class. This is shown in Staff Adjustment 3.7. Ms. Novak's recommendation is based on her view that the statistical "fit" of the sensitivity function developed for the commercial class data has not been adequately supported by the Company.

Q. Does Ms. Novak agree that the commercial class usage is weather sensitive?

A. Yes, Ms. Novak, on page 9 line 14 of her testimony agrees that the commercial class is weather sensitive based on the load research data and the Company's commercial survey. In addition, she agrees that the overall temperature normalization methodology used by the Company is consistent with the Commission approved Stipulation in Docket UE-050684.

Q. How does Ms. Novak measure the statistical "fit"?

A. Ms. Novak relied on the R-squared statistic to measure the statistical "fit" as described in her testimony. Ms. Novak claims that an R-squared of 0.644 is not a good enough fit.

Q. Do you agree that it is appropriate to rely solely on an R-squared analysis to evaluate the Company's approach to commercial class temperature normalization?

A. No. First, while a statistical analysis of a model, such as an R-squared analysis, can provide important information, it is not appropriate to use it as the single measure of the model. Proper model selection should be based on several criteria and focusing on R–squared alone can give an incomplete picture. Second, the value of R-squared can be misleading because it will increase when more independent variables are added to the regression, even though those variables may not add any additional explanation to the model. This is true regardless if the R-squared is 80 percent or 64 percent. Moreover, by adding more variables, one can end up with wrong signs and/or biased estimates.

Q. How should the Commission evaluate the Company's commercial class temperature normalization adjustment?

A. Model selection requires judgment in addition to a review of the model statistics. Best practices adopted by the electric utility industry for the purposes of weather normalization of commercial class loads would advocate retaining weather variables in the model as long as they have the correct sign and there is reasonable evidence of significant penetration of space cooling and heating equipment in the service territory. This is based on the econometrics principle that all relevant explanatory variables should be included in a full multiple regression equation, if they are believed to be theoretically relevant in explaining variations in the dependent variable. (R. J. Wonnacott and T. H. Wonnacott, “Econometrics": page 410). In other words, the Company’s adjustment for weather normalization should be included in the commercial class sales forecast, absent evidence that it is producing erroneous results or was calculated in a manner inconsistent with Commission practice.

Q. Does the statistical evidence support retention of the Company’s commercial class temperature normalization adjustment?

A. Yes, for two reasons. First, an R-squared value of 0.644 means that nearly two-thirds of the variation in load is explained by variations in temperature. Given the non-homogeneous nature of the commercial class in Washington, this is reasonable.

Second, the statistical “fit,” as measured by the R-squared statistic, degrades when the Company’s temperature normalization adjustment is removed from the model. Specifically the R-squared value declines by six percentage points, from 0.64 to 0.58. This demonstrates that Staff’s proposal to remove the temperature normalization adjustment decreases the accuracy of the commercial class load forecast.

Q. Ms. Novak recommends that PacifiCorp improve the temperature normalization adjustment for the commercial class in future cases. How do you respond to this recommendation?

A. The Company is willing to commit to working with Staff and other interested parties on this issue prior to filing its next general rate case in Washington.

Q. What is your recommendation to this Commission?

A. Based on the above, the Commission should reject Staff's removal of the commercial temperature normalization adjustment in this case.

Retail Revenue (ICNU/Public Counsel Adjustment)

Q. Please summarize ICNU's and Public Counsel's position on the Company's proposed level of residential revenues.

A. ICNU and Public Counsel witness Mr. Meyer recommends that the level of residential revenues be increased, resulting in a $2.2 million reduction to revenue requirement. He claims that the Company's 2009 temperature normalized usage per bill of 15,128 kWh is too low when compared to the average actual residential use per bill of 15,671 kWh as measured over the five-year period 2005 through 2009. To compute the higher residential use per bill, Mr. Meyer makes three changes to the Company's filing. First, he removes the temperature normalization adjustment from the historic data. Second, he extends the period for measuring use per bill from one year (2009) to five years (2005-2009). Finally, he reverses the out-of-period adjustments made by the Company as shown in Mr. Dalley's Exhibit No.___(RBD-3), table 2.

Q. Have you quantified the impact of these three changes?

A. Yes. Table 1 identifies the cumulative effect of the three changes proposed by Mr. Meyer.

Table 1

Increase from Company (millions)	**Use per Bill (kWh)**	**Description**
NA	15,128	Company proposal
$0.22	15,182	Remove out of period adjustments
$0.64	15,286	Use 5-year average instead of 2009 test period
$2.24	15,671	Remove temperature normalization

Q. What does Table 1 show?

A. Table 1 shows the largest of Mr. Meyer's three adjustments is the removal of the temperature normalization which constitutes $1.60 million or 71 percent of his proposed $2.24 million adjustment.

Q. Did Mr. Meyer change NPC, allocation factors, or the production factor to reflect his proposal to increase Washington residential sales levels?

A. No. While he attempted to account for the NPC effect, he used an average embedded NPC rather than computing incremental costs.

Q. Is it reasonable to remove the Company's temperature normalization of residential loads?

A. No. Mr. Meyer's proposal implicitly assumes that residential loads in Washington are not affected by temperature. This is inconsistent with the Stipulation on temperature normalization methodology the Commission approved in Docket UE-050684, which specifically contemplates the temperature normalization of residential loads. Mr. Meyer provides no rationale as to why it is appropriate to ignore temperature normalization for the residential class; indeed, his testimony does not even acknowledge that the bulk of his adjustment comes from the removal of the Company's temperature normalization adjustment.

Q. Would Mr. Meyer's adjustment reduce the accuracy of the residential load forecast?

A. Yes. Removing the Company's temperature normalization of residential loads would decrease the accuracy of the forecast. Ms. Novak's testimony for Staff reinforces this point, noting that the Company's residential class forecast demonstrates a good "approximation of the relationship which exists between temperature fluctuations from customer comfort base points and electricity consumption."

Q. How do you respond to the other aspects of Mr. Meyer's proposal?

A. Mr. Meyer presents no evidence, rationale or precedent for using a five-year average or for excluding out-of-period adjustments. Both proposals are inconsistent with the Commission approved method of using the test-period normalized sales for purposes of developing present revenues in the case. The Commission has traditionally normalized sales for temperature over a long-term time horizon. In contrast, Mr. Meyer's proposal uses a simple average of actual sales over a much shorter time period of five years.

Recommendation for Company's Net Power Costs

Q. In your direct testimony, you recommended that the Commission set the Company's west control area NPC at $569.9 million for the twelve-month period ending March 31, 2012. Has your NPC recommendation changed?

A. Yes. The Company has decreased its recommended west control area NPC to approximately $557.6 million.

Q. Why have you decreased your west control area NPC recommendation to $557.6 million?

A. This decrease is predominantly due to updating NPC to reflect new information, including the most recent forward price curve. The decrease also reflects corrections and the Company's acceptance of certain adjustments proposed by Staff and ICNU.

Q. Please summarize the change in NPC from your direct testimony on a west control area and Washington-allocated basis.

A. Exhibit No.___(GND-7) summarizes the cost impact of the updates, corrections, and adopted adjustments that result in a change to west control area NPC of approximately $12.4 million and Washington-allocated NPC of $2.7 million.

