CONFIDENTIAL PER WAC 480-07-160
Exhibit No.___(GND-1CT)
Docket UE-14____
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, a division of PacifiCorp Respondent.	Docket UE-14____

PACIFIC POWER & LIGHT COMPANY

REDACTED DIRECT TESTIMONY OF GREGORY N. DUVALL

May 2014

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ATTACHED EXHIBITS

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

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.

Q. Please 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 AND SUMMARY

Q. Please describe the purpose of your testimony.

A. I present the net power costs (NPC) for the pro forma period (the 12 months ending March 31, 2016) and support the various components of NPC. I also address several issues related to NPC, including the Company's loads and sales forecast and coal costs. Finally, I introduce the Company's proposed renewable resource tracking mechanism.

Q. Please summarize your direct testimony.

A. In my testimony, I address the following:

- The Company's NPC for the pro forma period reflect an increase in Washington-allocated NPC of approximately $12.0 million, driven by a reduction in wholesale sales revenue and increases in purchased power expense and coal fuel expense, partially offset by a reduction in natural gas expense.
- The Company proposes to include all power purchase agreements (PPAs) with all qualifying facilities (QFs) located in PacifiCorp's west control area in rates, with costs allocated to Washington in the same manner as all other generation resources under the Commission-approved West Control Area inter-jurisdictional allocation methodology (WCA). Treating QF PPAs in this manner increases the accuracy of the NPC forecast for the west control area. In response to the Commission's rejection of this proposal in the Company's 2013 Washington general rate case, Docket UE-130043 (2013 Rate Case), the Company also describes two alternative approaches to addressing QF PPAs in the west control area.
- The Company's Washington sales and loads increased from those included in the 2013 Rate Case.
- The Company's coal supply costs increased by approximately $2.3 million on a Washington-allocated basis, largely associated with the Jim Bridger plant. The increase in fuel expense at the Jim Bridger plant is a result of higher mining costs at both the Bridger Coal Company (BCC) underground mine and the Black Butte mine.

- The NPC modeling in this case is largely consistent with past cases, with a few exceptions. The Company proposes a new approach to shaping wind generation on an hourly basis, designed to increase the accuracy of the Company's wind generation forecast.
- In response to the Commission's order in the 2013 Rate Case (Order 05), I support the continued use of the Generation and Regulatory Initiative Decision Tools model (GRID) and the application of market caps to regulate GRID's use of off-system sales.
- The Company proposes a renewable resource tracking mechanism (RRTM) to address the variability of NPC related to the increase in intermittent wind resources in the Company's resource portfolio. The RRTM will account for the difference between the normalized value of wind resources included in Washington customers' base rates and the actual value of wind resources during a given year.

PRO FORMA NPC

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

A. The west control area NPC for the pro forma period are approximately $568.8 million. As discussed in Ms. Natasha C. Siores's direct testimony, the Washington-allocated NPC are approximately $130.2 million before applying the production factor.[1] The Company calculated NPC by using pro forma expenses and revenues for the period April 2015 through March 2016 (which corresponds to the rate effective period). Only costs and benefits attributed to the west control area are

[1] Ms. Siores's testimony also addresses the Company's application of the production factor in the calculation of pro forma NPC.

included, and the resulting NPC are then allocated to Washington using the Commission-approved WCA. A report detailing the NPC forecast on a west control area basis is attached to my testimony as Exhibit No.___(GND-2).

Q. How do the pro forma NPC in this case compare to the NPC authorized in the Company's 2013 Rate Case?

A. The pro forma Washington-allocated NPC in this case are approximately $12.0 million higher than the level authorized in the Company's 2013 Rate Case.

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 the pro forma period based on projected data using GRID, a production cost model that simulates the operation of PacifiCorp's power system on an hourly basis.

Q. Is the Company's general approach to the calculation of NPC using GRID the same in this case as in the Company's 2013 Rate Case?

A. Yes. The Company used the same version of GRID as the 2013 Rate Case and used GRID consistently with past cases. As directed by Order 05 in the 2013 Rate Case, my testimony provides support for the continued use of GRID to determine NPC in the Company's general rate cases.

Q. What GRID inputs were updated for this filing?

A. The Company updated inputs to GRID to reflect the information available at the time the Company prepared the NPC study for the current filing. In addition to west control area load, discussed in more detail below, 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 PacifiCorp's generation facilities; and planned and forced outages at PacifiCorp's generation resources.

Q. What reports does GRID produce?

A. The major output from GRID is the NPC report. This is the same information contained in Exhibit No.___(GND-2), and an electronic version is included in my workpapers. Additional data with more detailed analyses are also available from GRID 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. The main contributors to the increase in NPC are a reduction in wholesale sales revenue and an increase in purchased power expense, partially offset by a reduction in natural gas fuel expense. Table 1 below summarizes the changes by NPC category.

Table 1
Net Power Cost Reconciliation

	Washington Allocated ($ millions)
2013 Rate Case	**$118.2**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	$6.9
Purchased Power Expense	$7.8
Coal Fuel Expense	$2.3
Natural Gas Fuel Expense	($6.0)
Wheeling, Hydro and Other Expense	$0.9
Total Increase/(Decrease) to NPC	**$12.0**
2014 Rate Case	**$130.2**

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is primarily due to the expiration of the long-term contract with the Sacramento Municipal Utility District (SMUD) and a reduction in revenue from the assumed sale from the west control area to PacifiCorp's east control area. Revenue attributed to this sale is lower than in the 2013 Rate Case due to a reduction in the price spread between the Mid-Columbia and Four Corners wholesale markets, which is used under the WCA to determine when sales would be made into the east control area.

Q. Is the increase in purchased power expense related to the inclusion of QF PPAs from Oregon and California, an issue discussed in more detail below?

A. Yes. Total purchased power expense is higher than the final outcome of the 2013 Rate Case because the Company includes the costs of PPAs with QFs in Oregon and California in west control area NPC. The increased expenses related to QF PPAs are partially offset by reductions related to purchases from GP Camas and the portion of the Hermiston natural gas generator that is purchased by PacifiCorp. In addition, the volume of short-term market purchases (identified as system balancing purchases) is lower than in the 2013 Rate Case, which is attributable to the reduction in system requirements, such as the expiration of the SMUD contract.

Q. Please explain the reduction in natural gas fuel expense.

A. Natural gas fuel expense is lower mainly due to a reduced volume of natural gas generation attributable to fewer periods when the gas generation is economic in the GRID forecast compared to available wholesale market transactions for electricity.

Q. Have coal costs for the pro forma period increased from the 2013 Rate Case?

A. Yes. As I address in more detail below, compared to the 2013 Rate Case, coal costs increase Washington-allocated NPC by approximately $2.3 million.

Q. Do NPC in this case include the impact of PacifiCorp's participation in an energy imbalance market (EIM) with the California Independent System Operator Corporation (CAISO)?

A. No. EIM costs and benefits are not yet sufficiently known and measurable to include in this filing. The EIM is new and key EIM components are still being developed and implemented. For example, the EIM's target date for full operation is contingent on Federal Energy Regulatory Commission (FERC) approval of amendments to the CAISO tariff and PacifiCorp Open Access Transmission Tariff (OATT), and the successful completion of EIM market simulation and testing. Additionally, imbalance costs and benefits are difficult to forecast and they will vary depending on the amount of transfer capability available for EIM use on the California-Oregon Intertie (COI). PacifiCorp, the Bonneville Power Administration (BPA), and CAISO are working to clarify operational procedures associated with PacifiCorp's use of its existing transmission rights across the COI.

