Confidential per WAC 480-07-160
Exhibit No.___(GND-1CT)
Docket UE-13____
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	Docket UE-13____
vs.	)	
PACIFICORP dba Pacific Power & Light Company	)	
Respondent.	)	

PACIFICORP

REDACTED DIRECT TESTIMONY OF GREGORY N. DUVALL

January 2013

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company).

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Director, Net Power Costs.

Qualifications

Q. Briefly describe your education and professional experience.

A. I received a degree in mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions, and trading. From 1997 through 2000, I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process. I currently direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

Purpose of Testimony

Q. Please describe the purpose of your testimony.

A. I present the pro forma net power costs (NPC) for the test period, and I explain the Company's proposed power cost adjustment mechanism (PCAM). As a preface to both discussions, I present the Company's proposed modifications to the West Control Area inter-jurisdictional allocation methodology (WCA) related to the calculation of NPC and the Company's proposed PCAM.

Q. Why are you proposing NPC-related modifications to the WCA in this filing?

A. As discussed in the testimony of Mr. R. Bryce Dalley, the Company believes that Washington should move toward an inter-jurisdictional cost allocation methodology that more closely reflects the Company's actual costs to serve customers. As an interim measure, the Company is proposing several changes to the WCA to more accurately represent the actual cost of operating as if the Company operated its PacifiCorp West Balancing Authority Area (PACW) as a stand-alone entity. The changes will increase the accuracy of the NPC forecast for the WCA and enable the calculation of actual NPC for purposes of a PCAM mechanism.

Q. Please summarize your testimony related to the Company's pro forma NPC.

A. I sponsor the Company's pro forma NPC for calendar year 2014, the approximate period when rates from this case will be in effect. This case reflects an increase in Washington NPC of approximately $7.5 million, driven by increases in wheeling costs, coal costs, and the Company's proposed change to the allocation of qualified facility (QF) contracts in the PACW, and partially offset by decreases in loads and natural gas and electric swap expenses. My testimony explains how the Company modeled NPC in this case and highlights changes designed to improve the accuracy of pro forma NPC. I also sponsor the Company's 2012 Wind Integration Study and explain how it is incorporated in the current filing. Please note that NPC referenced in my testimony are on a Washington-allocated basis unless otherwise noted.

Q. Please summarize your testimony related to the Company's proposal for a PCAM.

A. The Company is proposing a PCAM designed to address the increasing variability of the Company's NPC. There are several factors that contribute to NPC variability, including the Company's increased reliance on wind and natural gas generation resources as mandated by Washington law. The WCA also increases the Company's NPC-related risk, by making NPC a larger part of the Company's revenue requirement and increasing the Company's reliance on market purchases to meet load.

These factors, as well as constructive regulatory policy and a showing that the Company's NPC-related risk is not asymmetrically skewed toward higher prices, support the Company's proposal for a PCAM without deadbands or sharing bands. For the PCAM's true-up mechanism, the Company has proposed a method of accounting for actual NPC that relies upon the Company's per books data. The Company's proposed NPC-related revisions to the WCA facilitate the calculation of actual NPC by tying NPC more closely to the Company's actual PACW costs.

PROPOSED MODIFICATIONS TO THE WCA

Q. Is the Company proposing changes to improve the accuracy of modeling NPC using the WCA?

A. Yes. The Company has identified the following NPC-related enhancements to the WCA:

- Inclusion of all costs and benefits associated with all PACW (Oregon, California, and Washington) QF contracts in the calculation of NPC, with an allocated share of each assigned to Washington;
- Inclusion of all costs and benefits associated with the full capacity of the 200 megawatt (MW) point-to-point wheeling contract with Idaho Power Company; and
- Exclusion of the assumed sale to the PacifiCorp East Balancing Authority Area (PACE).

Q. Why is the Company proposing NPC-related changes to the WCA in this case?

A. As discussed in more detail in the testimony of Mr. Dalley, this case includes an evaluation of the WCA. In the long-term, the Company believes that Washington should implement a new methodology based on how the Company actually operates its system. Because the development of an acceptable methodology will take time, the Company proposes changes to the WCA in this case to improve its operation. Some of these changes impact the calculation of NPC, both pro forma and actual.

Q. What was the Company's guiding principle in developing changes to the WCA for calculating NPC?

A. The Company's guiding principle was that the WCA should more accurately represent the actual cost of operating as if the Company operated PACW as a stand-alone entity, without assumed inclusion of benefits that don't exist or exclusion of costs that do. The proposed changes to the WCA will increase the accuracy of pro forma NPC and enable the calculation of actual NPC for purposes of a PCAM mechanism.

Inclusion of All Costs and Benefits Associated with All PACW (Oregon, California, and Washington) QF Contracts in the Calculation of NPC, with an Allocated Share of Each Assigned to Washington

Q. Please explain the Company's proposed change to the WCA for QF contracts in the PACW.

A. In previous filings using the WCA, the Company included only QF contracts physically located in Washington. Beginning with this filing, the remaining PACW QF contracts—located in Oregon and California—are included in the definition of WCA resources. This is a logical extension of the WCA because these resources are all located within PACW, physically deliver power to meet Washington load in the same manner as any other PACW resource, and provide direct benefits to Washington customers.

Q. Why is this change to the WCA warranted?

A. All QF contracts in PACW are resources that physically deliver power to meet Washington load in the same manner as any other PACW resource. Most of the QF contracts included in this case have been executed or renewed recently at current avoided cost prices. Like other PACW resources, QF contracts are used and useful in serving Washington customers. Excluding these resources from Washington rates is contrary to the policies underlying the Public Utility

Regulatory Policy Act of 1978 (PURPA) and effectively denies the Company cost-recovery for resource acquisitions mandated by federal statute.

Q. Are there a material number of QF contracts now serving Washington customers that are not currently reflected in Washington rates?

A. Yes. Collectively, PACW QF contracts provide a significant source of power supply to Washington customers, who currently pay only a portion of the costs of these resources. The proposed change to the WCA to include all PACW QF contracts increases Washington NPC by $10.7 million.

Q. Do other Washington utilities include the costs of QF contracts, including QF contracts from other states, in Washington rates?

A. Yes. In the most recent cases for Puget Sound Energy, QF contracts were included in rates at an average price of $73 to $97 per megawatt-hour (MWh). Rates for Avista also include costs for QF contracts, including an allocated share of the cost of various QF contracts located in its Idaho service territory.

Q. How are the prices paid under PacifiCorp's QF contracts determined?

A. Prices paid to QFs are determined based on a utility's avoided cost of energy and capacity, in compliance with PURPA. Each state has an approved method for calculating these avoided costs, and the resulting prices are heavily scrutinized and ultimately approved by the respective commissions. The avoided cost calculation is designed to set QF contract prices at a level where customers are indifferent between a utility purchasing from the QF or obtaining energy and capacity from the next available resource.

Q. Are any Washington QF contracts currently included in rates?

A. Yes. In PacifiCorp's 2011 general rate case, docket UE-111190 (2011 Rate Case), three QF contacts were included in NPC at an average price of $118.83 per MWh. Additionally, there are some expiring QF contracts that are in various stages of being renegotiated or replaced by new QF contracts. The Company proposes to update NPC for additional signed QF contracts in its rebuttal filing.

Q. What is the average price of the Oregon and California QF contracts included in this case?

A. The weighted average price of the Oregon and California QF contracts in this case is approximately $77.20 per MWh.

Q. How does the Company treat QF contracts in other states?

A. Under the 2010 Protocol inter-jurisdictional allocation methodology used in the Company's other five state jurisdictions, all QF contracts are treated as system resources and allocated system-wide. The 2010 Protocol provides that if the cost of a particular QF contract executed after September 2010 is determined to exceed the costs PacifiCorp would have otherwise incurred acquiring comparable resources, then the costs exceeding the cost of the comparable resource will be situs assigned to the home state. However, no QF contract has ever been determined to be priced above comparable resources, including the Oregon and California QF contracts in this case.