NPC Updates and Corrections

Q. Please explain the corrections the Company has made to the calculation of NPC.

A. The Company corrected three elements of NPC that it identified in its Responses to WUTC Staff Data Request 143 and ICNU Data Request 16.12, attached as the top section in Exhibit No.___(GND-7). First, the Company corrected the ownership share applicable to the Jim Bridger Plant. Second, the Company corrected the energy charge applicable to the Grant contract. Third, the Company corrected Tieton non-owned reserve contributor. The impact of the corrections on west control area NPC is a decrease of approximately $343,812, as reflected in Exhibit No.___(GND-7).

Q. Has the Company updated its NPC calculation with more timely information?

A. Yes. In its Responses to WUTC Staff Data Request 143 and ICNU Data Request 16.12, the Company updated NPC with a more recent official forward price curve (from June 2010). The Company's update also reflected prices for indexed contracts, transmission and transportation costs, and mark to market value of physical natural gas transactions and financial swaps. Exhibit No.___(GND-7) provides a summary of the impact on the west control area NPC for each of the items.

Q. What is the impact of these updates?

A. These updates reduce west control area NPC by approximately $3.1 million.

Q. What forward price curve did the Company use to update NPC in its rebuttal filing?

A. The NPC described in my rebuttal testimony have been updated to reflect the most recent official forward price curve, dated September 30, 2010, that reduces west control area NPC by approximately $12.8 million. The Company produces official forward price curves on a quarterly basis. Therefore, the September 30, 2010 curve was the latest available at the time of this filing. Prices in the

September forward price curve declined from the previous prices and resulted in a reduction to coal generation in the GRID model. This, in turn, caused the unit coal cost to increase since fixed mine costs needed to be apportioned over fewer tons of coal, in addition to updates to third party coal contracts. No changes were made to the level of captive mine costs. The impact of updating for coal costs increases west control area NPC by approximately $1.1 million.

Q. Does the Company propose to update NPC with a forward price curve that is closer in time to the rate effective period?

A. Yes. The Company proposes that it make a compliance filing prior to rates going into effect on April 1, 2011 to update NPC using the December 31, 2010 forward price curve.

Q. Do the Company's proposals to use its most recent forward price curves for NPC updates respond to Staff's concerns on this issue?

A. Yes. Staff proposed that the Company update NPC using a more contemporaneous gas price update than the one supplied in response to WUTC 143. Staff also indicated that the forward prices on which the update is reviewed should be based upon generally publically available data that can be timely reviewed and considered by parties. PacifiCorp's official forward price curve satisfies these conditions. While PacifiCorp is unfamiliar with the details of the Avista methodology referenced by Staff ("the latest 3-month average of future forward prices"), PacifiCorp does update its official forward price curve every three months, using then current future forward prices. Therefore, PacifiCorp's proposed forward price curve update appears to be generally consistent with Staff's proposal.

Q. What are Staff's and ICNU's positions on the Company's proposed updates?

A. Both Staff and ICNU support updating NPC to reflect the most recent forward price curve. However, they oppose updating NPC for decreased reserve carrying capacity associated with the Chehalis plant and propose removing half of the Idaho Power point-to-point wheeling update. Staff argues that the updates should be limited to "gas prices, new firm contracts, or budget updates from third party owners of resources."

Q. Why are the updates related to the Chehalis plant operating reserves and Idaho Power point-to-point wheeling costs reasonable?

A. The Company's update serves the Commission's interest in having a full and accurate record. All parties agree that the Company's filing should be updated with a more recent forward price curve. It would violate the matching principle to update the price curve but ignore other verifiable, transparent changes to NPC, such as operating reserves and contract updates.

Q. Did parties have a reasonable amount of time to audit the Company's proposed updates before filing their responsive testimony?

A. Yes. Staff requested data updating NPC in WUTC Data Request 143 and the Company responded on September 8, 2010. The Company provided additional data on the updates in response to ICNU 16.12, served on September 23, 2010.

Q. What was the basis for the update to the Chehalis reserves?

A. On April 30, 2010, just days before the initial filing in this proceeding, the

Bonneville Power Administration (BPA) rejected the Company's request for dynamic transfer capability, which in turn restricts the Company's ability to use the Chehalis plant to provide operating reserves. As a result of this event, the Company updated NPC in WUTC Data Request 143 to restrict the ability of Chehalis from providing any operating reserves. Correspondence with BPA verifying their decision is provided as Confidential Exhibit No.___(GND-8C). To provide dynamic scheduling, BPA's Dynamic Scheduling business practices would require the Company have Automatic Generation Control (AGC) on Chehalis, which is not currently installed.

Q. How do you respond to Staff's and ICNU's proposal to reject this adjustment?

A. This change is transparent, can easily be verified based on the information provided in Confidential Exhibit No.___(GND-8C), and is straightforward to model in GRID. It is no more complex to verify than gas prices, new firm contracts, or updates from third party owners of resources. All one needs to know is that BPA's Dynamic Scheduling business practices require AGC to be installed on Chehalis as a condition precedent to BPA entering into a contract providing dynamic scheduling. Since the Chehalis plant is in BPA's balancing area, dynamic scheduling is required in order for the Company to carry reserves on the Chehalis plant. The Chehalis plant does not currently have AGC.

Q. Mr. Buckley claims that ratepayers should not be on the hook if the Company's claims of prudence do not materialize. Mr. Falkenberg claims that prudence is now an issue, which could be time consuming. How do you respond to these claims?

A. I disagree that this change in reserve assumptions raises prudence issues, or that for ratemaking purposes the Company or customers are locked into the assumptions that were made at the time the prudence of the Chehalis plant was reviewed by the Commission. Such an approach would not reflect cost of service ratemaking. Assumptions made at the time a resource is first reviewed by the Commission for prudence are based on the best information known to the Company at the time the decision to acquire the resource was made and will certainly change over time. In hindsight, some outcomes make the acquisition more attractive and others make it less attractive, but regardless, hindsight should not be used to determine prudence.

Q. Mr. Falkenberg suggests that there may be other solutions available to obtaining dynamic scheduling from BPA and their denial may not be the "last word". How do you respond?

A. It is clear from Confidential Exhibit No.___(GND-8C) that this is the "last word" from BPA for purposes of the proper assumption to make about the ability of the Chehalis plant to carry reserves during the rate-effective period. The exhibit also illustrates that the Company suggested an alternative approach to AGC which was rejected by BPA.

Q. Mr. Falkenberg claims that additional discovery is required to determine if the resource is capable of providing ready reserves. Can the Chehalis plant provide ready reserves?

A. No. BPA requires the Company to block schedule Chehalis prior to the hour. If the Company deviates from that schedule, it is required to purchase reserves from BPA to make up the difference.

Q. Finally, Mr. Falkenberg questions the modeling of this change. Please explain the Company's modeling of the adjustment.

A. Thermal plants are modeled in GRID as either having the capability of providing operating reserves or not, and if so, how much. This change is not only simple to model, but it is transparent and objectively verifiable. If the Commission allows updates to the forward price curve, contracts and updates for existing contracts, such as updated pro formas from the owners of the Mid-Columbia plants, then it should allow this update. There is no valid reason to discriminate.

Q. Please explain Staff's and ICNU's adjustment to the update to the Idaho point-to-point wheeling rate reflected in the Company's Response to WUTC Data Request 143 and ICNU 16.12.

A. Staff and ICNU argue that the Commission should disallow half of the increase to the cost of a point-to-point wheeling contract with Idaho Power Company on the basis that the 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. This proposed adjustment is consistent with their proposed treatment of the costs associated with the Idaho point-to-point wheeling rate contained in the Company's direct filing.