Q. How does the Company report its actual NPC?

A. Consistent with the Company's approach in the 2013 Rate Case (to which no party objected), the Company reports actual NPC per the books and records of the Company for assets included in the west control area. The assets or proportions of assets included in the reporting of actual NPC are the same as used to determine normalized NPC in the Company's general rate cases. The Company accounts for differences in west control area loads and resources by reducing actual short-term balancing purchase or sales transactions.

PROPOSED TREATMENT OF QF RESOURCES IN THE WEST CONTROL AREA

Q. Please explain the Company's proposed treatment of PPAs with west control area QFs.

A. In this case, the Company renews its proposal to include Washington's share of the costs and benefits associated with all PACW (Oregon, California, and Washington) QF PPAs in the calculation of west control area NPC.

Q. Did the Company originally propose this treatment in the 2013 Rate Case?

A. Yes. The Commission rejected this proposal in Order 05 the 2013 Rate Case, and the Company sought judicial review of this issue.

Q. Why is the Company again asking to include the cost of PPAs with QFs in Oregon and California in this case?

A. The Company respectfully asks the Commission to reconsider its approach to including PPAs with west control area QFs in Washington rates for the following reasons:

- Including all PPAs with QFs in the west control area in the NPC calculation is consistent with the treatment of other generation resources under the WCA and is a more accurate representation of the Company's operations in the west control area because these resources are all located in the west control area, physically deliver power to meet Washington load in the same manner as any other west control area resource, and provide direct benefits to Washington customers.
- There are now a material number of QFs serving Washington customers, but the costs of the PPAs with these QFs are not reflected in Washington rates. In the pro forma period, Oregon and California QFs are projected to supply 806,799 megawatt-hours (MWh) of generation in the west control area. Collectively, west control area QFs provide a significant source of power supply to Washington

customers, but Washington customers only pay for PPAs with QFs located in Washington.

- Including west control area QF PPAs in Washington rates is consistent with the Public Utility Regulatory Policy Act of 1978 (PURPA). The QF PPAs included in this case were executed at avoided cost prices calculated under PURPA, and no party has ever alleged that the prices exceed the Company's actual avoided costs at the time the PPAs were executed. PURPA explicitly requires FERC to "ensure that an electric utility that purchases electric energy or capacity from a [QF] . . . recovers all prudently incurred costs associated with the purchase."[2]

- All of the Oregon and California PPAs are with QFs that are eligible resources under Washington's Energy Independence Act (EIA). Allowing the Company to recover the costs of these Oregon and California QF PPAs in rates implements the EIA's policy of encouraging renewable resource development on a regional basis and diversifying the portfolio of renewable resources serving Washington customers.

Q. In the 2013 Rate Case, the Commission reasoned that the Company's proposal was the equivalent of adopting the Revised Protocol method just for QF resources.[3] Do you agree?

A. No. The Company's proposal to include the costs of PPAs with QFs in Oregon and California in the calculation of west control area NPC is consistent with the WCA and strictly tracks the Commission's underlying rationale for the WCA. As reiterated in the 2013 Rate Case Order, the WCA is based "on the generation resources that are actually used to keep the west control area in balance with its neighboring control areas."[4] Oregon and California QFs are used to keep the west control area in balance just like all other west control area generation resources. The only distinguishing

[2] 16 U.S.C. § 824a-3(m)(7)(A); *see also Freehold Cogeneration Assocs., L.P. v. Bd. of Regulatory Comm'rs of the State of N.J.*, 44 F.3d 1178, 1194 (3d Cir. 1995) ("[A]ny action or order by the [state commission] to reconsider its approval or to deny the passage of those rates to [the utility's] consumers under purported state authority was preempted by federal law.").
[3] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-130043, Order 05, ¶ 110 (Dec. 4, 2013).
[4] Order 05 ¶ 110 (quoting *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-061546, Order 08, ¶ 53 (June 21, 2007).

factor between QF resources and all other west control area resources is the fact that PURPA requires the Company to purchase power from QFs at prices established by regulators in west control area states. This mandate makes recovery of the costs of these resources more appropriate under the WCA, not less.

In addition, the 2010 Protocol, which is the current inter-jurisdictional allocation methodology used in the PacifiCorp's other five state jurisdictions, allocates the costs of QF PPAs across PacifiCorp's system. In this case, the Company is not proposing to system-allocate PPAs with QFs in all six states served by the Company.

Q. Are Washington customers harmed because west control area NPC is higher when all PPAs with west control area QFs are included?

A. No. Washington customers are not harmed by paying rates that more accurately represent the cost to serve them. These resources are used in providing service to Washington customers, and including the costs of these resources in rates is fair, not harmful.

Furthermore, while including all west control area QF PPAs increases Washington-allocated NPC by approximately $10.0 million, this only shows that the prices paid for Oregon and California QF resources are higher than the variable cost of market purchases and other resources used to balance the GRID study. QF prices, on the other hand, are established in advance, consistent with PURPA, and are fixed for a number of years over the term of the PPA. Long-term contract prices will inevitably be different from short-term market prices as time progresses. QF prices may also include a capacity component in addition to payment for energy. In

Washington, for example, Schedule 37 rates compensate QFs for both energy and capacity, with energy payments based on the incremental cost of market transactions and thermal output, and capacity payments reflecting the fixed costs of a simple cycle combustion turbine for three months per year. If avoided cost prices are greater than market prices years after the PPA was signed, it does not mean that the avoided cost prices in the QF PPA are excessive or otherwise violate PURPA's strict requirements.

PURPA requires that the prices paid to QFs be equal to a utility's avoided cost of energy and capacity. Each state has an approved method for calculating these avoided costs, and the resulting prices are heavily scrutinized and ultimately approved by the respective regulatory commissions. The avoided cost calculation is intended to ensure that customers are indifferent to QF generation, *i.e.*, that the price paid to the QF is the same as the price the utility would otherwise incur if it was generating the electricity itself. Comparing QF PPA prices for a single test year to the variable cost of market purchases or the Company's existing resources is insufficient to determine whether QF prices are reasonable and prudent from a ratemaking standpoint.

Q. In response to Order 05 in the 2013 Rate Case, did the Company analyze other approaches to addressing Oregon and California QF PPAs in Washington?

A. Yes. In an effort to respond to the Commission's concerns in Order 05 about including the energy and capacity costs of all west control area QF PPAs in the determination of west control area NPC, the Company examined two alternative approaches to addressing the Oregon and California QF PPAs:

1) A "load decrement" approach, which excludes the costs and energy of Oregon and California QF PPAs from the NPC calculation, and excludes an equivalent

amount of QF output from WCA loads used to calculate NPC and inter-jurisdictional allocation factors; and

2) A "Washington re-pricing" approach, which includes Oregon and California QF PPAs in the NPC calculation but re-prices them using the Washington avoided cost rates in effect at the time of PPA execution.

Table 2 below compares the revenue requirement impact of these two alternative approaches with the Company's proposal to include all west control area QF PPAs as west control area resources. This table, and supporting detail, is provided in Exhibit No.___(NCS-7) accompanying Ms. Siores testimony.