Inclusion of All Costs and Benefits Associated with the Full Capacity and Cost of the 200 MW Point-to-Point Wheeling Contract with Idaho Power Company

Q. Please explain the treatment of the 200 MW point-to-point wheeling contract with Idaho Power.

A. As a result of the Commission order in the Company's 2010 general rate case, docket UE-100749 (2010 Rate Case), 50 percent of the cost of the Idaho Power 200 MW point-to-point wheeling contract was assigned to the WCA.[1] In that case, the transmission capacity had been reduced by 100 MW to reflect the Company's ability to dynamically schedule and the ability to transfer reserve capability from west to east.

In this case, the Company restored the full 200 MW of transmission capacity, which allows additional output from the Jim Bridger plant to be moved to the west, and the Company included the full cost of the 200 MW point-to-point contract in wheeling costs. Washington wheeling expense is increased by approximately $0.5 million, but the overall impact is a net reduction in Washington NPC of approximately $0.2 million due to the additional low-priced energy available from the Jim Bridger plant. The additional capacity increases the WCA proportion of the Jim Bridger plant output from 96.5 percent to 99.4 percent. As presented in the direct testimony of Mr. Steven R. McDougal, this ratio is applied to the fixed costs of the Jim Bridger plant.

[1] *Wash. Utils & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06 (March 25, 2011).

Q. Why did the Company decide to include the entire 200 MW point-to-point wheeling contract with Idaho Power in the WCA?

A. If PACW were truly operated on a stand-alone basis as assumed by the WCA, the Company would not use dynamic scheduling to provide control to or receive control from PACE. Rather, the Company would use the full capacity to provide benefits to PACW. Including the total cost of the contract in the WCA along with its full capacity is consistent with the Commission order in the 2010 Rate Case.[2]

Exclusion of the Assumed Sale to PACE

Q. Why did the Company remove the imputed sale from PACW to PACE that exists under the current WCA?

A. The WCA is based on the assumption that PACE does not exist. Since the WCA does not recognize any transmission rights or costs outside of the WCA, GRID assumes the Company buys and sells power at markets in the WCA only—Mid-Columbia (Mid-C), California-Oregon Border (COB), and Nevada-Oregon Border (NOB). While there are limited interconnection points between balancing authority areas (e.g., Jim Bridger plant in Wyoming or the Populus substation in Idaho), there are no functioning markets at these points. There is thus no realistic basis for imputing a sale from PACW to PACE, or any foundation for modeling the size or price of such a sale.

Q. Is a sale from PACW to PACE recognized in actual NPC on the Company's books?

A. No. There is no transaction booked to account for a sale of energy from PACW to PACE. As discussed below, the Company has followed the Commission's

[2] *Id.* at 58.

directive in the Company's general rate case, docket UE-061546 (2006 Rate Case) and developed an approach to the calculation of actual NPC for its PCAM proposal that relies on per books data, not "pseudo-actual" data. This calculation does not include an imputed sale between PACW and PACE. It would be inconsistent to impute a sale in pro forma NPC only to remove it when NPC are trued-up to actual costs on the Company's books.

Q. What is the NPC impact of removing the imputed sale from PACW to PACE?

A. Removing the sale increases pro forma Washington NPC by approximately $0.3 million.

PRO FORMA NPC

Overview

Q. Please provide an overview of NPC in the Company's filing.

A. The pro forma NPC for the test period are approximately $580.6 million for the Company's PACW. As discussed in Mr. McDougal's direct testimony, the Washington NPC are approximately $131.4 million before applying the production factor.[3] NPC are determined using pro forma expenses and revenues for the calendar year 2014 (the approximate period when rates from this case will be in effect). Only costs and benefits attributed to the WCA are included, and the resulting NPC are then allocated to Washington under the WCA, revised as discussed above. A report detailing the NPC forecast on a WCA basis is attached to my testimony as Exhibit No.___(GND-2).

[3] Mr. McDougal's testimony also addresses the Company's application of the production factor in the calculation of Washington pro forma NPC.

Q. Please explain NPC.

A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. NPC are calculated for calendar year 2014 based on projected data using GRID, a production cost model that simulates the operation of the Company's power system on an hourly basis.

Q. How do the pro forma NPC in this proceeding compare to the NPC authorized in the Company's 2011 Rate Case?

A. The pro forma Washington NPC in the current proceeding are approximately $7.5 million higher than the level authorized by the Commission in the Company's 2011 Rate Case.

Q. Is the Company's general approach to the calculation of NPC using the GRID model the same in this case as in the Company's most recently completed general rate case in Washington?

A. Yes. The Company used the GRID model consistently in this case and in the 2011 Rate Case. The version of GRID used in this case is the same as used in the 2011 Rate Case. As I discuss below, the Company has made some changes to the inputs to the GRID model.

Q. What GRID inputs were updated for this filing?

A. The Company updated inputs to the GRID model to reflect the information available at the time the Company prepared the NPC study for the current filing. In addition to PACW load, the Company updated wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, transmission capability, characteristics of the

Company's generation facilities, and planned outages and forced outages of the Company's generation resources.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is the same information contained in Exhibit No.___(GND-2), and an electronic version is included as workpapers. Additional data with more detailed analyses are also available in hourly, daily, monthly, and annual formats by heavy load hours and light load hours.

Q. What are the main contributors to the increase in the pro forma NPC?

A. After removing a settlement adjustment that was included as a reduction to NPC in the 2011 Rate Case, the main contributors to the increase in NPC are an increase in wheeling expense, an increase in coal costs, and the proposed change in the treatment of PACW QF contracts described above. The wheeling expense increase is due in large part to the proposed wheeling rates recently filed by the Bonneville Power Administration (BPA). These cost increases are partially offset by lower costs due to reduced WCA load and lower net costs related to electric and natural gas swaps in the test period.

Increases to BPA Wheeling Rates

Q. Please explain the increase in NPC related to the BPA wheeling rate increase.

A. On November 15, 2012, BPA filed its 2014 Joint Power and Transmission Rate Proceeding and proposed rate changes that will increase the Company's BPA transmission expenses by roughly 15 percent. New rates are expected to take effect for the fiscal period beginning October 2013. The Company has roughly

5,000 MW of BPA transmission capacity. Point-to-Point (PTP) and Formula Power Transmission (FPT) service accounts for 83 percent of this service, and these rates are increasing by roughly 20 percent. This increase is partially offset by reductions in the rates for Network Transmission and Southern Intertie service. Including the overall impact of the filed BPA rate increase in the calculation of the Company's wheeling expenses increases Washington NPC by approximately $3.0 million.

Q. What assumptions did the Company make regarding the transmission rates proposed in the current BPA rate case?

A. The Company applied the proposed rates set forth in BPA's initial proposal.

Q. Does the Company propose to update the expenses related to all contracts with BPA?

A. Yes. The Company will update NPC on rebuttal with the final decision of the BPA rate case, currently expected in July 2013, or when better information becomes available.

Increases to Coal Prices

Q. Have test period coal prices increased from the 2011 Rate Case?

A. Yes. Compared to the final updated NPC in the 2011 Rate Case, coal prices increase Washington NPC by approximately [redacted] million.

Q. What are the key drivers of the coal price increases?

A. The [redacted] price-related increase is associated with an increase of approximately [redacted] at the Jim Bridger plant and [redacted] at the Colstrip plant.

Q. Please explain the [redacted] increase in Jim Bridger plant costs.

A. Approximately [redacted] of the increase is associated with an increase in the delivered cost of Black Butte coal to the Jim Bridger plant, which has increased from [redacted] in the prior case to [redacted] in the current case, an increase of [redacted]. This increase is related to escalation of contract-specific producer and consumer price indices under both the coal supply and rail agreements.

