Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("the Company").

A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. I am a Certified Public Accountant licensed in the state of Utah. Prior to joining the Company, I was employed as an internal auditor for Intermountain Healthcare and as an auditor for the Utah State Tax Commission. I have been employed by the Company since February 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in Wyoming, Idaho, California, and Oregon.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents and supports the Company's calculation of the Energy Balancing Account ("EBA") deferral for the 12-month period from January 1, 2015, through December 31, 2015 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $18.9 million for excess EBA-related costs, including interest and the Utah-allocated Deer Creek amortization expense; and,
- A discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC").

EBA Deferral Calculation

Q. Please describe the Company's calculation of the EBA deferral for the Deferral Period.

A. The Company's application requests recovery of $18.9 million comprised of $11.3 million for deferral of excess EBA-related costs, a credit of $2.8 million for coal fuel expense savings related to the Deer Creek mine closure and not subject to the sharing band, $1.3 million of interest, and $9 million for the Utah-allocated Deer Creek mine amortization expense. The excess EBA-related costs of $11.3 million are calculated as the difference between the Actual NPC and wheeling revenue and the Base NPC and wheeling revenue, as established in Docket No. 13-035-184 ("2014 GRC"), then applying the 70 percent sharing band to that difference. The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

$$EBA\ Deferral_{Utah,month} =$$

$$\left[\left(Actual\ EBAC\frac{Utah,month}{MWh} - Base\ EBAC\ \frac{Utah,month}{MWh}\right) \times\ Actual\ MWh_{Utah,month}\right] \text{ x } 70\%$$

Exhibit RMP___(MGW-1) presents the detailed calculation of the EBA deferral on a monthly basis during the Deferral Period, and Table 1 below provides a breakdown of the total EBA recovery.

Table 1
Annual EBA Calculation

Calendar Year 2015 EBA Deferral			*Exhibit RMP___(MGW-1) Reference*
Actual EBAC ($/MWh)	$	25.99	*Line 5*
Base EBAC ($/MWh)	$	25.31	*Line 10*
$/MWh Differential	**$**	**0.68**	
Utah Sales (MWh)		24,127,542	*Line 4*
EBA Deferrable*	$	16,157,578	*Line 12*
EBA Deferral at 70% Sharing	$	11,310,305	*Line 13*
Coal Fuel Savings not Subject to Sharing*	$	(2,787,700)	*Line 14*
Total Deferrable	$	8,522,604	*Line 15*
Interest Accrued through December 31, 2015	$	405,032	*Line 19*
Interest Jan. 1, 2016 through Oct. 31, 2016	$	921,872	*Line 22*
Deer Creek Amortization Costs	$	9,098,764	*Line 21*
Requested EBA Recovery	**$**	**18,948,273**	*Line 23*

** Calculated monthly*

Q. What revenue requirement components are included in the EBA deferral calculation?

A. The EBA deferral calculation consists of two revenue requirement components, NPC and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. Wheeling revenue includes amounts booked to FERC account 456.1, revenues from transmission of electricity of others. Collectively these two components are known in the Company's EBA tariff, Schedule No. 94, as Energy Balancing Account Costs ("EBAC").

Per the stipulation in Docket No. 14-035-147 ("Deer Creek Settlement"), the EBA includes 100 percent of the Utah-allocated amortization expense associated with the closure of the Deer Creek mine. Additionally, 100 percent of the Utah-allocated coal fuel expense savings at the Hunter and Huntington plants related to the closure of the Deer Creek mine are passed through to customers. The separate treatment of the Deer Creek amortization expense and the coal fuel expense savings will continue to be part of the EBA until they are included in base rates.

Q. How are the Utah-allocated Actual NPC calculated?

A. Utah-allocated Actual NPC are calculated in three steps. First, unadjusted actual NPC are established on a total-company basis. Second, adjustments are made to the unadjusted actual NPC to apply certain regulatory adjustments and to remove out-of-period accounting entries. Third, the adjusted total-company Actual NPC are allocated to Utah on the basis of the 2010 Protocol.

Q. What were the total-company adjusted Actual NPC for the Deferral Period and how were they determined?

A. The total-company adjusted Actual NPC in the Deferral Period were approximately $1.537 billion. This amount captures all components of NPC as defined in the Company's general rate case proceedings and modeled by the Company's Generation and Regulation Initiative Decision Tool ("GRID") model. Specifically, it includes amounts 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[1] (gas and 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 the Bonneville Power Administration ("BPA") residential exchange credit pass-through if applicable
Account 565 -	Transmission of electricity by others

During 2015, several new SAP accounts were used in the Company's accounting system to track components of NPC and wheeling revenue. Specifically, new SAP accounts were established to track fuel expenses and NPC-related accounting entries arising from participation in the energy imbalance market ("EIM") with the California Independent System Operator ("CAISO"). These accounts fall within the main FERC accounts that make up the EBAC, but the specific SAP accounts are not identified in the current Schedule 94. Exhibit RMP___(MGW-2) identifies the new accounts used in 2015. The new accounts are also included in the revised tariff sheets provided in the testimony of Ms. Joelle R. Steward.