Table 2

	Revenue Requirement	Variance from Filed
As Filed	$27.2 million	
Washington Re-Pricing	$24.9 million	($2.3 million)
Load Decrement	$23.1 million	($4.1 million)
Situs Assigned (exclude OR and CA QF PPAs)	$17.2 million	($10.0 million)

Q. Please explain the load decrement approach.

A. Under this approach, Oregon and California QF PPAs are deemed to serve customers in those states, consistent with the situs treatment ordered by the Commission in the 2013 Rate Case. Because Oregon and California QF PPAs are not recognized as WCA resources, the costs and related energy are removed from the calculation of west control area NPC. Next, because Oregon and California QF PPAs are deemed to serve customers in those states, the retail load in those states served by these resources is also removed from the calculation of west control area NPC. Finally, the retail load in Oregon and California served by QF resources is subtracted (*i.e.* decremented) from the energy and peak loads used to determine each state's allocation factors under the WCA.

Q. What is the impact to Washington of removing Oregon and California QF PPAs and load?

A. Removing Oregon and California QF PPAs and load reduces west control area NPC and reduces the total load served by west control area resources. The allocation of remaining west control area costs is adjusted to account for the decremented load—*i.e.* the share of the total costs allocated to Oregon and California is decreased reflecting the reduced requirement to serve customers in those states. Washington's allocated share of remaining WCA costs is increased as a result of the QF-PPA-related decrements to Oregon and California load. The net impact is a reduction to the Company's current filing of approximately $4.1 million.

Q. Why is an adjustment to the inter-jurisdictional allocation factors required under the load decrement approach?

A. Adjusting the inter-jurisdictional allocation factors under the load decrement approach ensures that the full impact of treating QF PPAs as situs resources is reflected in Washington revenue requirement. If Oregon and California customers are being served by specific resources, they should not also be allocated the cost of the remaining west control area resources. Decrementing Oregon and California load for allocation purposes appropriately reduces the share of west control area costs allocated to those states.

Q. Please explain the alternative approach of re-pricing Oregon and California QF PPAs using Washington avoided costs.

A. Under this alternative, the Oregon and California QF PPAs are included in west control area NPC but are re-priced using Washington avoided cost rates that were calculated at the time the PPA was signed. This alternative removes the impact of differences in individual state commission approaches to determining avoided cost prices. Some of the Oregon and California QF PPAs have contract terms that extend beyond the last year for which the Company had calculated avoided cost prices in Washington. For example, an Oregon QF PPA signed in June 2009 would be priced using the Washington Schedule 37 prices approved by the Commission in February 2009, which were only calculated through 2013. In examples such as this, the last annual price was escalated with inflation through the pro forma period. Several Oregon and California QF PPAs in the pro forma period were signed in the early 1980s, and one was signed in the early 1990s. At that time, the Company also had two-long term QF PPAs in Washington, one with the City of Walla Walla (signed in 1984) and one with Yakima-Tieton Irrigation District (signed in 1985). Prices paid under the Walla Walla PPAs were applied to the early-1980s contracts in Oregon and California, and prices paid under the Yakima Tieton PPA were applied to the PPA signed in 1993.

Q. Currently, the Company's Schedule 37 only allows fixed-price contracts for a term of up to five years. Has that always been the case?

A. No. Schedule 37 was first implemented in 2004, and it included a five-year limit on fixed-price contracts. However, the two long-term Washington QF PPA contracts signed in the 1980s mentioned above were for terms of 25 and 20 years, respectively. Washington's current administrative rules allow a utility to sign contracts for electricity purchases for any term up to twenty years.[5]

[5] WAC 480-107-075(3).

Q. What is the impact to Washington NPC of re-pricing all of the Oregon and California QF PPAs?

A. As shown in Table 2, the impact of re-pricing all of the Oregon and California QF PPAs using contemporaneous Washington avoided cost rates is a reduction to the Company's current filing of approximately $2.3 million.

Q. Why is the Company discussing these alternative methods in this case?

A. The Company's proposal for treatment of west control area QF PPAs in this case is the same as in the Company's 2013 Rate Case—full recognition of the costs of the Company's PPAs with Oregon and California QFs in Washington rates. The Company renews this proposal because it best captures the prudent and reasonable costs to serve Washington customers. But in response to the Commission's past criticism of its proposal, the Company provides the alternative methods as a middle ground between full recovery or full disallowance of the costs of all west control area QFs in Washington NPC.

CHANGES IN SALES AND LOADS

Q. Please summarize the changes in Washington sales in this case compared to the Company's 2013 Rate Case.

A. As shown in Table 3 below, the Company's Washington sales in the historical test period (the 12 months ended December 31, 2013) were 9,549 MWh, or 0.2 percent higher than the sales included in the 2013 Rate Case on a weather-normalized basis.[6] The increase in sales is largely driven by increased sales to the commercial class and

[6] In this case, the Company calculated temperature normalization for the residential, commercial, and irrigation customers consistently with the methodology approved by the Commission in the Company's 2005 general rate case, Docket UE-050684, 2006 general rate case, Docket UE-090205, and the Company's 2013 Rate Case, Docket UE-130043.

is offset in part by a decrease in sales to the residential, industrial, and irrigation classes.

Table 3

Washington Sales Comparison* (MWh)				
	2014 Rate Case 12 ME Dec-13	2013 Rate Case 12 ME Jun-12	Difference	Percentage Change
Residential	1,580,882	1,605,237	(24,355)	-1.5%
Commercial	1,481,385	1,411,378	70,006	5.0%
Industrial	790,071	821,044	(30,972)	-3.8%
Irrigation	148,533	153,555	(5,022)	-3.3%
Lighting	9,290	9,398	(108)	-1.1%
Total	4,010,161	4,000,612	9,549	0.2%
* At meter				

Q. How are the temperature normalized sales and load for the historical test period used in this case?

A. The temperature normalized retail sales are used by Ms. Joelle R. Steward to develop present revenues and proposed rates, and Ms. Siores uses the test period temperature normalized loads to calculate inter-jurisdictional allocation factors under the WCA.

Q. Please summarize the changes in load for the pro forma period compared to the 2013 Rate Case.

A. As shown in Table 4 below, the temperature normalized forecasted load for the 12 months ending March 2016 is higher than the loads for Washington and the west control area forecasted in the 2013 Rate Case, which were based on the 12 months ending December 2014.

Table 4

Comparison of WCA Loads* in Net Power Costs				
State	2014 WA GRC 12 months ending Mar-16 (MWh)	2013 WA GRC 12 months ending Dec-14 (MWh)	Difference	Percentage Difference
Washington	4,421,740	4,369,000	52,740	1.2%
Oregon	14,714,670	14,711,436	3,234	0.0%
California	883,290	894,220	-10,930	-1.2%
System Load	20,019,700	19,974,656	45,044	0.2%

*At system input (includes losses)

The increase in the load forecast in this case is driven by greater economic activity related to fruit processing and refrigeration in the Washington commercial class, offset by growth in energy efficiency and conservation programs in the residential class.

Q. How are the forecasted loads for the west control area used in preparing this case?

A. I use the forecasted loads for the west control area to calculate net power costs.

Q. Please list the assumptions and updates to the current load forecast.

A. The Company updated the following information in the current load forecast:

- Actual sales January 1997 through August 2013.
- Load research data through December 2012 updated in the temperature normalization model.
- Actual weather was rolled forward one year to the 1993-2012 time period (measured at Yakima, Washington).
- Updated information from IHS Global Insight of economic data, such as households, population, and employment figures.