The remaining [redacted] increase is associated with higher Bridger Coal Company costs. Bridger Coal Company costs have increased slightly from [redacted], an increase of [redacted] per ton. The increase is largely due to an increase in depreciation and final reclamation expense offset by a reduction in labor and outside service costs.

Q. Please explain the increase in the Colstrip plant coal costs.

A. Colstrip plant coal costs have increased from [redacted] in the prior case to [redacted] in the current case, an increase of [redacted]. Colstrip coal costs are per the approved Annual Operating Plan prepared by Westmoreland and approved by the Colstrip plant owners. The increase relates to higher mine variable costs.

Decreases in Retail Load

Q. What is the magnitude of the change in retail loads and how does it impact the Company's NPC?

A. This filing uses pro forma load for calendar year 2014 to determine NPC (before applying the production factor adjustment). The 2011 Rate Case used pro forma load for the 12 months ending May 2013. The pro forma WCA load in this case is approximately 0.5 million MWh, or 2.5 percent, lower than the pro forma load for the 2011 Rate Case. The reduction in load impacts most major categories of NPC, including wholesale market purchases and sales, as well as generation from the Company's coal and natural gas fired resources. The overall dollar impact is a reduction to Washington NPC of approximately $3.6 million. Ms. Kelcey A. Brown provides additional testimony supporting the pro forma load used in this case.

Decreases in Electricity and Natural Gas Swaps

Q. Please explain the reduction in electricity and natural gas swap costs.

A. The Company uses electricity and natural gas swaps to reduce its exposure to price risk on the wholesale market. The Company's use of these instruments is governed by its Risk Management Policy. In a general rate case, the NPC includes the expected gain or loss on settlement for transactions that exist at the time the case is prepared. The net Washington expense related to electricity and natural gas swaps is approximately $5.5 million lower than the 2011 Rate Case, mainly attributable to reduced expenses for natural gas swaps. In this case, the impact on Washington NPC of natural gas swaps is approximately $2.8 million, down from $8.6 million in the 2011 Rate Case, a reduction of $5.8 million. The lower costs are due to a lower volume of swap transactions for calendar year 2014 compared to the previous rate case and a smaller difference between the average fixed price of the swap transactions and market price.

CHANGES TO NPC MODELING SINCE THE 2011 RATE CASE

Q. What changes has the Company made to the way it models NPC since the 2011 Rate Case?

A. Pro forma NPC in the current filing include the following modeling assumptions:

- The Company modeled the Leaning Juniper and Goodnoe Hills wind projects and the Chehalis plant in PACW.
- The Company adjusted the monthly capacity factor for wind generation to match the average 48-month history of wind generation output.
- Hydro generation is modeled on a weekly rather than hourly basis, and forced outages are reflected as a percentage reduction to available capacity at hydro units with storage capability.
- The Company included its rights to the DC Intertie transmission line and its access to the NOB market hub in the GRID topology.
- The Company included the cost of holding reserves to integrate non-owned wind facilities located in the PACW, and proposes to credit to customers related revenue from the Company's transmission rate case at the Federal Energy Regulatory Commission (FERC) through the proposed PCAM.

Inclusion of the Leaning Juniper and Goodnoe Hills Wind Projects and the Chehalis Plant in PACW

Q. What is the impact of including the Leaning Juniper, Goodnoe Hills, and Chehalis plants in PACW?

A. Since each of these plants was procured by the Company, they have been electrically connected to BPA's balancing authority area. Starting in 2013, the

Company will have the necessary capital upgrades and contractual arrangements with BPA to enable the Company to operate each plant within PACW. For the wind plants, this change avoids expenses previously paid to BPA for wind integration and avoids potential curtailment by BPA under Dispatch Standing Order (DSO) 216 and Oversupply Management Protocol (OMP). For Chehalis, this change allows PacifiCorp to avoid certain transmission-related expenses and utilize the plant to provide reserve capacity.

Adjustment of the Monthly Capacity Factor for Wind Generation to Match the Average 48-Month History of Wind Generation Output

Q. Please explain how the Company used historical wind output to calculate the wind generation in this case.

A. In this case, the Company is using historical monthly wind capacity factors, where available, to project the normalized wind generation for calendar year 2014. In past cases, wind generation was included in GRID based on a "P50" forecast. A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast. The Company used this approach because it did not have enough historical data upon which to base a forecasted level of wind generation.

For many of the Company's owned plants and power purchase agreements (PPAs), the Company now has enough data to use average actual output to calculate normalized generation levels. Where possible, the Company used the 48-month average historical generation at each wind facility in the PACW to determine the generation level. If 48 months of historical data was not available, the Company used the P50 forecast to fill in missing data. The Company produced the generation profile by applying the ratio of actual and forecast capacity factors to the generation profile of the P50 forecast.

Q. Did the Company make any adjustments to the historical data for Leaning Juniper and Goodnoe Hills?

A. Yes. To date, the Leaning Juniper and Goodnoe Hills wind projects have been operated in BPA's balancing authority area and subject to curtailment by BPA under DSO 216 and OMP. Moving these two plants into PACW means they will no longer be subject to DSO 216 and OMP curtailments. To compute the 48-month history for these plants, the Company removed curtailment events.

Q. What is the impact of using the adjusted historical generation rather than the P50 forecast?

A. For Company-owned facilities, wind generation is approximately 12 percent lower than the 2011 Rate Case, which increases Washington NPC by approximately $1.0 million.

Changes to the Modeling of Hydro Generation

Q. Please explain why the Company input hydro generation into GRID on a weekly basis rather than hourly.

A. In the 2010 Rate Case, the Company used an hourly hydro generation forecast that was shaped by the Vista model based on market price. This method optimized the value of hydro energy, but did not account for the value of hydro reserve capability. In this case, the Vista model continues to determine the optimal weekly hydro generation based on market price. This captures the value of the Company's hydro storage capability. The GRID model then shapes the generation within higher priced periods of each week while holding some capacity available for reserves. These reserves would otherwise be assigned to thermal resources, such as the Jim Bridger plant, reducing economic generation and increasing market purchases. By accounting for the value of reserves in hydro dispatch, costs are reduced and the resulting generation patterns better match the Company's actual operations where hydro reserves are maintained throughout the day to balance rapid changes in load and wind. Over the last several years, several of the Company's Mid-Columbia hydro contracts have expired, thus increasing the importance of the Company's remaining hydro reserve capability.

Q. Are forced outages at hydro facilities reflected in the resulting hydro generation?

A. Yes. Similar to the method used for thermal plants, the Company has reflected a normalized level of forced outages on hydro units with storage capability[4] as a flat percentage reduction to the available capacity across all hours of the pro forma period. The reduction to plant capacity is based on a 48-month history of forced outages by plant. In addition, an adjustment to reflect energy lost due to forced outages is made to hydro generation based on historical measurements beginning in January 2011.

[4] Output from run of river hydro facilities is included based on historical generation, including the impact of outages.

Inclusion of the Rights to the DC Intertie Transmission Line

Q. Please describe the Company's transmission rights related to the DC Intertie.

A. The DC Intertie contract was executed 18 years ago on May 26, 1994, to provide delivery of up to 200 MW 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 PACW. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222 MW of power into the PACW. The agreement provided that if the Company procured additional transmission rights by June 1, 1994, then it could import the remaining 200 MW to its system. The Company secured the remaining 200 MW of transmission rights by acquiring 200 MW of transmission capacity on the DC Intertie to the Buckley substation. The Company terminated the WPSA effective January 1, 2002, but the DC Intertie contract remained effective by its terms.

The DC Intertie 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 serve PacifiCorp's retail loads. Loads in California are relatively low in the winter when loads in the PACW and the rest of the Pacific Northwest are at their highest.