Q. Is this a reasonable basis for the proposed adjustment?

A. No. As I discuss more fully below in the section relating to the West Control Area (WCA) Allocation Methodology Adjustments, the Commission has ordered that resources be allocated according to the WCA allocation methodology. The underlying Idaho Power wheeling contract is already split under the WCA allocation methodology between the west control area and the east control area. ICNU and Staff propose to split the portion allocated to the west control area a second time. The portion allocated to the west control area has always been a part of the west control area under the WCA allocation methodology. The proposed adjustment unjustifiably changes the assignment of the contract, which is part of the basic architecture of the WCA allocation methodology.

Company Responses to Specific Adjustments – Overview

Q. How have you organized your responses to the parties' modeling adjustments to NPC?

A. I have grouped the parties' proposed NPC modeling adjustments into three categories. First, there are adjustments to which the Company has agreed in whole. Second, there are adjustments to which the Company has agreed in part or in response to which the Company has proposed a compromise position. Third, there are proposed modeling adjustments that the Company disputes as inaccurate, unsubstantiated, or inconsistent with normalized ratemaking.

Adjustments Accepted in Whole

Q. Does the Company accept any adjustments proposed by Staff or ICNU?

A. Yes. The Company accepts the following proposed adjustments:

- Commitment Logic Screens (ICNU Adjustment 2): As proposed by ICNU, the Company agrees to modify its daily screens consistent with the methodology set forth in the parties' stipulation in Oregon Docket UE 216. This change results in a decrease to west control area NPC of approximately $1.5 million. As discussed later in my testimony, the Company does not agree that this adjustment changes incremental fixed O&M expenses included in the test year, as these expenses were not included in the test year in the first instance.
- Sacramento Municipal Utility District (SMUD) (ICNU Adjustment 6): The Company agrees to adjust the amount of energy sold under the SMUD contract in the test period of the twelve-months ending March 2012 to the level of annual sales allowed under the contract in a calendar year. This reduces west control area NPC by approximately $86,175.
- Inter-hour Wind Integration Costs of Non-Owned Resources (ICNU Adjustment 12; Staff Wind Integration Adjustments): The Company agrees to remove inter-hour wind integration costs associated with the Campbell wind project, Oregon QFs, and the portion of the Seattle City Light (SCL) Stateline wind project that is not delivered to the Company, as proposed by Staff and ICNU. This results in a decrease to west control area NPC of approximately $1.0 million.

Both ICNU's calculations of Adjustment 12 and Adjustment 5 related to the SCL Stateline contract termination remove inter-hour wind integration costs associated with SCL Stateline. Although the Company objects to Adjustment 5 related to the SCL Stateline contract termination in its entirety, should the Commission accept that adjustment, the Company requests that the Commission modify ICNU's adjustment to ensure that the SCL Stateline inter-hour wind integration costs are not removed from NPC twice.

Staff and ICNU also propose adjustments to intra-hour wind integration costs that the Company opposes, as I discuss in the section related to contested adjustments.

- Balancing (ICNU Adjustment 21): ICNU included a placeholder for the balancing effect of implementing ICNU's adjustments. I agree that the Company should make a balancing adjustment to reflect the final adjustments, corrections, and updates ordered by the Commission. The amount of the adjustment is not known at this time.

Adjustments Accepted in Part

SCL Stateline Termination Adjustment (Staff's Adjustment, ICNU Adjustment 5)

Q. Please explain the issue raised by Staff and ICNU with respect to the SCL Stateline wind farm contract.

A. As discussed in Mr. Buckley's testimony, under the energy exchange portion of this contract, the Company receives energy from the Stateline wind farm, owned in part by SCL, and returns the energy to SCL within two months. The provision relating to the Company's receipt of energy terminates on December 31, 2011, and the provision relating to the Company's return of energy terminates on February 29, 2012. Staff and ICNU raise issues related to the fact that this contract terminates within the test year and the fact that the Company's receipt and delivery of energy under this contract terminate at different times.

Q. How does Staff propose addressing these issues?

A. Staff proposes an adjustment that reduces NPC to reflect the value of the energy imbalance in the test period. Staff makes the entire adjustment in January and February of 2012 and does not match the actual delivery and return months.

Q. Does the Company agree with Staff's proposal?

A. While the Company agrees with the concept of matching energy deliveries and returns to calculate the impact of the contract on NPC, the Company proposes a modification to Staff's adjustment. Because the structure of the contract results in what amounts to a two-month lag in recognizing energy returns (*i.e.* energy delivered to PacifiCorp in April 2011 will be returned in June of 2011), I propose removing the April 2011 and May 2011 returns of energy, which represent returns from February 2011 and March 2011, respectively, months which pre-date the NPC test period in this case. This would match up the nine months of energy delivered to the Company from April 2011 to December 2011 with the nine months in which that energy is returned to SCL in June 2011 to February 2012.

Q. Why is this approach an improvement over Staff's approach?

A. The Company's approach more accurately reflects actual deliveries and returns of energy under this contract because it will match the delivery months with the appropriate return months. The Company's approach completely eliminates the difference between energy deliveries and returns under the contract. While Staff's approach is reasonable, it is less accurate than the Company's proposal and would result in a net difference between energy deliveries and returns.

Q. What is the impact on NPC of the Company's adjustment to the SCL Stateline contract?

A. This methodology would result in approximately a $1.6 million decrease to west control area NPC.

Q. Does Staff propose another adjustment based on the SCL Stateline contract?

A. Yes. Staff also proposes to remove the entire wind integration costs associated with the SCL Stateline wind project on the basis that the exchange contract with SCL terminates at the end of the year and that there is uncertainty in actual costs of integrating wind. I address this element of Staff's proposal below in the discussion of wind integration adjustments.

Q. What is ICNU's proposal with respect to the SCL Stateline contract?

A. ICNU recommends that the contract be removed from the test year. While ICNU implies that the contract is imprudent, it appears that the basis for ICNU's proposal is the mismatch between deliveries and returns of energy in the test year. The proposal I discussed above appropriately addresses this mismatch. There is no basis in policy or Commission precedent for removing a contract entirely simply because it expires during the test year. If this were the case, the Company would need to remove other contracts that expire during the test period as identified in my direct testimony, such as the generation from its share of the

Rocky Reach hydro-electric project that is priced at the costs of the project, and the contract with the Grant Public Utility District for displacement energy that is priced BPA's Priority Firm Power (PF) rate. This would likely result in a significant increase to NPC. The existence of the SCL Stateline contract is known and its impact on NPC is measurable, so there is no basis to remove it from rates entirely.

PACE Transmission Cost (ICNU Adjustment 8)

Q. Do you agree with ICNU's proposed adjustment to transmission costs that ICNU claims should be allocated to PacifiCorp's eastern system (PACE)?

A. No, as I discuss in detail below, ICNU's proposal is inconsistent with the Commission-approved WCA allocation methodology. Moreover, it is a proposal to split costs that have already been split once before. However, the Company agrees that the costs relating to providing transmission service to isolated loads in Idaho should be removed. This adjustment reduces west control area NPC by $58,116.

Non-firm Transmission (ICNU Adjustment 10)

Q. Please explain ICNU's position on the modeling of non-firm transmission.

A. ICNU recommends that the Company include non-firm transmission in GRID. ICNU modeled non-firm transmission using a four-year historical average to adjust the capacity of links in the GRID model topology and using a dollar per megawatt-hour energy charge to calculate expenses.