PRO FORMA COAL COSTS

Q. Has the pro forma coal expense in this case increased from levels reflected in the Company's 2013 Rate Case?

A. Yes. Pro forma coal fuel expense has increased by $2.3 million on a Washington-allocated basis, from $48.3 million in the 2013 Rate Case to $50.6 million in this case. Reduced volumes account for an approximate $0.4 million decrease and higher coal prices account for a $2.7 million increase.

Q. What are the primary drivers of the increase in coal prices?

A. The increase in coal prices reflect:

- A [redacted] million Washington-allocated increase in Colstrip plant costs based on Westmoreland's most recent Annual Operating Plan (AOP).
- A [redacted] million Washington-allocated increase at the Jim Bridger plant reflecting price increases in both the BCC and Black Butte coal supplies.

Q. Please explain the coal supply arrangements for the Colstrip plant.

A. The Colstrip mine is supplied by Western Energy's Rosebud mine. Pro forma period costs were developed based on Western Energy's 2014 AOP for the Rosebud mine published in fall 2013.

Q. Please describe the increase associated with the Colstrip supply.

A. Pro forma costs increased from [redacted] per ton in the 2013 Rate Case to [redacted] per ton in this case, or by [redacted] per ton. Approximately [redacted] per ton of the increase is associated with increased mine operating costs and approximately [redacted] per ton is associated with increased royalties and taxes. The increase in mine operating costs reflects a slight change in stripping ratio (6.8 to 7.0 bank cubic yards/ton exposed), increased interim reclamation expense, and increases in labor, benefits, materials, and supplies.

Q. Please explain the coal supply arrangements for the Jim Bridger plant.

A. Similar to the 2013 Rate Case, the Jim Bridger plant is expected to be supplied by a combination of supplies from BCC and the Black Butte mine. In the 2013 Rate Case, 68 percent of the Jim Bridger plant was expected to be supplied by BCC; comparatively, BCC supplies 85 percent of the plant requirements in this case.

Q. Why is BCC supplying a greater proportion of the plant requirements in this case?

A. The increased production reflects PacifiCorp's efforts to optimize production of BCC's surface and underground operations while it continues to evaluate Black Butte coal supplies after the expiration of the current coal supply agreement.

Q. Please describe the increase in coal supply to the Jim Bridger plant.

A. Pro forma costs increased from $[redacted] per ton in the 2013 Rate Case to $[redacted] per ton in this case, or by $[redacted] per ton, reflecting increases in both BCC and Black Butte supply costs.

Q. Please explain the Black Butte coal supply agreement.

A. The current Black Butte coal supply agreement extends through 2014, with extension into 2015 to allow for delivery of previously deferred contract tonnage. The previously deferred contract tonnage is projected to be delivered in the first quarter of 2015.

Q. If the current Black Butte coal supply agreement terminates by the first quarter of 2015, what is the basis for the pro forma Black Butte costs in this case?

A. The Company assumed the same pricing terms used for delivery of contract deferred tonnage in the first quarter of 2015. The Company used a Black Butte Free-on-Board (F.O.B.) mine price of $[redacted] per ton, representing a $[redacted] per ton increase above the $[redacted] per ton F.O.B. mine price used in 2013 Rate Case.

Including Union Pacific rail transportation costs from the Black Butte mine to the Jim Bridger plant and application of anti-freeze agent to the railcars during the winter months, the delivered cost of Black Butte coal will increase from $[redacted] per ton in the 2013 Rate Case to $[redacted] per ton in this case, or by $[redacted] per ton.

Q. Is the Company projecting a similar increase for pro forma BCC costs?

A. Yes. BCC costs will increase from $[redacted] per ton to $[redacted], or by $[redacted] per ton. As reflected in Confidential Table 5 below, the increase in pro forma BCC costs is primarily associated with the BCC underground mine.

Confidential Table 5

[redacted]

Q. Please explain why coal production from BCC's surface mine is increasing almost 300 percent in the pro forma period.

A. The increase in BCC surface production coincides with the expiration of the current Black Butte coal supply agreement and reflects an increased optimization of BCC assets. BCC is able to use both draglines in surface coal production on a full time basis and distribute the fixed and non-variable charges over increased production.

Q. Please explain the cause of the increased costs of coal from the BCC underground mine.

A. The increase in BCC underground mine costs in the pro forma period is a result of significant changes in the underground mine plan. The amount of coal produced by the continuous miners has increased from 17.6 percent of the underground mine production in the 2013 Rate Case to 23.7 percent in this filing. This increase reflects the impact of bypassing the 12th right longwall panel due to high ash content, the shortening of the longwall panels, and three longwall moves instead of two in the pro forma period. Bypassing and shortening longwall panels require additional continuous miner production, which increases production costs. The variable cost of production for a longwall ton is within a range of $[redacted] per ton to $[redacted] per ton, compared to $[redacted] per ton to $[redacted] per ton for continuous miner production.

Q. How do the pro forma BCC costs compare to Black Butte supply costs?

A. On a delivered cost basis, BCC and Black Butte are essentially the same, $[redacted] per ton versus $[redacted] per ton.

SPECIFIC NPC MODELING ISSUES

Q. Has the Company modeled NPC in accordance with Order 05 in the 2013 Rate Case?

A. Yes. The Company's current filing is consistent with Order 05 in the 2013 Rate Case, as follows:

- *Imputed East Control Area (ECA) Sale*—An imputed sale from the west control area to the east control area is included.

- *DC Intertie*—The cost of transmission rights on the BPA Direct Current (DC) Intertie transmission line is included in NPC, and the related transmission capacity and access to the Nevada-Oregon Border market hub are included in the GRID topology.
- *Jim Bridger Coal Costs*—Coal supplied by BCC, an affiliate mine, to fuel the Jim Bridger plant is included based on the cost of production during the pro forma period.
- *Heat Rates*—Normalized heat rates for thermal generating plants are based on a historical 48-month average, with the exception of Colstrip Unit 4 as described below.
- *Hedging Costs*—Hedging costs are included in NPC, valued using the Company's official forward price curve.
- *Market Caps*—Market caps are modeled in GRID based on the 48-month historical average of short-term firm sales (STF) transactions at wholesale market hubs. In response to the Commission's directive, later in my testimony I provide support for continued application of the 48-month average market caps.

In addition, consistent with Order 05 in the 2013 Rate Case, the Company has continued to reflect all costs and benefits associated with the full capacity of the 200 megawatt (MW) point-to-point wheeling contract with Idaho Power Company, and holding reserves to integrate third-party wind resources located in PacifiCorp's west control area.

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

A. NPC for the pro forma period in the current filing include the following adjustments ordered by the Commission in past cases:

- Prorated wheeling expenses for Colstrip Unit 4 based on the transmission capacity from Colstrip to the west control area, instead of splitting equally between the west and east control areas;
- 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.

Q. Have you continued to model the outage rate at Colstrip Unit 4 at eight percent rather than relying on the historical 48-month average?

A. Yes. In Docket UE-100749 (2010 Rate Case), the Commission approved an adjustment to limit the forced outage rate to eight percent for Colstrip Unit 4. In that case, the Company included a seven-month outage at the plant during 2009 in the 48-month historical average, increasing the calculated outage rate used in GRID. The Commission determined that the extended outage should not be included in the historical average because the result was less predictive of what may occur in the future.