Q. Did the Commission address the DC Intertie costs in a previous case?

A. Yes. In the 2010 Rate Case, the Commission adopted an adjustment to remove the cost of the DC Intertie contract on the basis that it was not used and useful in that case. The premise of the adjustment was that there was no evidence that the DC Intertie capacity was used because the Company had not included NOB transactions in the GRID model.

Q. Does GRID now include transactions at the NOB wholesale market?

A. Yes. The Company has updated the GRID topology to include the DC Intertie capacity and a NOB market hub, allowing GRID to make purchases at NOB to serve PACW load. These purchases are included in NPC in this case.

Q. Does the Company rely on the DC Intertie to operate the PACW?

A. Yes. The Company relies on the DC Intertie for reliability purposes. Similar to the expired BPA peaking contract where the Company had the ability to increase its power deliveries next hour, the DC Intertie enhances reliability by giving the Company firm access to a functioning market. It also allows additional delivery of power to serve customers in the Company's central Oregon load pocket.

Q. Does the Company expect to continue to rely on the DC Intertie capacity in the future?

A. Yes. The 2011 IRP Update, filed in March 2012, includes reliance on market purchases at NOB via the DC Intertie.

Inclusion of the Cost of Holding Reserves to Integrate Non-Owned Wind Facilities Located in the West Control Area

Q. Has the Company included the cost of integrating non-owned wind facilities located in the PACW?

A. Yes. The Company is required to provide services necessary to integrate wind resources delivered by wholesale customers under federal law and as a function of being a balancing authority area. Customers benefit from the Company being a balancing authority area and the revenues associated with wheeling for wholesale customers collected through the Open Access Transmission Tariff (OATT). Customers also benefit by having access to Company-owned transmission for network and point-to-point service, which are necessary to serve load and transact in wholesale markets.

Q. Did the Commission address this issue in the 2010 Rate Case?

A. Yes. In the 2010 Rate Case, the Commission adopted an adjustment to remove the cost of intra-hour wind integration for non-owned facilities on the basis that the costs were not known and measurable. In addition, it reasoned that the Company's OATT did not include a rate for wholesale wind integration and that the Company should file with the FERC for an amendment to its OATT.

Q. Has the Company provided additional support demonstrating the known and measurable nature of these costs?

A. Yes. The Company is in the process of completing its second, comprehensive wind integration study to quantify the impact of integrating owned and non-owned wind on PacifiCorp's system. I discuss details of the most recent study later in my testimony and have provided a copy as Exhibit No.___(GND-3).

Q. Has the Company also filed with FERC for an amendment to its OATT?

A. Yes. The Company filed a rate case with FERC on May 26, 2011, which included updated charges for ancillary services needed to integrate wind, including a new Schedule 3A governing generator regulation and frequency response service. FERC accepted the filing, suspended the filing for five months, and allowed the new rates to become effective subject to refund at the conclusion of the suspension period. This case is currently in the settlement phase.

Q. How does the Company propose to treat revenue received under Schedule 3A?

A. The Company proposes to include revenue received under Schedule 3A as an offset to NPC deferred under its proposed PCAM, starting with the effective date of new rates from this case and until base rates are again reset including revenue from Schedule 3A. In this manner, customers will receive credit for revenue received to cover the cost of providing third-party wind integration services.

Q. Does this case already include some revenue to cover the cost of wind integration in addition to any revenue that might be received from the new Schedule 3A?

A. Yes. The Company has several commercial contracts in place for storage and integration of generation from non-owned wind facilities, and the related revenue is included as a revenue credit in FERC Account 456, Other Electric Revenue. For example, the PACW includes a contract with Seattle City Light related to output from the Stateline project, and approximately $2.2 million of revenue on a Washington basis is included in this case.

Compliance with Commission-Ordered Adjustments

Q. Please describe how the Company reflected previous Commission-ordered adjustments, other than those already discussed, in the current filing.

A. The NPC for the pro forma period in the current filing have incorporated the following adjustments ordered by the Commission in the 2010 Rate Case:

- De-optimized energy delivery of the sales contract with the Sacramento Municipal Utility District (SMUD) based on monthly delivery patterns of the four-year historical average;
- Imputed outage rate of Colstrip Unit 4 at 8.0 percent;
- Prorated wheeling expenses for Colstrip Unit 4 based on the transmission capacity from Colstrip to the PACW, instead of splitting equally between PACW and PACE;
- Included margin on arbitrage transactions based on the four-year historical average;
- Excluded non-firm transmission capability and expenses; and
- Adjusted heat rates and minimum generation levels of the thermal plants for outage derates.

2012 WIND INTEGRATION STUDY

Q. How has the Company modeled the cost of integrating wind resources in the PACW?

A. Integration costs are modeled for both inter-hour and intra-hour integration of wind resources in the PACW. Intra-hour integration costs result from the Company holding reserves on its facilities to compensate for the minute-to-minute variation in wind output from facilities owned by the Company or from which the Company purchases the output, as well as third-party wind resources located within the PACW. In addition, a fixed charge per MWh is included for the inter-hour, or system balancing, costs and is applied to all Company-owned and purchased wind generation.

Q. Did the Company base its wind integration costs on the draft 2012 Wind Integration Resource Study (2012 Wind Study)?

A. Yes. The latest version of the 2012 Wind Study, published on November 15, 2012,[5] is the result of an extensive public process that received guidance from a Technical Review Committee that included numerous subject-matter experts. I have attached a copy of the 2012 Wind Study to my testimony as Exhibit No.___(GND-3). The Company believes that the level of reserves required to integrate wind generation net of system load, as identified in the 2012 Wind Study, is appropriate.

Q. Did the Company adjust the modeled reserve requirement to account for new wind resources?

A. Yes. The reserve requirement included in the current case accounts for integrating all additional wind capacity that will be online during the test period, including the Leaning Juniper and Goodnoe Hills plants that will be transferred to PACW.

Q. What are the Company's wind integration costs included in NPC?

A. The costs of integrating wind generation in the PACW included in NPC are approximately $3.13 per MWh.

[5] *See* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/2012WIS/2013IRP_2012WindIntegration-DRAFTReport-11-15-12.pdf.

PACIFICORP'S WASHINGTON PCAM PROPOSAL

Overview

Q. Please briefly describe the Company's proposed PCAM.

A. The proposed PCAM is a rate mechanism designed to allow the Company to collect or credit the differences between the actual NPC incurred to serve Washington customers and the amount of NPC collected from Washington customers through rates.

On a monthly basis, the Company will compare the actual system net power costs (Actual NPC) to the net power costs embedded in rates (Base NPC), and defer the differences in a balancing account with interest. After a positive or negative balance of $5 million in Washington NPC has accrued in the balancing account, a PCAM rate will be calculated to collect from or credit to customers the accumulated balance over the subsequent year. The Company proposes to implement the PCAM beginning with its 2014 Actual NPC. The Company also requests authority to file for a one-time update to Base NPC if it has not filed a general rate case within 24 months of its last general rate case filing. This protects customers from large accruals in the PCAM balancing account between general rate cases.

Q. Does the Company's proposed PCAM include deadbands or sharing bands?

A. No. The Company proposes a PCAM with a dollar-for-dollar true-up to actual costs, allowing customers to receive full credit for any over-recovery of NPC in rates and allowing the Company to receive the full amount of under-recovery of NPC in rates.