Q. What is the Company's response to ICNU's proposal?

A. The Company agrees to model non-firm transmission in GRID. However, if non-firm transmission is included in the model, it should be included on the same basis as short-term firm transmission. There is no basis for using a different method for non-firm transmission than for short-term transmission. Both types of transmission should be modeled using a four-year average to adjust the capacity links in the GRID model topology and the most current year of expenses.

Q. Please explain why non-firm transmission should be modeled the same as short-term firm transmission.

A. The Company purchases and uses short-term firm and non-firm transmission in the same way. The only difference is that the transmission providers offer certain amounts of transmission capacity as firm products, and the rest is non-firm and have the possibility of being cut for reliability of the transmission system. The Company purchases non-firm transmission in the same way as the short-term firm transmission so that the expenses are incurred whether the amount of transmission capacity purchased is fully utilized or not. As a result, the Company has combined the short-term firm and non-firm transmission, and modeled all the short-term transmission capability based on a four-year average of the historical purchases of transmission, and the expenses in the base period of the current filing.

Q. What is the impact on NPC of including non-firm transmission in GRID?

A. Including non-firm transmission using an approach that is consistent with the modeling of short-term firm transmission increases west control area NPC by $1.2 million.

Model Intra-hour Wind Integration Costs in GRID (ICNU Adjustment 11)

Q. Please explain ICNU's proposed adjustment related to the overall modeling of wind integration costs.

A. ICNU argues that the Company should model wind integration directly in GRID, rather than calculating wind integration costs separately and making a financial adjustment to NPC. ICNU also criticizes the wind integration study that the Company used to calculate NPC in its Initial Filing, and complains that parties do not have enough time to review the Company's updated wind integration study in this proceeding. ICNU's modeling of wind integration in GRID results in a $0.6 million decrease to west control area NPC.

Q. Does the Company agree that modeling intra-hour wind integration in GRID is an appropriate approach?

A. Yes, and the Company plans to model intra-hour wind integration in GRID in future proceedings in Washington.

Q. Do you agree with ICNU's method for modeling wind integration in GRID in this proceeding?

A. No. However, the Company agrees that the parties do not have enough time in this proceeding to evaluate the new wind integration study. Therefore, the Company proposes a compromise approach that would reflect the cost of modeling intra-hour wind integration in GRID as calculated by ICNU, but would defer the decision on the proper modeling of wind integration in GRID to a future proceeding in which all parties have the opportunity to thoroughly evaluate modeling proposals.

Q. What is the compromise approach you propose?

A. To reflect the value of ICNU's adjustment in the updated NPC, the Company proposes to accept ICNU's adjustment of $0.6 million on a west control area basis.

Q. What does Staff say about the overall calculation of Company's wind integration costs?

A. Although Staff questions the reliability of the Company's wind integration costs, Staff did not include an adjustment to the Company's overall wind integration costs. Staff proposed four specific adjustments to wind integration costs that I respond to in the section of my testimony related to contested adjustments.

Planned Outage Schedule (ICNU Adjustment 16)

Q. Please describe the adjustments to planned plant outages proposed by ICNU.

A. ICNU agrees with the use of a four-year average to calculate planned outages, but contests the timing the Company modeled for its planned outages and substitutes its own planned outage schedule.

Q. What are the key elements of ICNU's proposal?

A. ICNU proposes to move the Colstrip outages to spring from fall and proposes to keep the Hermiston outage in the spring, but move it from 2011 to 2012. ICNU's proposed changes result in a $1.9 million decrease to west control area NPC.

Q. Do you agree with the adjustment that ICNU is proposing?

A. With respect to the change to the Colstrip schedule, yes. The Company does not agree with the change to the Hermiston schedule. Moving Colstrip unit 4's planned outages reduces west control area NPC by approximately $540,011.

Q. Why do you oppose ICNU's adjustment to the Hermiston schedule?

A. First, Mr. Falkenberg argues that he placed the Hermiston outage during a period of time when the economics of running the plant are least attractive. His recommendation is primarily driven by the expiration of the below market natural gas contract in June 2011. I understand that the Commission has previously found that it is not reasonable to assume that maintenance is timed to coincide with the period of lowest wholesale prices.[1]

Second, it is unreasonable to assume that the Hermiston facility can go without a planned outage in 2011, or that the planned outage should be moved from April and May of 2011—the time of the spring runoff—to February and March of 2012 when winter peak loads can occur in the Pacific Northwest.

Third, after stating that historical outage schedules do not provide the best guidance for scheduling planned outages, Mr. Falkenberg argues that his proposed change to the Hermiston planned outage timing is consistent with actual outages in prior years.

The Commission should reject ICNU's modeling assumption to base the timing of the Hermiston planned outage on an arbitrary choice of the lowest-cost period, a proposal that is designed around the expiration of the below-market natural gas supply contract.

[1] Docket No. UE-050482, Order No. 5 at 42 (Dec. 21, 2005).

Company Responses to Contested Adjustments

GRID Sales Margins (ICNU Adjustment 1, Staff Adjustment)

Q. What have Staff and ICNU proposed with respect to arbitrage sales margins?

A. Staff and ICNU argue that GRID does not account for margins earned on arbitrage transactions. ICNU proposes to impute a four-year average of short-term firm arbitrage profits and reduce west control area NPC by $2.6 million. Staff also proposes to adjust west control area NPC to account for arbitrage transactions by calculating the adjustment based on 90 percent of the four-year average of transactions, resulting in a $2.4 million reduction in NPC on a west control area basis.

Q. Why do Staff and ICNU claim such an adjustment is necessary?

A. Staff and ICNU argue that revenues from arbitrage and trading transactions are not included in GRID, but the transmission costs associated with such transactions are included.

Q. Do you agree that arbitrage revenues are not included in GRID?

A. No. GRID fully utilizes the transmission included in the model to make arbitrage transactions through system balancing sales and purchases. There are many hours when GRID is simultaneously purchasing power from one market and selling to a different market at a higher price. By definition, this is arbitrage. As a result, NPC are lower than they otherwise would be without these arbitrage transactions. In GRID, system balancing sales and purchases act as a proxy for future short-term firm sales and purchases, including arbitrage transaction, and are eventually replaced with real transactions. This adjustment proposes to impute arbitrage profits from historic transactions and would add arbitrage profits that are already computed by GRID. ICNU's and Staff's adjustment would double count revenues associated with these transactions. The adjustment is also a selective and inconsistent departure from normalized NPC modeling.

Q. Have any other jurisdictions adopted this adjustment?

A. No. Mr. Falkenberg proposed this same adjustment on behalf of the Utah Committee of Consumer Services in PacifiCorp's 2007 rate case in Utah, Docket No. 07-035-93, but withdrew it following the Company's rebuttal. The Oregon Commission imposed an adjustment that included both short-term trading and arbitrage; not arbitrage alone as is proposed in this case.