Q. What adjustments are made to Actual NPC and why are they needed?

[1] Start-up fuel is accounted for separately 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.

A. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items, including buy-through of economic curtailment by interruptible industrial customers, situs assignment of the generation from Oregon solar resources procured to satisfy ORS 757.370 solar capacity standard, revenue associated with a unique contract for the Company's Leaning Juniper facility, coal inventory adjustments to reflect coal costs in the correct period, and legal fees related to fines and citations included in the cost of coal. The Company also adjusts Actual NPC to remove accounting entries booked in the Deferral Period that related to operations prior to implementation of the EBA in October 2011. During the Deferral Period the Company returned energy to a third party to compensate for prior excess line losses charged to the third party by the Company. An adjustment was made to Actual NPC to match the expense of returning energy with the period the energy was returned, and to exclude the portion of returned energy associated with periods prior to the start of the EBA in October 2011. Additional details regarding each of these adjustments and the impact on NPC is provided in Additional Filing Requirement 15.

Q. What allocation methodology did the Company use to calculate the EBA Deferral Account balance?

A. The settlement stipulation in the 2014 GRC set the Base NPC effective September 1, 2014 using the Commission Order Method which was originally approved by the Commission in Docket No. 09-035-15. The Base NPC and Commission Order Method were detailed in the Exhibit A of the stipulation in the 2014 GRC. Attached

Exhibit RMP___(MGW-1) calculates the EBA deferral using the Commission Order Method for the entire Deferral Period.

Q. Has the Company calculated the EBA deferral using any other allocation methods?

A. No. Consistent with the stipulation in the 2014 GRC, beginning September 2014 only the Commission Order Method is used.

Q. Does the calculation of the EBA deferral include carrying charges?

A. Yes. In accordance with the Commission's March 2, 2011 order in Docket No. 09-035-15 and January 20, 2016 order in Docket No. 15-035-69, carrying charges accrue on the monthly EBA deferral at an annual rate of six percent. Carrying charges accrue monthly during the Deferral Period, the review period, and will continue to accumulate during the collection period.

Deferral Period Results

Q. Please describe the Base EBAC the Company used to calculate the amount to be deferred during the Deferral Period.

A. The Base EBAC for the 2015 EBA was set in the 2014 GRC and includes a step change effective September 1, 2015. Step 1 and Step 2 Base NPC were both set in the 2014 GRC, and Step 2 includes an adjustment to effectuate the step change. Throughout my testimony I refer to the two bases together as the Base EBAC. The 2014 GRC used a test period of 12 months from July 2014 through June 2015. Step 1 set total-company Base NPC at $1.495 billion and wheeling revenue at $97 million, and Step 2 set total-company Base NPC at $1.491 billion and maintained wheeling revenue at $97 million. The combined total-company Base NPC for both steps is $1.494 billion and wheeling revenue is $97 million.

Q. Please describe Table 2 and the line items making up the difference between Actual NPC and Base NPC.

A. Table 2 displays the Base NPC approved by the Commission for the Deferral Period. The remainder of Table 2 is a breakout of the difference between Actual NPC and Base NPC, by cost category, on a total-company basis. The differences by category in Table 2 result from comparing Actual NPC to the Base NPC effective during the Deferral Period.

Table 2

Total Company Net Power Cost Reconciliation ($millions)

		TOTAL
Combined Base NPC	**$**	**1,494**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		133
Purchased Power Expense		(41)
Coal Fuel Expense		(46)
Natural Gas Expense		(1)
Wheeling and Other Expense		(3)
Total Increase/(Decrease)	**$**	**43**
Adjusted Actual NPC	**$**	**1,537**

Q. Is the Deferral Period aligned with the test period used in the 2014 GRC?

A. No. The 2014 GRC test period (July 2014 through June 2015) used to set the Base EBAC does not align with the Deferral Period. To calculate the EBA deferral, the months in the deferral period are compared to the same months from Base NPC in effect at the time. As a result, in this EBA filing, July 2015 Actual NPC is compared against July 2014 Base NPC to calculate the deferrable amount. Actual NPC is compared to a forecast that is one year out of sync for the months of July through December.