Q. What types of costs would be included in the PCAM?

A. The PCAM will be calculated using all components of NPC as traditionally defined in the Company's general rate cases and modeled by the Company's GRID model. Specifically, Base NPC and Actual NPC will include amounts typically booked to the following FERC accounts:

Account 447—Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID

Account 501—Fuel, steam generation; excluding fuel handling, start up fuel/gas,[6] diesel fuel, residual disposal, and other costs that are not modeled in GRID

Account 503—Steam from other sources

Account 547—Fuel, other generation

Account 555—Purchased power, excluding BPA residential exchange credit pass-through if applicable

Account 565—Transmission of electricity by others

Q. Will the PCAM include recovery of fixed costs related to power supply (i.e., capital investment in rate base)?

A. No. The PCAM will address net power cost expenses only and will not include any recovery of capital investment. For fixed cost recovery, PacifiCorp will rely upon the provision in Washington's Greenhouse Gas Emissions Performance Standard (EPS)[7] that allows deferral of costs for later inclusion in rates in a

[6] Start up fuel is accounted for separate from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.
[7] The Greenhouse Gas Emissions Performance Standard is codified at RCW 80.80.

general rate case.[8] The provision covers costs of qualifying long-term commitments to base load electric generation and eligible renewable resources under Washington's renewable portfolio standard (RPS), the Energy Independence Act (EIA).[9]

Q. Do Actual NPC include adjustments before the comparison with the Commission approved Base NPC?

A. Yes. Adjustments will be made to Actual NPC as booked to be consistent with the Company's production dispatch model, to remove prior period accounting entries, and to include applicable Commission-adopted adjustments reflected in the Company's most recent general rate case filing. Actual NPC will not be adjusted for variations in customer loads, wind generation, hydro conditions, or forced outages because these give rise to the fluctuations in NPC that this mechanism is designed to capture. Actual NPC will be subject to review by the Commission and other parties in the proceeding to set the PCAM rate.

---

[8] RCW 80.80.060(6). This subsection provides:

> An electric company may account for and defer for later consideration by the commission costs incurred in connection with a long-term financial commitment, including operating and maintenance costs, depreciation, taxes, and cost of invested capital. The deferral begins with the date the power plant begins commercial operation or the effective date of the power purchase agreement and continues for a period not to exceed twenty-four months; provided that if during such period the company files a general rate case or other proceeding for the recovery of such costs, deferral ends on the effective date of the final decision by the commission in such proceeding. Creation of such a deferral account does not by itself determine the actual costs of the long-term financial commitment, whether recovery of any or all costs is appropriate, or other issues to be decided by the commission in a general rate case or other proceeding for recovery of these costs. For the purpose of this subsection (6) only, the term "long-term financial commitment" also includes an electric company's ownership or power purchase agreement with a term of five or more years associated with an eligible renewable resource as defined in RCW 19.285.030.

[9] The EIA is codified at RCW 19.285.

Q. Please explain the balancing account and the calculation of the PCAM rate.

A. The balancing account and PCAM rate serve as a true-up mechanism to recover or credit the differences between Base NPC and Actual NPC. On a monthly basis, the Company will compare Actual NPC to Base NPC. Any differences in the system per-unit cost will be multiplied by actual Washington MWh load in that month and the product will be deferred in the balancing account. The monthly under- or over-recovery will accumulate in the balancing account.

After a positive or negative balance of $5 million in Washington NPC has accrued in the PCAM balancing account, the cumulative deferred balance in the balancing account will be converted to a Schedule 94 deferred PCAM rate, as discussed in the testimony of Ms. Joelle R. Steward.

Q. When will the Company reconcile the PCAM costs and recoveries?

A. The Company proposes to file to set the deferred PCAM rate within 60 days after the amount in the balancing account triggers a filing, but no more often than once per year. The Company proposes that the deferred PCAM rate go into effect 60 days after the filing.

Need for the Proposed Washington PCAM

Q. Why does the Company need a PCAM in Washington?

A. As a result of the Commission's reliance on the WCA, the Company's NPC represent a larger part of the Company's total revenue requirement. The Company's NPC is subject to a high degree of variability driven by factors largely outside of the Company's control. Given these factors, a PCAM is an accurate and appropriate ratemaking model for Washington NPC.

Q. Did the Commission previously conclude that PacifiCorp's Washington NPC was sufficiently variable to justify implementation of a PCAM?

A. Yes. In response to the Company's last PCAM filing in the 2006 Rate Case, the Commission concluded that the amount of potential variability in PacifiCorp's NPC was "sufficient to warrant consideration of a PCAM as a means to accommodate this variability in ratemaking."[10] This conclusion was based on analysis from the Company and from Staff on the variability of hydro-generation, wholesale power prices, and fuel prices over which the Company has no, or limited, control.[11]

Q. Does the history of the Company's actual NPC recovery in Washington since 2007 demonstrate continuing NPC variability?

A. Yes. Table 1 below (also provided as Exhibit No.___(GND-4)) shows that, since 2007, the Company has under-recovered a total of $54.6 million in Washington NPC.

Table 1

PacifiCorp
NPC in Rates vs. Actual (000's)

	2007	2008	2009	2010	2011	Cumulative Total
In Rates	$91,233	$92,542	$95,704	$109,062	$115,956	
Actual NPC	$106,817	$111,496	$107,667	$110,475	$122,680	
Difference from In Rates*	$15,584	$18,954	$11,963	$1,413	$6,724	$54,638
		2008 GRC	2009 GRC	2010 GRC	2011 GRC	
		UE 080220	UE 090205	UE 100749	UE 111190	
Historic Test Period		12 ME Jun. 2007	12 ME Jun. 2008	12 ME Dec. 2009	12 ME Dec. 2010	
NPC Forecast Period		FYE Jun. 2008	FYE Dec. 2010	FYE Mar. 2012	FYE May 2013	

*Difference from in rates is calculated based on the $/MWh difference between in-rates and actual NPC times the actual load

[10] 2006 Rate Case, Order 08, ¶71.
[11] *Id.* at ¶68.

Q. Has the variability of PacifiCorp's NPC increased since the Company's 2006 Rate Case?

A. Yes. The EIA was enacted in November 2006, shortly before the decision in the Company's 2006 Rate Case, and the EPS was enacted in 2007. As discussed below, in compliance with the EIA and the EPS, the Company has added wind and natural gas facilities to its PACW generation portfolio, which have increased NPC variability and risk. On a combined basis, wind and hydro generation now comprise approximately 36 percent of the Company's installed generation capacity in the PACW. On average, wind and hydro generation now serve 32 percent of PACW load, fluctuating between six percent and 86 percent of PACW load. Since passage of the EPS, the Company's natural gas generation capacity in the PACW has more than doubled with the addition of the 512 MW Chehalis plant.

General Policies Supporting PacifiCorp's PCAM

Q. In response to the Company's PCAM proposal in the 2005 Rate Case, the Commission stated that a "90/10 sharing band and the absence of a deadband do not adequately balance risk and benefits between shareholders and ratepayers."[12] In light of this statement, why is the Company proposing a PCAM without deadbands or sharing bands?

A. Fundamentally, the Company believes that PCAM deadbands and sharing bands are poor regulatory policy. While the Commission has previously observed that deadbands and sharing bands can motivate a utility to effectively manage or

[12] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Dockets UE-050684, Order 04, ¶ 99 (April 17, 2006) (2005 Rate Case).

reduce NPC,[13] this justification fails under careful review. It is now clear that the most significant contributors to NPC variability (e.g., stream flows, wind, market prices, fuel prices, loads, forced outages) are not subject to utility management control. This fact is immutable, irrespective of the degree of utility management motivation. Deadbands and sharing bands do not work as intended and instead produce random windfalls or losses to the utility and its customers, undermining predictable and fair utility rates and regulation.

Q. Has the Commission required deadbands and sharing in all energy cost recovery mechanisms for other Washington utilities?

A. No. The Commission did not require deadbands or sharing in allowing a hydro-generation deferral for PacifiCorp in the past.[14] Also, I understand that the Commission has included deadbands and sharing in cost recovery mechanisms for electric supply costs, but not for natural gas supply costs. This distinction demonstrates the Commission's view that the design of such mechanisms "must take into account the specific circumstances facing the utility," and that they "need not be the same."[15] The policy that justifies a dollar-for-dollar true-up of natural gas supply costs—that natural gas companies have little or no ability to control or manage these costs—supports PacifiCorp's proposed PCAM, especially in light of Washington's RPS and EPS, discussed below.