West Control Area Allocation Methodology Adjustments (ICNU Adjustments 3, 4, 7, and 8; Staff's Idaho PTP Adjustment)

Q. Why do you characterize these adjustments as "West Control Area Allocation Methodology Adjustments"?

A. The four ICNU adjustments referenced—ICNU Adjustments 3, 4, 7, and 8—and Staff's adjustment to the Idaho point-to-point contract all address allocation of costs and benefits between PACE and PacifiCorp's western system (PACW). The fundamental question raised by these adjustments is whether it is appropriate to implement ad hoc adjustments to the Company's WCA inter-jurisdictional cost allocation methodology for Washington that the Commission approved in 2007.[2] The Company requests that the Commission find that any changes to the WCA should be implemented only after an overall and thorough review of the

[2] *Wash. Utilities and Transp. Comm'n v. PacifiCorp*, Docket No. UE-061546, Order 8 (June 21, 2007).

methodology, not on an ad hoc basis. The Commission should therefore reject ICNU's and Staff's proposed changes to the WCA until after the five-year evaluation period ordered by the Commission in Order 8 in Docket UE-061546 expires and the parties have an opportunity to conduct a thorough evaluation of the methodology.

Q. Please provide some background on the Commission's adoption of the WCA methodology.

A. In Order 8 resolving PacifiCorp's 2006 general rate case, Docket No. UE-061546, the Commission approved PacifiCorp's proposed WCA inter-jurisdictional cost allocation methodology for Washington. The Commission approved the methodology for a five-year trial period and subject to an oversight committee.[3] The committee was charged with developing refinements to the WCA for consideration in future proceedings.[4]

The WCA includes loads and resources in California, Oregon, and Washington, and resources outside of California, Oregon, and Washington for which transmission is available to provide delivery to Washington customers.[5] The method isolates costs associated with assets and contracts in the west control area and allocates a proportionate share of the costs to Washington based on Washington's proportion of the west control area's demand and energy requirements.[6]

The Commission's adoption of the WCA method included Staff's

[3] *Id.* at 13.
[4] *Id.* at 14.
[5] *Id.* at 13.
[6] *Id.*

proposals to impute benefits to the WCA from market sales to PACE considering transmission availability and market prices; and modify the allocation of fixed production costs in certain allocation factors.[7]

Q. Why do ICNU's adjustments to PACE sales and transmission costs and Staff's adjustment constitute changes to the WCA methodology?

A. Staff's and ICNU's adjustments would require a change to the allocation of costs and benefits under the WCA allocation methodology, which is exactly the exercise the Commission completed in evaluating PacifiCorp's WCA proposal in 2007. It is not appropriate to make such adjustments without a thorough evaluation of the WCA methodology.

Q. Is the Company's modeling of the PACE market and transmission costs in this case consistent with the Company's practice since the Commission adopted the WCA methodology?

A. Yes. The Company has proposed the same modeling of the PACE market and transmission costs that it has been using since the Commission adopted the WCA methodology.

Q. Are you a member of the WCA oversight committee that the Commission implemented in Docket UE-061546?

A. Yes.

Q. Has ICNU or Staff raised their proposed adjustments to the WCA methodology with the oversight committee?

A. No.

[7] *Id.* at 13-14.

Q. Even if it were appropriate to include ad hoc adjustments to the WCA methodology in this case, are ICNU and Staff's proposals flawed?

A. Yes. ICNU calculated its Adjustment 3 to the eastern market modeling outside of GRID in a manner that ignores the impact of serving the assumed sale. If this adjustment is accepted by the Commission, it should be modeled in GRID. In addition, ICNU proposed to adjust wheeling expenses from the Colstrip plant, but allows the energy that passed through the transmission to the east side.

Q. Are there any technical problems with ICNU's Adjustment 4?

A. Yes. ICNU's adjustment to the modeling of the PACE market fabricated a shortage of energy on the east side of the Company's system, a situation that would not occur but for ICNU's arbitrary modeling adjustments. Based on ICNU's adjustment, the west receives a profit because of the fabricated shortage created in GRID by ICNU. ICNU supports this adjustment with only five lines of testimony and does not explain the basis for the modeling changes that seem to cut off transmission between resources and load centers in PACE or why it is reasonable to assume that PACE would let itself run out of power if it were separated from PACW. There is no basis for this adjustment and the Company recommends that the Commission reject it.

SMUD Contract Delivery Pattern (ICNU Adjustment 6, Staff Adjustment)

Q. How do Staff and ICNU propose modeling the SMUD call option sales contract?

A. Staff and ICNU propose substituting actual data for normalized data for the Company's sales contract with SMUD. For normalized purposes, the GRID model assumes that the counterparty who controls the call options on the SMUD contract will maximize the value of the contract and take the power at the most economical time. Staff and ICNU propose to adjust this input to reflect actual historical contract operation. Under Staff's calculation, this adjustment would result in a $2.5 million reduction in west control area NPC, while ICNU's adjustment would result in a $2.1 million reduction.

Q. Why do Staff's and ICNU's calculations of the adjustment differ?

A. ICNU uses the GRID model to calculate the adjustment and Staff does not.

Q. Do you have any general comments about this proposed adjustment?

A. Yes. This adjustment embodies an approach of optimizing flexible resources when it lowers NPC and not optimizing flexible resources when it raises NPC. It is based on the assumption that the Company acts rationally and other companies act irrationally. Staff's and ICNU's proposal violates any reasonable principles of consistency and fairness. If NPC are to be set using an optimization model, then all resources and contracts that are subject to being optimized should be.

Q. Please explain.

A. The proposed adjustment departs from modeling power costs on a normalized basis. If this type of modeling adjustment was adopted, then consistency and fairness require its application to all other flexible purchase or sale contracts that are modeled in a similar fashion to the SMUD contract. For that matter, it should also be applied to flexible generating resources. Optimization of the Company's system operations decreases NPC on a net basis. Staff and ICNU have not proposed "deoptimization" across the board, which would increase NPC and potentially undermine ICNU's arguments on GRID commitment logic. Nor have Staff or ICNU provided any justification for selective "deoptimization" of only one call option sales contract, rather than all purchase and sale contracts and flexible generating units.

Q. Why is it important to treat third party contracts the same whether the Company is selling or purchasing energy?

A. Use of any delivery patterns other than optimized delivery patterns will always lower net power costs for wholesale sales contracts with flexibility such as the SMUD contract. The opposite is true for purchased power contracts, such as the BPA purchase contract, that give the Company flexibility in how the power is taken. It is not fair or consistent to normalize different contracts using different rules.

Q. How do you respond to ICNU's argument that flexible wholesale sales contracts should not be optimized because the Company has not modeled any of the constraints, forward price curves, or loads used by the counterparties?

A. It is correct that the Company does not model counterparties' systems due to the impossibility of obtaining the data that are proprietary to those counterparties. However, given that the Company is only one of the many participants in the market, the only assumption is to assume that all the participants in the same market are rational and will exercise their rights to the flexible contract to lower their costs.

Q. ICNU argues that the BPA purchase contract should be optimized because the actual market prices that occurred in the past are unlikely to match the normalized pattern of forecast market prices. How do you respond?

A. This proves my point. ICNU's argument should apply equally to sales contracts. The actual market prices that SMUD will be evaluating during the test year will also vary from actual market prices incurred in the past, so ICNU's argument is just as applicable to the sales contract to which ICNU is seeking to apply historical data.

Q. Are there other practical problems with Staff's and ICNU's proposal?

A. Yes. Actual delivery patterns can be misleading. Both for the Company and other utilities, forward price curves and system conditions will be different in the test period than they were in the past. If there is an option to model a contract in GRID, that should be preferred over using actual historic data. Whether the Company or another party is in control of when to take the energy is beside the point. The actual conditions under which the rights to the contracts are exercised could be very different from what were assumed in the optimization model. As a result, when the model-optimized deliveries of energy do not match actual historical deliveries of energy, it does not suggest that the actual deliveries were not optimized against the same considerations as in the model.