In the current filing, the 48-month historical outage rate for Colstrip Unit 4 is again influenced by an extended forced outage, this time during 2013. Consequently, the Company has continued to limit the normalized outage rate to eight percent. On

July 26, 2013, the Company filed an application for deferred accounting in Washington seeking recovery of outage-related costs (Docket UE-131384).

Q. Has the Company made any refinements to the way it models NPC since the 2013 GRC?

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

- *Wind Generation Profile*—The Company continued to model wind generation using the median, long-term forecast to determine the total annual energy, but shaped hourly wind generation profiles using actual 2012 energy output data from PacifiCorp's owned and purchased wind facilities. The net impact of this change is an increase to Washington-allocated NPC of approximately $148,000. Additional details supporting this change are provided below.
- *Leaning Juniper Output and Revenue*—PacifiCorp will receive a small amount of revenue associated with its Leaning Juniper facility due to a contract unique to that wind project. As a result of the contract, output at Leaning Juniper is forecast at a slightly reduced level. A confidential copy of the executed contract is provided in my workpapers. The net impact of this change is an increase to Washington-allocated NPC of approximately $1,325.
- *Network Reliability*—FERC recently approved two changes to network reliability standards affecting the level of reserves the Company holds on its system. First, changes to BAL-002-WECC-2 modify contingency reserve requirements, effective October 1, 2014. The current standard requires contingency reserves equal to the sum of five percent of the load responsibility served by hydro

generation and seven percent of the load responsibility served by thermal generation. Wind and solar are treated the same as hydro generation. The new standard requires contingency reserves equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation. Second, BAL-003-1 includes requirements pertaining to the provision of reserves for frequency response effective April 1, 2015. The impact of both of these standards is included in GRID, increasing Washington-allocated NPC by approximately $97,000.

Wind Generation Profile

Q. Please explain how the Company has historically modeled wind generation in GRID.

A. Total energy from wind generation is included in GRID as a static profile 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 actual output. Typically such a forecast is developed by a third party for an individual wind project by combining wind speed measurements taken before project construction with a detailed model of turbine locations and performance characteristics. The projected output in a given hour is then averaged across each month to develop a 12-month-by-24-hour matrix of average hourly output.

The Company previously input wind generation into GRID using the P50 forecast divided into six four-hour blocks per day. Generation was flat over each four-hour block, and each period was the same for every day during a month.

Consequently, the wind generation in GRID exhibited very little variation, which is inconsistent with operational reality.

Q. Please describe the wind modeling change you propose in this case.

A. The Company continues to use the P50 forecast to determine total wind generation, but now uses the actual 2012 energy output data from the Company's owned and purchased wind facilities to shape hourly wind generation profiles. The Company scales actual hourly generation levels up or down so that when the output within the traditional four-hour blocks is averaged over the course of a month, it is the same as the P50 forecast. In other words, the total energy output of the wind facilities is the same as the P50 forecast energy output used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2012.[7]

Q. Why did the Company refine the modeling of its hourly wind profiles to reflect historical performance?

A. The refinement improves the accuracy of the Company's NPC forecast by using the most recent reliable data available to develop wind profiles that capture the volatility of wind generation in pro forma NPC. Figure 1 below illustrates the difference in the two approaches to developing wind generation profiles. The darker line with smooth step changes represents the previous wind inputs using four-hour blocks. The highly variable line represents the wind inputs that vary hourly based on historical volatility, with the same total wind generation volume as the P50 forecast.

[7] The Company's refinement here is not the same as its proposal in the 2013 Rate Case. In the 2013 Rate Case, the Company proposed to model wind generation based on the 48-month average historical generation, rather than the P50 forecast. In response to parties' concerns, the Company agreed to continue to use the P50 forecast to determine wind generation levels. The refinements in this case continue to use the P50 forecast, consistent with parties' recommendations in the 2013 Rate Case.

Figure 1

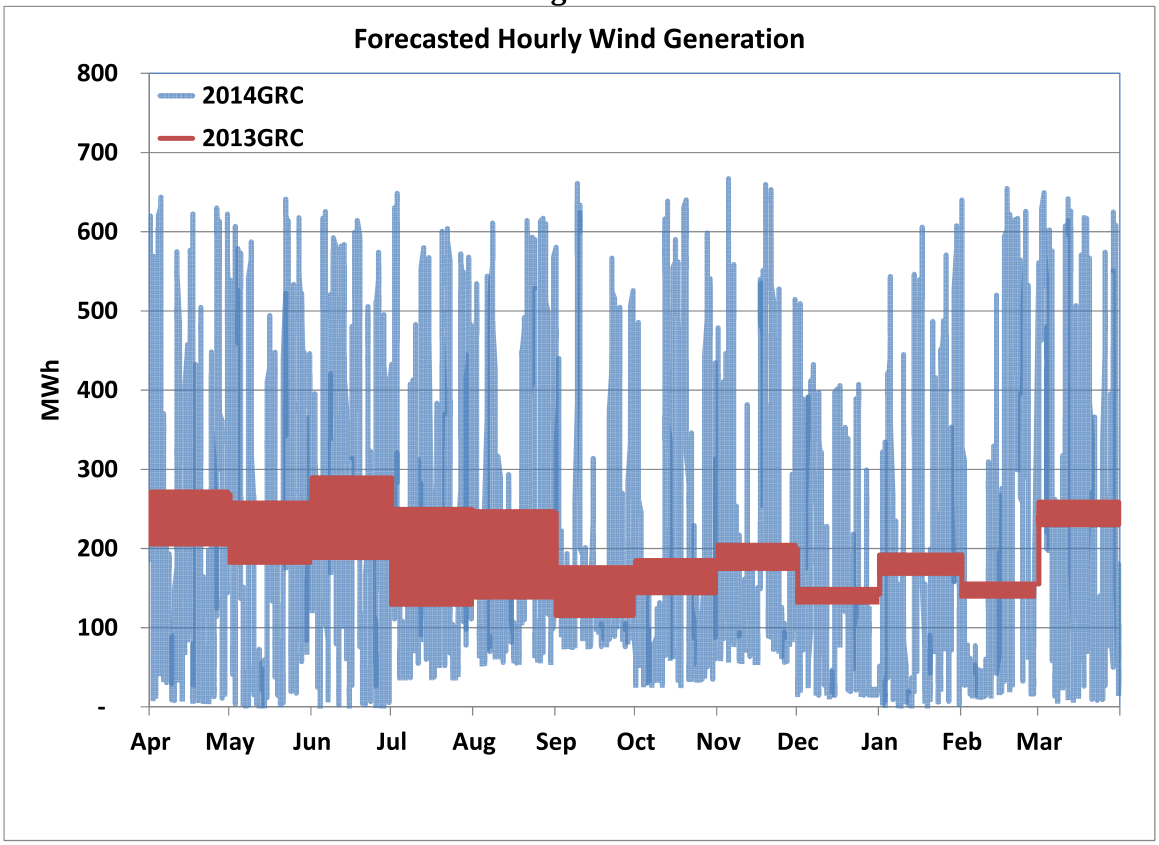

Figure 1 shows that an average wind generation forecast shaped over flat, four-hour blocks does not capture the actual variability associated with wind generation on the system. Applying the 2012 actual wind generation pattern to the total P50 volumes improves the accuracy of pro forma NPC by capturing more of the cost impacts associated with intermittent wind generation on an hourly basis using the most recent data available.