Q. Have a majority of state commissions rejected the use of deadbands and sharing bands in the design of energy cost recovery mechanisms?

A. Yes, to my knowledge. I reviewed the PCAMs of other utilities, including those

---

[13] *Id*. at ¶96.
[14] *Id.* at ¶308; *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-080220, Order 05 (Oct. 8, 2008).
[15] *Id.* at ¶ 91.

in the comparable group of companies Dr. Hadaway uses for determining the Company's cost of equity. The majority of utility PCAMs that I reviewed do not contain deadbands or sharing mechanisms. For more detail on the PCAMs I reviewed, please refer to Exhibit No.___(GND-5).

Q. Does the Company already have a PCAM in another state that is similar to the structure of the PCAM proposed in this filing?

A. Yes. Since 2008, the Company has had a dollar-for-dollar true-up mechanism for variances in NPC in California called an Energy Cost Adjustment Clause (ECAC). Like Washington, California has an RPS and an EPS. In three other states, Idaho, Wyoming and Utah, the Company has mechanisms with sharing bands (90/10 in Idaho and 70/30 in Wyoming and Utah), but no deadbands.

The Public Utility Commission of Oregon just adopted a PCAM for PacifiCorp which, over the Company's objection, includes deadbands and sharing bands.[16] In this decision, the Oregon commission defaulted to its past PCAM design, without fully considering the increased NPC-related risk the Company now faces. The PCAM adopted by the Oregon commission is an outlier compared to PacifiCorp's other approved PCAMs and the PCAMs of other utilities in PacifiCorp's comparable group.

Q. Will the Company have less of an incentive to minimize actual NPC if its proposed PCAM is adopted?

A. No. The Company will continue to be subject to prudence reviews in Washington and its five other states. Implementing a PCAM in Washington will not change

---

[16] *In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision*, Docket No. UE 246, Order No.12-493 (December 20, 2012).

the incentive the Company has to act prudently and minimize actual NPC.

Q. Does the PCAM shift all of the risk of increases or decreases in NPC completely away from the Company and onto the customers?

A. No. The proposed PCAM will recover from customers only actual NPC and will pass through to customers any actual NPC reductions. While this creates symmetry, a desirable feature of an adjustment mechanism, it does not shift from the Company to customers the risks of prudently managing its system. The Company retains that risk. The Commission, Staff, and parties will have the opportunity to assess the prudence and reasonableness of actual NPC in the Company's PCAM rate filings.

Q. How would Washington customers benefit from PacifiCorp's proposed PCAM?

A. Customers will benefit from the Company's proposed PCAM in several ways:

- The PCAM will result in rates for customers that more closely reflect the actual power supply costs to serve them.
- In high wind or water years, customers will realize the full benefit of actual wind and hydro generation on the Company's system. When actual NPC is lower than NPC in rates, rates will be adjusted to reflect lower actual costs.
- As explained in the testimony of Mr. Bruce N. Williams, the PCAM will stabilize the Company's earnings and cash flows and reduce its imputed debt, all of which should improve the Company's ability to finance its on-going capital investments.

- The PCAM should produce a more streamlined regulatory process focusing on the prudence of the Company's NPC, rather than modeling issues, as has been the case in prior general rate cases.

PacifiCorp's Increased NPC Business Risk Supports PacifiCorp's PCAM

Q. Since the Company's prior PCAM proposals in the 2005 and 2006 rate cases, have circumstances changed materially with respect to the Company's NPC business risk?

A. Yes. The passage of the EIA in 2006 and the EPS in 2007 warrant reassessment of PCAM design. These statutes remove a significant part of the Company's discretion with respect to power supply to serve Washington customers, mandating reliance on renewable and natural gas generation resources. This mandate has further reduced the Company's ability to manage NPC variability and increased the Company's NPC business risk. At the same time, these statutes require customers to bear the costs of prudent compliance with the mandates on electric generation resource mix, shifting the balance of risks from utilities to customers.

In addition, the Commission's adoption of the WCA in the 2006 Rate Case increased the Company's NPC risk by making NPC a larger portion of the Company's revenue requirement and increasing the Company's reliance on market purchases and variable resources for its power supply.

Q. Please provide the cost-recovery language to which you refer.

A. Under RCW 19.285.050(2) of the EIA:

> An investor-owned utility is entitled to recover all prudently incurred costs associated with compliance with this chapter. The

> commission shall address cost recovery issues of qualifying utilities that are investor-owned utilities that serve both in Washington and in other states in complying with this chapter.

The deferral provisions of RCW 80.80.060(6) of the EPS, designed to allow a utility to recover capital costs without shortfalls caused by the timing difference between when costs are incurred and when costs are included in rates, were described earlier.

Q. Please describe the major changes to the Company's PACW generation portfolio since 2006.

A. Since 2006, the Company has added approximately 405 MW of new wind resources (Leaning Juniper, Goodnoe Hills, Marengo I and Marengo II) and 74 MW of wind PPAs in PACW. In total, the Company now has 521 MW of owned and contracted wind resources used to serve load in PACW and forecasts approximately 561 MW for the 2014 pro forma period.

Before 2006, PACW had one large natural gas generation resource: the 484 MW Hermiston plant (50 percent owned, 50 percent purchased). In 2008, the Company acquired the 512 MW Chehalis natural gas plant.

Q. Is the Company now recovering all of its NPC-related costs of compliance with the EIA?

A. No. Without a PCAM in place, the Company is subject to the risk of significant NPC under-recovery. In the past five years since enactment of the EIA, the Company's Washington NPC recovery shortfall exceeded $50 million. The Company's renewable resources and new gas facilities have contributed to this under-recovery by increasing the complexity and variability of normal system operations and the challenges of accurately forecasting NPC. For example, in PACW, the Company's wind resources have an average capacity factor of 29 percent, with capacity swinging from a minimum of zero to a maximum of 93 percent depending on weather conditions. When the Company under-recovers its NPC, this under-recovery includes EIA compliance costs such as wind PPAs and the costs of shaping, firming, and integrating wind resources.

Q. How has the Company reevaluated and changed its operational practices to address the increase in intermittent renewable resources in its portfolio?

A. The Company has the obligation to balance load and resources within every hour to maintain reliable service to customers. Because generation from intermittent resources is inherently unpredictable even one hour ahead, the Company must set aside additional balancing reserves every hour to ensure that it has adequate capacity. These volumes vary every hour and are therefore subject to prices that also vary every hour depending upon market supply and demand. As I discussed earlier in my testimony, I have provided the Company's most recent wind integration study as Exhibit No. ___(GND-3) to my testimony.

Q. Did FERC recently recognize that variable energy resources (VERs) such as wind are causing major changes in power delivery systems?

A. Yes. In FERC Order No. 764 in Docket No. RM 10-11-000, issued June 22, 2012, FERC stated:

> VERs are making up an increasing percentage of new generating capacity being brought on-line. This evolution in the Nation's generation fleet has caused the industry to reevaluate practices developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation.

Q. Beyond system balancing issues, do intermittent renewable resources cause other impacts to the Company's operations?

A. Yes. The Company's wind resources, as well as those owned by other market participants, are concentrated in high wind resource areas such as the Columbia River Gorge. As the weather changes, this concentration results in large swings of unexpected increases or reductions in energy supply that can range from zero to full nameplate capacity. Incremental supply reduces market prices, and reductions in supply increase market prices. When there were only a handful of intermittent renewable resources this was not a material issue. Now, with thousands of megawatts of installed renewable resources, the impact on market prices is substantial.