Q. ICNU argues that the Company models other delivery patterns and uses contract inputs based on actual data. Is this a fair point?

A. No. It is inappropriate for ICNU to use the Company's modeling of non-flexible contracts with GP Camas, small purchases, and reserve requirement inputs to justify its adjustments to the call option sales contract. None of those contracts provides the kind of flexibility that is provided for in the terms of the call option contracts. This is simply another argument for selectively using the historical data when it reduces NPC.

Q. Do the historical data display SMUD's preference as to when to take energy under the contract?

A. Yes. In addition to the firm energy, SMUD also has the right to take provisional power under the terms of the contract, which will be returned in full to the Company the following year. For the normalized calculation, the Company assumes the take and return of the provisional power are equal and matching in the test period. When both the firm and provisional portions of the sales contract are taken together, it is clear that SMUD intends to take energy with preferences by season. Exhibit No. ___ (GND-9) shows the monthly pattern of the total firm and provisional sales in a four-year period. Based on the historical pattern, it would be reasonable to assume that without the flexibility of the provisional portion of the contract, SMUD would shape their take of the firm portion with similar seasonal pattern. ICNU's proposal only considered the firm portion of the contract and suggested that SMUD would take more energy in Spring than in Fall as if SMUD would not have considered their rights to the provisional energy.

Q. ICNU criticizes the concept that the provisional clause should be considered when evaluating the modeling of the SMUD contract. Do you agree with ICNU's arguments in favor of ignoring this clause?

A. No. It is as much a part of the contract as the firm sale and provides evidence that

SMUD acts rationally under the contract by minimizing their costs within the flexibility parameters of the contract. The Company's evidence looks at delivery under the whole contract which is the only realistic approach.

Q. What does the Company recommend for modeling wholesale contracts?

A. The Company recommends that the Commission make its decision based on the principle of equity in the treatment of wholesale purchase and sales contracts. Under this approach, the Commission would either allow all option sales and purchase contracts to be optimized by GRID within the terms of the contracts, as the Company has done in Washington in the past, or model all options sales and purchase contracts using four years of historical delivery patterns. It is the Company's strong preference that the Commission continue with its historical modeling practice of optimizing all call option wholesale contracts.

Q. Is there a way to reflect actual delivery patterns of call option contracts in NPC?

A. Yes. A power cost adjustment mechanism, which ICNU has opposed in the past, would allow the Company to reflect actual delivery patterns of these contracts in NPC.

DC Intertie Costs (ICNU Adjustment 9, Staff Adjustment)

Q. Please explain Staff's and ICNU's proposed adjustment to costs associated with the DC Intertie.

A. Staff and ICNU argue that costs associated with the DC Intertie and Network Transmission Agreement between BPA and the Company should be removed from NPC on the basis that no purchases are modeled at the Nevada-Oregon

Border (NOB), the point from which the agreement provides wheeling. Both Staff's and ICNU's proposed adjustment would result in a $4.8 million decrease to west control area NPC.

Q. Please provide some background on the DC Intertie contract.

A. The DC Intertie contract was executed 16 years ago on May 26, 1994, to provide deliveries of 200 megawatts of power from Southern California Edison at NOB under Amendment 1 to the Winter Power Sales Agreement (WPSA). The WPSA was executed on December 14, 1993 and provided up to 422 MW of power to be delivered to the Company's west control area. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222 megawatts of power into the west control area. The agreement provided that if the Company procured additional transmission rights by June 1, 1993, then it could import the remaining 200 megawatts to its system. The Company secured the remaining 200 megawatts of transmission rights by acquiring 200 megawatts of transmission capacity on the DC intertie. The Company terminated the WPSA effective January 1, 2002, but kept its 200 megawatts of DC Intertie import rights.

Q. How does the DC Intertie contract benefit the Company's customers today?

A. The agreement takes advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest. The contract provides a valuable means of securing capacity and energy from California entities to meet retail loads. Loads in California are relatively low in the winter when loads in the Company's west control area and the rest of the Pacific Northwest are at their highest.

Q. But there are no transactions modeled at NOB in the test period in this proceeding. Why is it appropriate to include costs related to the DC Intertie agreement in this proceeding?

A. In making their proposal, Staff and ICNU focus on energy deliveries under the contract rather than the capacity and diversity benefits of the contract. It would be inappropriate to penalize the Company for prudently acquiring transmission rights 16 years ago by disallowing costs today based on hindsight and only looking at the energy value of a resource that can facilitate the delivery of both capacity and energy. By purchasing these transmission rights, the Company has purchased assurance that it can reliably serve its retail customers loads. Staff's and ICNU's proposals based on their limited energy-only view of this contract is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds under an insurance policy. The costs associated with this contract are modest in light of the benefit to the Company's overall transmission strategy and hedge against changes in the market.

Q. How should the Commission judge the prudence of this contract?

A. Prudence should always be judged based on the information that was known at the time the contract was executed. It would not be reasonable to judge a 16-year old contract based on information that is available today that was not available 16 years ago.

Q. Has the Commission rejected similar proposals by ICNU to disallow a contract that has been included in rates for many years?

A. Yes. In an order issued on April 17, 2006 in a 2005 PacifiCorp proceeding, Docket UE-050412, the Commission rejected ICNU's proposal to adjust the cost of the Western Area Power Administration (WAPA) contract that Utah Power entered into in 1962. The Commission found that it was difficult to assess the prudence of a contract 43 years after it was signed, because circumstances facing utility decision makers in 1962 were very different from those facing utilities today. The Commission found that under this situation, it required, at a minimum, substantial evidence that the utility acted imprudently at the time of the contract.

In an order issued on June 21, 2007 in PacifiCorp's 2006 rate case, Docket UE-061546, the Commission similarly rejected ICNU's proposal to adjust the cost of the SMUD contract. The Commission noted that the contract was 20 years old and no party had found the contract to be worthy of attention during that time. The Commission noted that "[p]rinciples of fairness suggest that a party aware of facts that raise questions of prudence should raise the issue sooner rather than later when there is an opportunity to do so." The Commission again found that a substantial showing would be required for a party challenging a contract entered into many years ago.

Q. How would the Commission's position on raising an objection to contracts entered into many years ago apply to this adjustment?

A. The Commission should require ICNU to show substantial evidence that the utility acted imprudently at the time they entered into the contract. ICNU has not done so, and ICNU's proposed adjustment should therefore be rejected.

Wind Integration

Non-Owned Wind Integration Costs (ICNU Adjustments 13-15; Staff Adjustments to the Non-SCL Owned Stateline Wind Farm, Campbell Wind Farm, Oregon QFs, and SCL Stateline Wind Farm Intra-hour Costs)

Q. What have Staff and ICNU proposed with respect to the non-SCL owned Stateline wind project, the Campbell wind project, and Oregon QF wind projects?

A. Staff and ICNU propose that the Commission disallow costs associated with integrating non-owned wind plants that are interconnected to the Company's transmission system, even though the Company is required by its FERC Open Access Transmission Tariff (OATT) to integrate these wind facilities. Staff's adjustment to intra-hour costs for these facilities would result in a decrease to west control area NPC of $4.1 million. ICNU's adjustment would result in a $2.3 million decrease to west control area NPC.