Q. Why is the Company using a single year, in this case 2012, to derive an hourly shape for wind energy?

A. The Company uses 2012 data because it represents the most recent calendar year data available at the time NPC were prepared. The use of a recent calendar year period enables consistent hourly shaping across the Company's wind portfolio as modeled for this case, as projects that came online more recently would not have data available from earlier periods.

Q. Is there evidence supporting the Company's proposed wind shaping methodology?

A. Yes. Exhibit No.___(GND-3) includes a technical report published by the National Renewable Energy Laboratory (NREL),[8] which examined the variability in wind generation over various lengths of time. The report found that "one can expect relatively large inter-annual changes," but concluded that "short-term wind power fluctuations do not exhibit year-to-year variability."[9]

Q. How does the NREL report support the Company's wind shaping methodology?

A. The Company's methodology ensures that average monthly energy output in each four-hour block remains at the P50 forecast, so it will not result in inter-annual changes in output. Because short-term wind power fluctuations are not expected to vary significantly from year to year, the use of the most recent year will not have significant differences in variability compared to other years.

Q. Has the Company prepared an analysis of the variability of its wind plants similar to the analysis presented in the NREL report?

A. Yes. In its study, NREL calculated the coefficient of variation (COV), defined as the ratio of standard deviation value to plant nameplate capacity, to gauge the short-term variability of wind generation. The Company applied this same calculation on four of its wind resources located in the west control area. Table 6 below shows that the COV

[8] Y. H. Wan, *Long-Term Wind Power Variability*. Technical Report, NREL/TP-5500-53637 (Jan. 2012). Retrieved online at http://www.nrel.gov/docs/fy12osti/53637.pdf.
[9] *Id.* at 12.

of the wind plants is fairly consistent over time. It also shows that the variability in the Company's revised modeling is much closer to the historical levels.

Table 6
Yearly COV Value of Hourly Wind Power
(Normalized to Plant Nameplate Capacity)

Year	Leaning Juniper	Goodnoe Hills	Combine Hills	Marengo I & II
2006			0.39	
2007	0.35		0.38	
2008	0.36		0.37	
2009	0.35	0.32	0.37	0.33
2010	0.32	0.29	0.36	0.32
2011	0.31	0.30	0.37	0.34
2012	0.28	0.30	0.36	0.33
Average	0.33	0.30	0.37	0.33
Previous Methodology	0.11	0.10	0.11	0.07
Revised Methodology	0.27	0.29	0.33	0.30

Q. Has PacifiCorp modeled wind generation using an actual hourly shape in filings in other states?

A. Yes. The Company began modeling wind generation using an actual hourly shape in its 2013 transition adjustment mechanism filing in Oregon, docket UE 264. The Public Utility Commission of Oregon approved the company's proposal in that case. The Company has since made filings in Oregon, Utah, and Wyoming using the same method.

Market Caps

Q. Please explain what is meant by the term "market caps."

A. Market caps are limits placed on the potential volume of off-system sales transactions in GRID. These limits have always been included in the Company's GRID modeling, based on actual transaction data. Without market caps, GRID would allow sales at every market at any time of the day or night until transmission or generation constraints are met without regard to depth of wholesale market demand. Historical STF transactions show that this level of sales does not occur in actual operation.

Q. Does the inclusion of market caps as an exogenously determined limit in GRID signify that the model is deficient?

A. No. GRID was designed to replicate PacifiCorp's system operations to the greatest extent possible. Market caps are a required parameter to increase the accuracy of the modeled interaction with off-system counterparties on the boundaries of PacifiCorp's system. Without a specified ability to transact at a given market hub, GRID assumes unlimited market depth for STF transactions; it does not consider regional load requirements, all third-party transmission constraints, market illiquidity, or the dynamic response of market prices as volumes increase. Market caps are a surrogate for these actual market constraints to ensure that GRID does not model transactions and impute sales revenues that, in reality, are not available to the Company.

Q. How does the GRID model forecast off-system sales?

A. On an hourly basis, GRID balances all loads and resources within individual areas, or "bubbles," included in the model topology. The GRID topology represents only PacifiCorp's balancing authority areas (BAAs) and does not include other BAAs in the surrounding region. The GRID topology includes PacifiCorp's access to various wholesale markets based on existing transmission rights. After all PacifiCorp system obligations (*i.e.*, retail load, wholesale obligations, and reserve requirements) are met, GRID is able to sell any remaining economic resources into the wholesale markets up to the Company's available transmission rights. GRID will also take advantage of price differences at distinct wholesale market hubs by buying power at a low price to sell at a higher price in another market, subject to transmission availability.

Q. Do all production cost models require the same type of market caps?

A. No. Each model is unique and may or may not require an exogenously determined limit on wholesale market transactions like GRID. For example, some models include loads and resources for an entire region. Individual utility systems within the region are allowed to interact, and the model determines a market clearing price at different points based on the loads and resources of all the surrounding areas. In such a model, a specified market cap is not needed because load and resources from all market participants are included in the model and balanced simultaneously. However, market activity is limited by the surrounding load, resources, and transmission constraints.

Q. Did the Commission address market caps in the 2013 Rate Case?

A. Yes. In Order 05 in the 2013 Rate Case, the Commission considered the use of market caps as proposed by the Company along with an adjustment proposed by Boise White Paper to eliminate the market caps, or in the alternative, increase the cap levels based on the calculation adopted by the Oregon commission.

Q. Did the Commission reject Boise White Paper's adjustment to market caps?

A. Yes. The Commission found that eliminating the market caps "does not appear to lead necessarily to more accurate results" and that "eliminating market caps with no other refinements to the GRID model could lead to even more inaccurate results."[10] The Commission found in favor of maintaining the Company's method, but directed

[10] Order 05 ¶ 154.

"the Commission's regulatory staff to engage with PacifiCorp, and others if appropriate, to find a better, more accurate approach to this problem."[11]

Q. Did the Company meet with the Commission staff and other parties to discuss the market cap issue?

A. Yes. On March 19, 2014, the Company met with Staff, Public Counsel, and Boise White Paper to discuss the GRID model and the market caps issue.

Q. Were parties able to agree on a different approach to market caps in GRID?

A. No. The discussion centered on the alternatives presented in the 2013 Rate Case (*i.e.*, computing the caps based on an historical average or historical maximum transaction volume), but no agreement was reached on the appropriate method going forward.

Q. Please describe how the Company determines market caps in GRID.

A. The Company's market cap calculation first determines the market depth or potential amount of market sales historically transacted by PacifiCorp. The market depth is defined by the average level of STF sales transacted by PacifiCorp during the 48-month historical base period (differentiated by month and by on- and off-peak periods). The average historical level of STF transactions is then reduced by any actual STF transactions executed on a forward basis and included in the normalized NPC study in this case. In other words, the market caps are defined by the potential level of transactions, net of transactions that PacifiCorp has already entered into for the pro forma period.

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[11] *Id.* ¶ 155.

Q. Please describe the alternative method approved by the Oregon commission.

A. Under the Oregon method, market caps are defined by the maximum volume of transactions during the 48-month historical base period, differentiated by month and by on- and off-peak periods.[12] In the 2013 Rate Case, Boise White Paper advocated for this method as an alternative to eliminating market caps altogether, arguing that setting the market caps based on an average eliminates some transactions.