Q. Do changes in market prices due to intermittent renewable resources impact the Company's NPC?

A. Yes. Historically, the Company has been able to reduce NPC for its customers by making wholesale sales of excess generation from its owned and contracted resources. In circumstances where market prices and associated margins fall because of incremental wind supply, the Company's ability to make such beneficial sales is limited. At times, market prices now go so low that the Company's thermal generation is reduced to minimum loads or even shut down.

Q. Are there other related aspects of the Company's operations that have changed since 2007 that increase the likelihood of NPC variances from forecasted levels?

A. Yes. In addition to the dramatic increase in intermittent renewables, the

Company's resource portfolio has shifted to a less predictable generation profile due to increased reliance on flexible natural gas generation that is used to back up intermittent renewable generation, maintain reliable supply to customers, and comply with the EPS. The effect of increased demand for flexible resources that result from intermittent generation, combined with the recent expiration of a significant amount of flexible capacity such as the BPA Peaking contract, make it necessary for the Company's natural gas generation to integrate, firm, and shape wind generation. Apart from demand-side resource acquisition over the last several years, the Company's new generation acquisitions have been comprised of roughly 50/50 VER resources and natural gas resources.

Q. How is the variability of wind generation different than the variability created by changes in hydroelectric generation or loads?

A. Wind is intermittent and has little to no predictable pattern of delivery. It can start and stop quickly, and must be firmed, shaped, and integrated by the Company's dispatchable resources on a moment-to-moment basis. The addition of wind has dramatically changed the way the Company operates its system. Load, hydroelectric generation, and thermal generation all have some form of unpredictability, but they are not intermittent. Loads are predictable in that they increase in the morning and decrease at night, and hydroelectric resources will produce more electricity when there is greater rainfall and during the spring runoff. Wind has little to no predictable pattern of delivery, and therefore its intermittency creates a much more complex operating environment for the Company as compared to the variability of hydroelectric resources and loads.

Adding a significant amount of intermittent resources to the Company's system in accordance with the EIA lessens the Company's ability to produce reliable pro forma NPC.

Q. How does the Company model wind in its pro forma NPC?

A. Using the GRID model, the Company models the generation of its wind facilities in four-hour blocks uniformly over the pro forma period. The Company models wind in a flattened, normalized manner because there is no way to more reliably forecast the real-time volatility of wind generation.

Q. Does the Company's GRID model capture the variability and uncertainty of wind generation in the cost of reserves modeled for wind integration?

A. No. GRID models wind integration costs on a normalized basis. The reserves modeled in GRID are based on historical variability, but GRID assumes the reserve volume is the same for all hours in a given month and further assumes no market price volatility. Because wind volatility and market prices vary every hour of the year, it is certain that actual reserve costs will vary from the GRID forecast. Normalized modeling of the Company's wind integration cannot capture the multi-dimensional cost impacts associated with integrating large amounts of wind resources.

Q. In its current wind integration cost modeling, does the Company consider the costs associated with ramping down a unit in its modeling of reserves for wind in the GRID model?

A. No. The Company models only the up reserves, or those reserves that are required to balance the system if the wind does not generate as compared to forecast or declines rapidly within the hour.

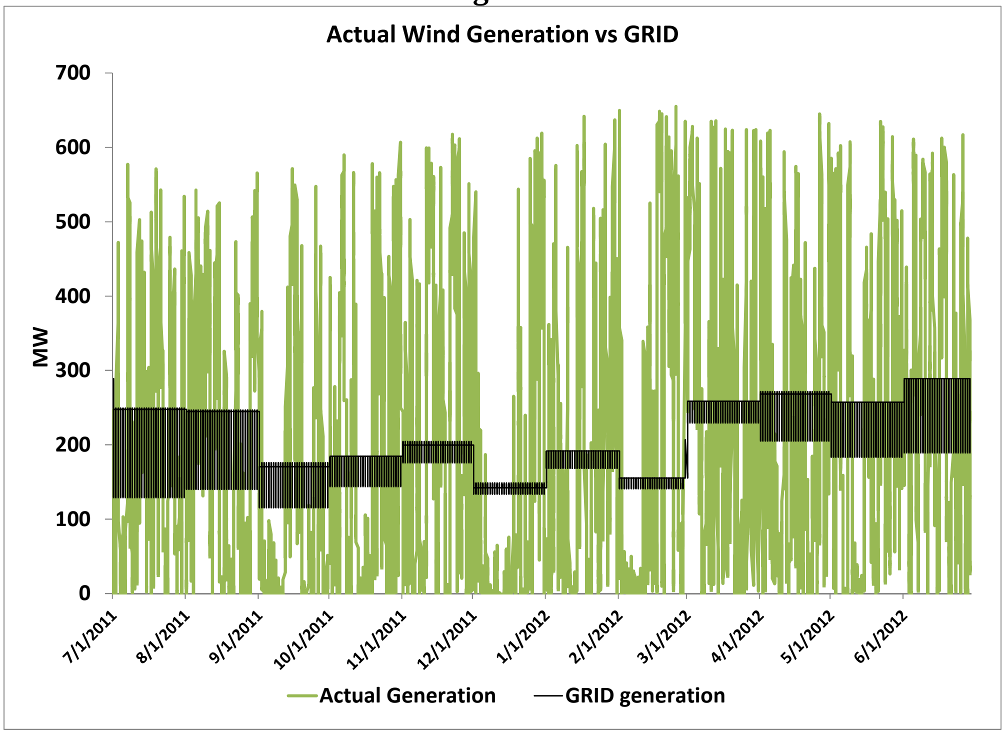
Q. Will the actual cost of holding reserves for intra-hour wind variations differ from what the Company models within GRID?

A. Yes. The Company includes an average level of reserves in GRID that are held in each hour to take into consideration the different level of reserves that are required on a real-time basis for regulating and following wind facilities. By normalizing the additional intra-hour reserves across every hour of the year, there is the potential to under- or over-forecast the costs associated with holding these reserves on a real-time basis.

Q. How does the Company's normalized forecast of wind generation compare to actual wind output in PACW?

A. Figure 1 below contrasts the constant fluctuations of actual wind generation during the 12 months ended June 2012 to the normalized wind generation used in GRID in this case.

Figure 1



Q. To quantify one aspect of the Company's increased NPC-related risks, has the Company measured the variance between actual and forecast wind generation levels in its Washington NPC since enactment of the EIA?

A. Yes. PacifiCorp measured the change in the net market value of its owned wind generation from 2007 to 2011, measured using actual and forecast wind generation levels and market prices. As shown in Table 2 below, the combined impact of variances in wind generation and market prices over the historical period ranges from $1.5 million to $36.6 million of over-forecast value on a PACW basis, or a five-year average of $21.1 million. The variance in wind generation at Company-owned facilities also impacts the level of production tax credit realized, and over the same five-year period the Company would have over-credited customers approximately $2.0 million on average on a PACW basis.

Because the Company's wind penetration must increase under the EIA, the NPC recovery risk associated with variances between forecast and actual wind generation is also expected to increase.

Table 2
Net Market Value of Wind Generation ($m)

	2007	2008	2009	2010	2011	Average 5-Year
WA GRC	11.1	16.5	36.4	68.9	52.7	37.1
Actual	7.0	14.9	18.1	24.0	16.1	16.0
Forecast Variance	(4.1)	(1.5)	(18.3)	(44.9)	(36.6)	(21.1)

Symmetrical Treatment of NPC-Related Costs and Revenues Supports PacifiCorp's PCAM

Q. Did the Commission recently address ratemaking treatment for revenues from the sale of PacifiCorp's renewable energy attributes (REAs) and renewable energy credits (RECs) in the 2010 Rate Case?