Q. Why do Staff and ICNU propose disallowing intra-hour wind integration charges associated with these facilities?

A. Staff and ICNU argue that wholesale wind generators that cause the Company to incur integration costs should pay for these costs, not retail customers, and that retail customers do not benefit from these wind projects since none of the output is used to serve the Company's loads. ICNU acknowledges that the Company is prohibited from charging for these services under its FERC-approved OATT, but argues that the costs should be excluded because the projects provide no energy to Washington customers.

Q. Why doesn't the Company charge generators for wind integration resources such as the Stateline and Campbell wind facilities?

A. PacifiCorp could not charge wholesale transmission customers for this type of service without FERC approval of a Company rate application proposing a new wind integration charge. The Company is required by federal law to interconnect with new facilities under the terms of its OATT.

Q. Are there barriers to charging non-owned wind facilities for wind integration costs?

A. Yes. Modifying the OATT to impose wind integration charges on only non-owned wind facilities would violate the federal statutory mandate that PacifiCorp treat all transmission customers, affiliated and non-affiliated, on a not unduly discriminatory basis. In addition, there is little regulatory guidance from FERC in this area with respect to what FERC will ultimately consider to be an adequate proposal for a wind integration charge. Although FERC conditionally accepted a proposal by Westar to add a new Schedule 3A charge, whereby all variable generators located within Westar's balancing authority area pay a regulatory service fee for power exported outside of the balancing authority area, recently, FERC rejected Puget Sound Energy's proposed revision to its OATT to add a new charge applicable to all wind generators for wind integration within-hour generation following service. In each case, wind industry advocates vigorously protested the proposed tariff revisions because, among other protests, the proposed charges constituted significantly higher regulatory service fees to intermittent resources than for dispatchable resources.

Q. Does the Company plan to raise this issue in its next FERC rate case?

A. Yes. The Company plans to file a rate case with FERC no later than June 1, 2011, in which the Company will include a proposed wind integration charge in its transmission tariff rates, pending any FERC guidance on the issue. The Company completed a wind integration study in conjunction with its 2010 Integrated Resource Plan (IRP) and is in the process of reviewing comments from parties regarding the study. It is hoped that the study can be used in the development of a wind integration charge to be proposed to be added to the OATT, however, no determination has yet been made. The Company is closely tracking all development at FERC related to wind integration and is bound to follow any guidance that FERC may issue in this regard.

Q. Are the costs associated with wind integration a prudent expense?

A. Yes. As a balancing area authority, PacifiCorp must operate its balancing area by matching system resources to actual load fluctuations on a second-to-second basis through automatic generation control. Maintaining system balance is one of the key functions of a balancing area authority who is required to maintain system reliability including maintaining system frequency. Load fluctuations, outages, and generation output fluctuations all contribute to the need for balancing resources. The addition of renewable resources such as wind has the tendency to increase the need for balancing resources.

Q. What are the benefits to the Company's customers of providing such services to the non-owned generation?

A. As a balancing area authority, PacifiCorp owns and operates an extensive transmission network and it is required to operate safely and reliably for all of its customers, keeping all resources and loads in balance on a moment-to-moment basis. In addition, the Company is mandated to make its transmission network available to all generators in an open access and non-discriminatory fashion. By providing wind integration services in addition to other transmission related services as a balancing area authority, the Company ensures that its customers are served by a reliable system and with diverse resources. Moreover, any transmission revenues received from non-owned generation, which pays wheeling to the Company, are credited against retail rates and, therefore, have the effect of lowering retail rates.

Q. ICNU argues that BPA charges PacifiCorp for wind integration services and therefore the Company should likewise charge non-owned wind facilities for the provision of the same services. Is this a valid argument?

A. No. The comparison of PacifiCorp and BPA is inapt. FERC has no jurisdiction to determine if BPA's rates are discriminatory, nor is BPA bound by the same non-discrimination standard that applies to the Company.

Q. Do ICNU and Staff raise any other objections to wind integration costs associated with the Campbell wind facility?

A. Yes. ICNU and Staff object to the Company's modeling of the Campbell wind project based on the capacity factor and profile information of the Stateline wind project, which is in close proximity with the Campbell wind project. ICNU and Staff argue that the costs associated with the Campbell wind project are therefore not known and measurable.

Q. Do you agree?

A. No. The key variables necessary to model the costs associated with the wind facility—size and location—are available to the Company. Because the Company is not the owner of the facility, it does not have available to it the capacity factor. Using the specifications of a wind facility in close proximity to the Campbell wind facility to model additional variables is reasonable and known and measurable.

Q. Has Staff proposed an additional adjustment removing the intra-hour costs associated with the SCL portion of the Stateline wind project?

A. Yes. Staff states that wind integration costs associated with the SCL Stateline wind project should be removed from rates because the exchange contract with SCL terminates at the end of the rate year and actual costs of wind integration are uncertain.

Q. Is Staff's adjustment to the SCL Stateline wind integration costs reasonable?

A. No. Staff's adjustment is inconsistent with Staff's proposal to include the SCL Stateline contract in NPC. The Company accepts Staff's adjustment to keep the SCL Stateline contract in NPC. The wind integration costs for this contract should also remain in NPC based on the principle of matching.

Forced Outages Modeling Issues

Colstrip Outage (ICNU Adjustment 17, Staff Adjustment)

Q. Please explain ICNU's and Staff's adjustment based on the Colstrip 4 outage in 2009.

A. In 2009, the Company's coal plant, Colstrip 4, experienced an unplanned outage of 166 days. ICNU and Staff propose adjusting the Company's forced outage rate to account for this outage. ICNU caps the Colstrip 4 outage at 28 days, which results in a $1.7 million decrease to west control area NPC. Staff used an eight percent outage rate to Colstrip 4 to calculate the amount of additional average monthly energy that would be available from Colstrip 4 and multiplied that amount by the difference between the monthly average market price for the test year and the incremental cost of Colstrip 4 generation. Staff's adjustment results in a $1.5 million decrease to west control area NPC.

Q. Do either Staff or ICNU allege that the Colstrip 4 outage was a result of imprudence?

A. No, neither party has alleged that PacifiCorp was impudent with respect to the outage.

Q. Why do you object to ICNU and Staff's proposals related to the Colstrip 4 outage?

A. Both proposals would result in an abnormally low outage rate in the test year. It would be inappropriate and unfair to penalize the Company for a prudent outage by imputing an abnormally low outage rate in the test year, especially when the Company does not have a power cost adjustment mechanism and did not seek recovery of costs associated with the outage through a deferred accounting application.

Q. Has the Commission previously adopted the 28-day outage standard that ICNU proposes or the methodology that Staff proposes?

A. No. To my knowledge, the Commission has used actual forced outage rates in setting NPC in the past and has not adopted ICNU’s or Staff’s proposals.

Q. Why is it appropriate to include the Colstrip 4 outage in the calculation of forced outages in this proceeding?

A. While forced outages of the extent experienced at Colstrip 4 in 2009 are unusual, they do happen. Removing all extended outages creates an inaccurate picture of forced outage rates, skewing them downward. Just as the Company may experience unusually high forced outage rates in some years, it will experience unusually low forced outage rates in others. For example, during the 4-year historic period used to develop force outage rates, Colstrip 4 experienced a period of 174 days without any outage. It is unfair to selectively remove data that would lower forced outage rates and thereby eliminate the opportunity for the forced outage rates to fluctuate with actual data. With no showing that the Company’s forced outage rates are higher than they should be because of imprudence, it is inappropriate to remove the Colstrip 4 outage rate.