Q. Do you agree that using a historical maximum is superior to the 48-month average?

A. No. Basing the market cap on the maximum transaction volume of any month and diurnal period within the 48-month historical period does not reflect a normalized level of sales that properly takes into account changing market conditions over longer periods of time. The peak volume of historical actual wholesale transactions may have been due to unexpected wind generation, changes in prices, or off-system contingency events. The GRID model, however, does not reflect these types of events because it uses static wind and market price forecasts and normalized assumptions for thermal generating units. While there may be specific hours in which the market caps are set below actual sales levels, there are many more hours in which the market caps are set above actual sales levels. In this way, the Oregon approach makes the market caps less restrictive without regard to whether the redesigned caps replicate actual market conditions.

[12] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 5-8 (Oct. 29, 2012).

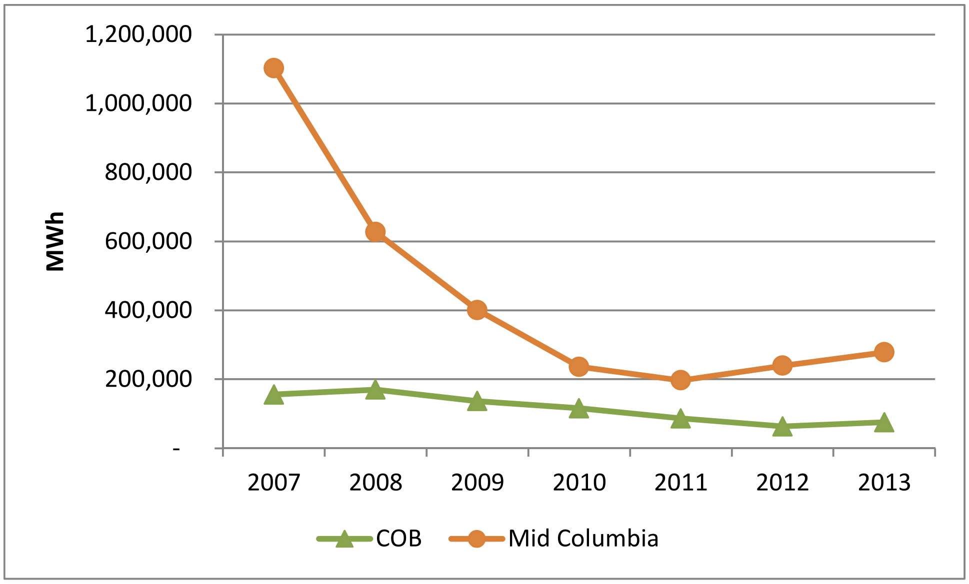
Q. Can you provide an example of how the Oregon approach fails to replicate actual market conditions?

A. Yes. Consider a year where, due to weather or some other system condition, PacifiCorp's sales at a particular market hub during March were exceptionally high, but returned to normal in April. The next year, sales at the same market hub were normal in March but exceptionally high in April. The Oregon approach would determine the market caps based on the exceptionally high sales volumes in both March and April. This distorts the pattern of market behavior within a year and would allow an ongoing level of sales in GRID that is higher than historical actual sales, which undermines the accuracy of the NPC forecast.

Q. Do you have any other concerns over the use of the Oregon approach?

A. Yes. PacifiCorp's STF sales transactions have decreased significantly over time, as shown in Figure 2 below. Similar to other normalizing adjustments such as forced outage rates, using a 48-month average to calculate market caps results in a normalized level of sales that can reasonably be expected during the pro forma period based on recent experience.

Figure 2
STF Sales Transactions



Market caps calculated using the maximum transactions over the historical period would not appropriately account for trends such as the decline in sales at the Mid-Columbia market shown in Figure 2 because the maximum volume transactions would be concentrated in a single year rather than equally weighted to all years.

Q. Has the Company quantified the impact of the Oregon method in this case?

A. Yes. Using the highest average monthly on- and off-peak periods during the 48-month historical period to determine the market caps reduces Washington-allocated NPC by approximately $1 million.

Continued Use of GRID

Q. Did the Commission request further review of GRID in its order in the 2013 Rate Case?

A. Yes. In the 2013 Rate Case, the Commission ordered the Company to "engage with Staff, Public Counsel, and others, to discuss whether the GRID model can be made more transparent, or should be replaced, to increase the Commission's level of confidence in PacifiCorp's net power cost forecasting."[13] The Commission directed the Company to address the continued use of GRID in its next general rate filing.

Q. Did the Company discuss GRID and its use in rate cases with Staff, Public Counsel, and other parties as directed?

A. Yes. On February 19, 2014, the Company met with the Staff and discussed, among other items, the Commission's directive regarding use of GRID. On March 19, 2014, as discussed above, the Company met with Staff, Public Counsel, and Boise White Paper to discuss GRID.

Q. What feedback did the Company receive regarding the transparency of GRID and its continued use in rate filings?

A. While the parties generally agreed that GRID's modeling assumptions should be justified by the Company and scrutinized by intervenors, no party expressed concern that GRID was seriously flawed or that its use should be discontinued. The Company expressed its willingness to work with interested parties to increase their understanding and the transparency of GRID.

Q. The Commission compared GRID to another forecasting model, AURORA, which is used by other Washington utilities.[14] Has the Company reviewed the AURORA model?

A. Yes. As part of the settlement approved in Docket UE-111190 (2011 Rate Case) the Company agreed to "[e]valuate the AURORA power cost dispatch model for use in PacifiCorp's future Washington general rate cases or other net power cost filings

[13] Order 05 ¶ 156.
[14] *Id.* ¶ 156.

where the Company currently relies upon the GRID power cost dispatch model."[15] Between May 2012 and August 2012, the Company worked directly with EPIS, Inc., owner of the AURORA model, to evaluate whether it was a viable alternative to GRID for calculating NPC in the Company's rate filings. In August 2012, with the support of the stipulating parties in docket UE-111190, the Company suspended its evaluation.

Q. Why did the Company suspend its evaluation of the AURORA model?

A. As of August 2012, after approximately three months of testing and evaluation, the Company could not conclude that the AURORA model accurately represented PacifiCorp's system operation. The Company and the parties agreed that significant time and effort would be required to continue testing and refining the AURORA model for use in the Company's rate filings. Given the uncertainty of the outcome, the parties agreed to suspend the evaluation.

Q. Does the Company propose to continue use of GRID to determine NPC in Washington rate filings?

A. Yes. The Company believes GRID is a reasonable tool for developing normalized power costs specific to PacifiCorp's unique system. The Company cannot reasonably predict if a third-party software package will have the ability to accurately represent the specific complexities of PacifiCorp's system. Furthermore, the complexity of determining the Company's NPC will not diminish with the use of a different modeling tool. GRID has been used in rate cases and numerous other regulatory filings in six states for over a decade and has been improved along the way in part

[15] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-111190, Order 07, ¶ 20 (Mar. 30, 2012) (footnotes omitted).

based on feedback and adjustments proposed by intervenors and regulators. The Company is committed to enabling access to the model and enhancing the transparency of its results.