A. Yes. In Order 06 in that docket, the Commission ordered PacifiCorp to create a balancing account to track REA and REC revenues and provide customers a dollar-for-dollar rate credit.[17]

Q. How does the EIA define RECs?

A. A Washington REC is defined as:

> [A] tradable certificate of proof of at least one megawatt-hour of an eligible renewable resource where the generation facility is not powered by freshwater. The certificate includes all of the nonpower attributes associated with that one megawatt-hour of electricity, and the certificate is verified by a renewable energy credit tracking system selected by the department.[18]

A "nonpower attribute" means:

[17] 2010 Rate Case, Order 06, ¶¶ 244-246.
[18] RCW 19.282.030(19).

> [A]ll environmentally related characteristics, exclusive of energy, capacity reliability, and other renewable resource, including but not limited to the facility's fuel type, geographic location, vintage, qualification as an eligible renewable resource, and avoided emissions of pollutants to the air, soil, or water, and avoided emissions of carbon dioxide and other greenhouse gases.

Q. Does the Company's PCAM propose to treat NPC expense (the power attributes of electricity) the same as REA and REC revenues (the non-power attributes of electricity) under Order 06?

A. Yes. REAs and RECs are created by the production of electricity and are therefore inextricably linked with the electricity generated by renewable resources. The Company's PCAM recognizes this fact by proposing the same dollar-for-dollar treatment for the costs of electricity production (i.e., the Company's NPC) as that now in place for REA and REC revenues. While the Company has filed for judicial review of Orders 10 and 11 in the 2010 Rate Case addressing retroactive rate credits for historical REA and REC revenues, it has not challenged Order 06's dollar-for-dollar tracker for REA and REC revenues on a prospective basis. Instead, PacifiCorp is now proposing a PCAM to provide symmetrical treatment of NPC and REA/REC revenues, properly matching the power and non-power attributes of the Company's renewable resources.

PacifiCorp Responses to Issues Raised in the 2006 Rate Case

Q. In the 2006 Rate Case, the Commission required the Company to address specific factors in any subsequent PCAM filing.[19] Please identify the factors relevant to this filing.

A. The Commission required the Company to address: (1) the process, accounting,

[19] 2006 Rate Case, Order 08, ¶ 111.

and reliability of "actual costs" used in the annual PCAM true-up; and (2) refinements to the PCAM design necessary to reflect asymmetry of power cost distribution.[20]

Q. Please provide some background on the issue related to accounting for actual NPC.

A. The Company's inter-jurisdictional allocation methodology was a key factor in the resolution of the Company's PCAM proposals in the 2005 and 2006 rate cases. In the 2005 Rate Case, the Commission rejected the Company's proposed allocation methodology, which precluded implementation of a PCAM.[21] In the 2006 Rate Case, the Commission approved the WCA, but rejected the manner in which the Company proposed to determine its actual NPC under that method. The Company proposed to calculate its actual NPC in part by modeling a re-dispatch of generation and transmission through the GRID model. The Commission expressed concern that the "computer-generated, pseudo-actual costs will themselves be only estimates."[22] To address this concern, the Commission indicated that it would require a more thorough and detailed explanation of how the proposed calculation of actual NPC accurately and reliably represents actual costs.

[20] The Commission also required a condition related to a PCORC filing that is inapplicable to this PCAM filing. In addition, it required the Company to address the relationship between historical water years used in NPC normalization and the PCAM in response to parties' arguments that, with a PCAM, the Company should filter historical water years. The Company now uses median hydro to normalize hydro generation, rendering this issue moot.
[21] 2005 Rate Case, Order 04, ¶¶ 98-99 (April 17, 2006).
[22] 2006 Rate Case, Order 08, ¶ 77.

Q. Has the Company changed its approach to calculating actual NPC in this filing?

A. Yes. The Company will not use "pseudo actual, computer-generated" data to calculate actual NPC. Instead, the Company will report actual NPC per the books and records of the Company for assets included in PACW. Assets or proportions of assets included in the reporting of actual NPC will be consistent with the WCA used to determine normalized NPC in the Company's general rate cases. To the extent an energy imbalance exists after accounting for actual loads and resources, the Company will account for the difference by reducing actual short-term balancing purchase or sales transactions, leaving actual, per books. I have provided five years of historical actual NPC for the years 2007 through 2011, compiled as I just described, in Exhibit No.___(GND-6).

Q. Can you specify how the Company's new accounting method for actual NPC differs from the method it used in the 2006 Rate Case?

A. In contrast to the method used since 2006, this new reporting will be based on the actual costs of the Company's resources in the PACW. In the 2006 Rate Case, the Company used the GRID model to balance the PACW after accounting for actual NPC information. To calculate the system balancing, however, GRID was allowed to alter the generation from the Company's dispatchable resources. The Company's approach in this case does not use the GRID model, eliminating the system re-dispatch issue.

Q. Do the proposed changes to the WCA described in the first section of your testimony facilitate the calculation of actual NPC for use in the PCAM?

A. Yes. The proposed changes to the WCA are designed to more accurately capture the Company's actual operations within PACW. These changes removed some of the impediments to the calculation of actual NPC on a per books basis under the WCA.

Q. Please provide background on the issue of asymmetrical NPC risk distribution and PCAM design.

A. In the 2006 Rate Case, the Commission reviewed the evidence of NPC variability submitted by Staff. This evidence analyzed the range of NPC between the Company's best and worst historical water years. The analysis showed a $26.6 million swing on a PACW basis, with $16 million of the differential, or 60 percent, on the side of higher costs (i.e., under-stated NPC).[23] Based upon this evidence, the Commission concluded that the distribution of PacifiCorp's NPC was skewed toward higher costs, in part because poor hydropower is correlated with higher wholesale costs and higher fuel costs.[24]

For a PCAM to maintain the proper balance of risks between the Company and its customers, the Commission concluded that a PCAM should have deadbands or sharing bands reflecting the asymmetrical NPC risk distribution.[25] The Commission indicated that an alternative would be to address the issue through an adjustment to the Company's rate of return.[26]

[23] *Id.* at ¶ 68.
[24] *Id.* at ¶ 85.
[25] *Id.* at ¶ 86.
[26] *Id.* at ¶ 87.

Q. Is the Company's hydro generation risk skewed toward higher costs (i.e., under-stated NPC)?

A. No, not according to the most recent and relevant data. Over the last ten years, PacifiCorp's PACW hydro-generation has ranged from 17 percent lower than the median to 22 percent higher than the median. The variation due to high and low hydro was $34 million on a PACW basis, of which approximately $19 million, or 55 percent, represents a reduction to NPC.

Q. Is there a significant difference between the volume of hydro generation under a 40-year water average model and a median water model?

A. No. When the Company implemented median hydro in the 2010 Rate Case, the change reduced NPC by approximately $1.5 million on a PACW basis. This fact demonstrates that hydro risk is symmetrical.

Q. If poor hydropower is correlated with higher wholesale costs as the Commission concluded in the 2006 Rate Case, does this mean that PacifiCorp's NPC will always increase in a scenario of low regional hydro?

A. Not necessarily. PacifiCorp is often a net seller in the market. Higher wholesale prices can actually mean lower NPC for PacifiCorp, unlike other utilities that are net buyers in the market. In fact, much of PacifiCorp's NPC under-recovery over the past five years is attributable to falling market prices and lower-than-forecast wholesale revenue credits in rates. This fact undermines the key assumptions that led the Commission to conclude in the 2006 Rate Case that PacifiCorp's NPC risk was asymmetrically distributed. For these reasons, the Company has not reflected asymmetrical recovery mechanisms or a cost of capital adjustment[27] in its proposed PCAM.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

[27] In addition, as noted earlier, the Company reviewed the PCAMs of the companies that comprise Dr. Hadaway's comparable group for purposes of estimating the Company's cost of equity. All of these companies have PCAMs and the majority are dollar-for-dollar mechanisms. Given this fact, there is no basis for an adjustment to PacifiCorp's return on equity if its requested PCAM is approved.