Q. Do you have additional comments on the basis of Staff’s adjustment?

A. Yes. Staff’s proposed adjustment seems to be based on the settlement agreement with Avista. Realizing that the Company does not have a power costs adjustment mechanism in Washington where the reviews for prudence typically happen, Staff made an adjustment to lower the forced outage rates nonetheless.

Other NPC Adjustments

Jim Bridger Fuel Deration (ICNU Adjustment 18)

Q. Please explain ICNU’s proposal related to the fuel at the Bridger Plant.

A. ICNU argues that the quality of fuel at the Bridger Plant has resulted in an unnecessarily high number of derations at the plant. ICNU argues that additional costs resulting from fuel quality problems at the Bridger Plant be disallowed, resulting in a $1.1 million decrease to west control area NPC. ICNU also proposes to remove $1.8 million related to management bonuses, employee meals and gifts, and donations associated with the Bridger Plant. I address the portion of ICNU's adjustment related to fuel quality derations, while Erich Wilson addresses the portion of the adjustment related to employee costs.

Q. Do you agree that the fuel quality at the Bridger plant results in additional derations compared with the derations experienced at the other plants?

A. Yes. However, unlike natural gas or diesel fuel, coal is not a homogenized commodity. All coal plants are affected by changes in coal quality and their ability to blend coals. Coal quality can vary dramatically from seam to seam or within a seam. Through blending of coals, both the Bridger mine and the Bridger plant minimize quality variations that undermine optimal plant performance. Although the mine does attempt to deliver a consistent product, at times it is limited by the size of the stockpiles and physical logistics.

Q. Please explain.

A. Bridger mine's surface operation historically delivered a consistent coal blend through mining of coal in multiple exposed pits. With the development of the underground mine and the scaling back of the surface operation, Bridger mine has less capacity to blend coal. The inherent quality variability in the underground mine will likely pose future blending challenges. Blending facilities at the location of the plant enable the Company to mix coals as necessary to provide the power plants with a consistent coal quality. These facilities allow the Company to efficiently and economically segregate, stockpile, and reclaim underground coal based on a particular coal quality. Without such a facility at the Bridger Plant, both the Bridger mine and the Bridger plant are potentially limited at times in their ability to blend Bridger underground coal during periods of high ash and low heat content.

Q. Is Bridger Coal evaluating options to improve its blending capabilities?

A. Yes. The Bridger mine currently has stacking tubes adjacent to the underground portal that partially alleviate the quality fluctuations. To further minimize plant derations, the mine is evaluating creating a surface inventory surge area that can accommodate the expected coal quality variability.

Q. Do you agree with ICNU that costs associated with the additional derations should be removed from NPC?

A. No. The Company's Bridger coal provides a source of fuel for the plant that on an overall basis results in a lower fuel cost for the plant. It is inappropriate to remove costs associated with "low-quality" coal from the underground mine, but accept the lower coal costs that result from the favorable economics associated with underground mining. In addition, ICNU incorrectly assumes that the total costs at the Bridger plant would not change from what the Company has included in its filing even though the generation at the plant has increased due to removal of the outages due to "low-quality" coal.

Q. What impact would increasing tbe ratio of surface coal to underground coal have on Bridger Coal deliveries?

A. Increasing surface production at the expense of the underground production would likely result in lower ash coal deliveries but certainly at a much higher costs.

Minimum Loading and Deration (ICNU Adjustment 19)

Q. How does the Company apply the deration method?

A. The Company's approach derates the maximum capacity of the unit in every hour of the year by an equal percent based on historic forced outage rates, which constitutes a "haircut" in unit availability.

Q. How would ICNU's proposal change this method?

A. ICNU's approach would alter thermal units' heat rate curves to artificially increase their efficiency as compared with the heat rate curves that are developed from actual plant operating data. In addition, ICNU proposed to reduce thermal plant minimum generation levels so GRID can run thermal units at levels they are physically incapable of reaching.

Q. Would ICNU's proposed method significantly understate the heat rates?

A. Yes. The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at one particular level of generation—its derated maximum capacity, with the assumption that the unit would have otherwise been dispatched at its stated maximum capacity in GRID if there were not the availability "haircut". When the unit is dispatched at any level below its derated maximum capacity, GRID has made the optimal decision to dispatch that unit at a lower and less efficient generation level, whether it has been derated or not. Therefore, derating the entire heat rate curve overstates the efficiency of the unit and understates the heat inputs.

Exhibit No.___(GND-10) and Exhibit No.___(GND-11) show the heat rate curves that would be under the methods modeled by the Company and proposed by ICNU for a coal-fired unit and gas-fired unit, from minimum to maximum generation level, with the assumed generation levels superimposed on the heat rate curves that would be dispatched under the Company's methods. The exhibits clearly demonstrate that heat input required for various levels of generation is understated using the derate-adjusted heat rate. In both cases, there are many hours of dispatch below the derated maximum capacity, which are the generating levels at which ICNU's proposal would understate the heat rate, and subsequently understate NPC.

Q. Does this suggest that the Company should adjust the heat rates at least to the derated maximum capacities of the units?

A. No. The Company uses the "haircut" to adjust down a unit's capacity that is still at a relatively efficient level. In actual operations, a unit can be derated to any level between its minimum and maximum capacities.

Q. Does it logically follow that the minimum generation level should be derated because the maximum generating level is derated?

A. No. The purpose of the "haircut" to the maximum generating capability is to reflect the amount of generation no longer available due to outages. That is fully accomplished through the "haircut" to the maximum generating capacity.

Q. Is it realistic to derate the minimum generation level of a unit for forced outages?

A. No. The minimum generation level of a unit is based on its technical specification below which it cannot operate. Reducing the minimum generation level of units below their technical capability artificially increases the operating range of each unit, thereby incorrectly reducing NPC.

Q. ICNU also argues that the Company uses ICNU's proposed method for modeling fractionally owned units, such as Bridger and Colstrip. How do you respond?

A. The Company does scale the capability of the fractionally owned units. However, in the case of outages, it is not correct to assume that another entity owns the portion of the units that are forced out. When GRID determines a certain amount of generation from a unit, it does not make the decision based on whether or how much the unit has been derated. That is, for a unit with a capacity of 100 megawatt, when GRID dispatches the unit at 70 megawatt, it does not matter whether the unit has been derated by 20% or not.

Q. Do you agree that the Company has conceded that ICNU's criticism of the Company's minimum loading and deration is valid?

A. No.

Other Adjustments

Combined Cycle O&M Adjustment (ICNU Adjustment 22)

Q. Please explain ICNU's adjustment to O&M costs of combined cycle plants.

A. ICNU states that the proposed daily screening adjustment reduces the fixed O&M

costs associated combined cycle plants.

Q. What is the basis for ICNU's adjustment?

A. ICNU provides no explanation of this adjustment. Based on ICNU's testimony on this issue in prior cases, however, ICNU could be referring to the removal of incremental O&M that the Company added to fixed O&M for each start-up of a combined cycle plant.

Q. Is ICNU's adjustment reasonable?

A. No. The Company has not included any incremental O&M to reflect the additional costs of combined cycle plant start-ups. Moreover, ICNU provides no explanation of its adjustment or evidence to support it. Therefore, there is no basis in the record for ICNU's proposal.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.