RENEWABLE RESOURCE TRACKING MECHANISM

Q. Please describe the Company's proposed RRTM.

A. The Company proposes to establish an RRTM to allow the Company to collect or credit the differences between the value of resources included in Washington rates and eligible to comply with Washington's renewable portfolio standard (RPS) established in the EIA,[16] and the actual value of these resources used to serve Washington customers. On a monthly basis, the Company will compare the actual value of RPS-eligible generation and related production tax credits (PTCs) to the forecasted level included in the GRID run used to set base rates. Washington's allocated share of any differences will be deferred in a balancing account, and the monthly under- or over-recovery will accumulate in the balancing account, with interest. The Company will make an annual filing in July of each year to collect from or credit to customers the accumulated balance over the subsequent year. The Company proposes to implement the RRTM beginning with the effective date of new rates in this case.

Q. Why is the Company proposing an RRTM in Washington?

A. The Company's NPC is subject to a high degree of variability driven by factors largely outside of the Company's control, including variations in generation from resources used to comply with Washington's RPS. The passage of the EIA in 2006

[16] The EIA is codified at RCW 19.285.

removed a significant part of the Company's discretion in selecting the power supply used to serve Washington customers, mandating procurement of certain levels of renewable generation resources. At the same time, the EIA requires customers to bear the costs of prudent compliance.

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

A. Under RCW 19.285.050(2), an "investor-owned utility is entitled to recover all prudently incurred costs associated with compliance with this chapter."

Q. How will the Company calculate the value of the resources in the RRTM?

A. For resources in the west control area, the Company will calculate forecast value of the output included in base rates by multiplying the forecast generation by the forecast market prices used in the GRID model. The actual value will be calculated by multiplying actual generation by actual market prices. For wind resources purchased from third parties, the forecast and actual purchase costs will be subtracted from the respective market value. The difference between the actual and forecast value of generation will be included in the balancing account for later recovery from or refund to customers, as described above. The Company will also compare the amount of PTCs forecasted in rates for Company-owned facilities to the actual PTCs received, with the difference included in the balancing account.

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

A. No. The Company proposes a dollar-for-dollar true-up to the actual value of RPS resources included in Washington rates used to serve Washington customers. The RRTM is a more limited mechanism than the power cost adjustment mechanisms

(PCAMs) previously proposed by the Company, focusing only on renewable resources and relying on the specific cost-recovery provisions of the EIA.

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

A. No. The Commission did not require deadbands or sharing in allowing a hydro generation deferral for PacifiCorp in the past,[17] demonstrating the Commission's view that the design of cost recovery mechanisms "must take into account the specific circumstances facing the utility," and that they "need not be the same."[18]

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 years since enactment of the EIA, the Company's Washington NPC recovery shortfall exceeded $50 million.[19] PacifiCorp's renewable resources have contributed to this under-recovery by increasing the complexity and variability of normal system operations and the challenges of accurately forecasting NPC. 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.

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[17] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-080220, Order 05, ¶ 26 (Oct. 8, 2008).
[18] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-050684, Order 04, ¶ 91 (Apr. 17, 2006).
[19] Docket UE-130043, Exhibit No.___(GND-1CT) at 36:21-22.

Q. Please describe the changes to wind resources in PacifiCorp's west control area generation portfolio since 2006.

A. Since 2006, PacifiCorp has added approximately 405 MW of new wind resources (Leaning Juniper, Goodnoe Hills, Marengo I and Marengo II) and 74 MW[20] of wind PPAs in the west control area. In total, the company now has 521 MW of owned and contracted wind resources used to serve load in west control area.

Q. Beyond system balancing issues, do intermittent renewable resources cause other impacts to PacifiCorp'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.

Q. Has the Company measured the variance between actual and forecast wind generation levels in its Washington NPC since enactment of the EIA?

A. Yes. The Company measured the change in the net market value of PacifiCorp's owned wind generation from 2007 to 2012, using actual and forecast wind generation levels and market prices. As shown in Table 7 below, the combined impact of variances in wind generation, market prices, and PTCs over the historical period ranges from $0.2 million to $12.2 million of over-forecast value annually on a Washington-allocated basis, or a cumulative total of $34.8 million. Because the

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[20] The 74 MW of wind PPAs is comprised of ten QF PPAs located in Oregon.

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

Table 7

Changes in Wind Value 2007 - 2012

	2007	2008	2009	2010	2011	2012	Cumulative Total
GRC Forecast							
Wind Generation (MWh)	255,152	364,357	824,814	1,289,989	1,273,395	1,267,568	5,275,275
Market Price ($/MWh)	57.03	55.25	49.69	56.60	44.90	33.59	47.09
Market Value ($m)	14.6	20.1	41.0	73.0	57.2	42.6	248.4
Less: PPA Cost ($m)	3.5	3.7	4.6	4.1	4.5	5.0	25.2
Net Market Value ($m)	11.1	16.5	36.4	68.9	52.7	37.6	223.2
Actual							
Wind Generation (MWh)	252,374	391,548	838,119	1,036,912	1,190,573	1,057,002	4,766,529
Market Price ($/MWh)	43.96	50.58	25.89	26.69	17.56	12.74	24.05
Market Value ($m)	11.1	19.8	21.7	27.7	20.9	13.5	114.6
Less: PPA Cost ($m)	4.1	4.9	3.6	3.7	4.8	4.9	26.0
Net Market Value ($m)	7.0	14.9	18.1	24.0	16.1	8.5	88.6
Forecast Variance							
Wind Generation (MWh)	(2,778)	27,191	13,305	(253,076)	(82,822)	(210,566)	(508,746)
Market Price ($/MWh)	(13.07)	(4.66)	(23.80)	(29.91)	(27.34)	(20.86)	(23.04)
Market Value ($m)	(3.5)	(0.3)	(19.3)	(45.3)	(36.3)	(29.1)	(133.8)
Less: PPA Cost ($m)	0.6	1.2	(1.0)	(0.4)	0.3	(0.1)	0.8
Net Market Value ($m)	(4.1)	(1.5)	(18.3)	(44.9)	(36.6)	(29.1)	(134.6)
PTC Increase/(Reduction) ($m)	(0.4)	0.7	0.9	(8.2)	(2.9)	(7.0)	(16.9)
Total ($m)	(4.4)	(0.8)	(17.5)	(53.1)	(39.5)	(36.1)	(151.5)
WA Allocated Total ($m)	(1.0)	(0.2)	(4.0)	(12.2)	(9.1)	(8.3)	(34.8)

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 PacifiCorp's dispatchable resources on a moment-to-moment basis. The addition of wind has dramatically changed the way PacifiCorp 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 more complex operating environment for PacifiCorp 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. Does the Company's GRID model capture the uncertainty of wind generation?

A. No. GRID models wind generation and market prices using a static forecast. Because wind generation and market prices vary every hour of the year, it is certain that actual wind output will vary from the GRID forecast, even with the modeling improvements implemented in this case. The RRTM will ensure that this component of the cost to comply with the EIA is appropriately reflected in customers' rates.

Q. Will the RRTM include recovery of fixed costs related to wind generation (*i.e.*, capital investment in rate base)?

A. No. The RRTM will address only the value of the wind energy and will not include any recovery of capital investment.

Q. Is PacifiCorp addressing recovery of RPS-related costs in any other states?

A. Yes. On June 19, 2013, PacifiCorp, together with Portland General Electric Company (PGE), asked the Public Utility Commission of Oregon to establish a generic docket to examine policies and design of PCAMs. After communicating with interested parties in Oregon, PacifiCorp and PGE narrowed the scope of the request to include a review of the ratemaking treatment of variable RPS compliance costs only.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.