Q. Has the misalignment of Base NPC test periods been an issue in past EBA filings?

A. Yes. This same issue has been a factor in each of the Company's last two EBA filings. The Division addressed this in its Preliminary Evaluation of PacifiCorp's EBA Pilot Program report filed with the Commission on May 22, 2014.[2] The Division noted that it "considers the mismatch in months to be the greatest concern in the current EBA structure."[3]

Differences in NPC

Q. Notwithstanding the issues of test period timing, please describe the primary differences between Actual NPC and Base NPC.

A. From an accounting perspective, and as shown in Table 2, Actual NPC were higher than Base NPC due to a $133 million reduction in wholesale sales revenues. This was partially offset by a $41 million reduction in purchased power expense, $46 million reduction in coal fuel expense and a $1 million reduction in natural gas expense. Actual NPC were also higher than Base NPC due to a reduction in zero-fuel-cost generation from the Company's owned hydro and wind resources.

Q. Please quantify the reduction in Company-owned wind and hydro resources that caused an increase in NPC.

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[2] Preliminary Evaluation of PacifiCorp's EBA Pilot Program, May 22, 2014, Docket No. 09-035-15, pages 31-32.
[3] Id.

A. Actual generation from Company-owned hydro and wind resources was 1,022 GWh (26 percent) and 576 GWh (18 percent) lower than projected in Base NPC, respectively, negatively impacting NPC by more than $48 million. Generation from hydro and wind facilities is a zero fuel cost resource and decreased generation from wind and hydro must be replaced with either additional generation from the Company's thermal resources or power procured from the wholesale market, both of which increase NPC. Additionally, significant decreases in wind and hydro generation load can limit the Company's ability to sell economic generation into wholesale markets. If Company-owned hydro and wind generation would have been near the normal levels projected in Base NPC, Actual NPC would have been lower.

Q. Please explain what contributed to the reduction in wholesale sales revenue.

A. The decline in wholesale sales revenues relative to Base NPC was a combination of a reduction in the wholesale sales volumes of market transactions (represented in GRID as short-term firm and system balancing sales) and lower market prices

Revenue from market transactions is approximately $115 million lower than Base NPC due to a lower volume of market sales transactions and lower market prices - actual wholesale market sales volumes were 812 GWh, or 10 percent, lower than the Base NPC. The reduced volume is driven in part by the significantly lower output from hydro and wind resources. The average price of actual market sales transactions was $10.96/MWh (28 percent) lower than the average price in Base NPC.

Additionally, long-term wholesale sales contracts with Shell and Sacramento Municipal Utility District ("SMUD") were included in Base NPC but have since expired. Expiration of these contracts accounted for $15 million reduction in wholesale sales revenue and a 524 GWh reduction in sales volume.

Q. Please explain the decrease in purchased power expenses.

A. The reduction in purchased power expense was largely due to a decrease of $43 million in long-term purchase power contracts. The Hermiston purchase power agreement ("PPA") accounted for $20 million of the reduction. Per the Hermiston PPA, the Company purchases the natural gas used for generation, and reductions in natural gas market prices resulted in decreased purchase power expense. Additionally, many of the Company's long-term contracts are with wind generators which generated less than the projected volume included in Base NPC. The decrease was partially offset by six qualifying facilities ("QFs") that were not included in Base NPC and a PPA with Utah Associated Municipal Power Systems ("UAMPS") the Company acquired with its addition of Eagle Mountain, Utah into its service territory.

Expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) partially offset the reduction of purchased power costs. Actual market purchases are approximately $3 million higher than Base NPC. However, actual market purchases were 275 GWh (six percent) lower than Base NPC. The impact of lower purchase volumes is offset by higher actual market prices for market purchases - the average actual purchase price was $2.34/MWh higher than in Base NPC.

Q. Please discuss the changes in coal fuel expense.

A. The main driver in the decrease of coal fuel expense is that coal generation volume decreased 1,341 GWh (three percent) compared to Base NPC. The average cost of coal generation also decreased from $19.77/MWh in Base NPC to $19.30/MWh in the Deferral Period, contributing to an overall decrease of $46 million in coal fuel expense.

Q. Please describe the changes in natural gas fuel expense.

A. The total natural gas fuel expense in Actual NPC remains relatively level as it only slightly decreased by less than $1 million compared to the Base NPC. The average cost of natural gas generation decreased from $39.73/MWh in Base NPC to $30.21/MWh (24 percent) in the Deferral Period. Reduced costs were offset by an increase in natural gas generation volume of 2,197 GWh (31 percent) above Base NPC during the Deferral Period.

Q. Are the actual benefits from participating in the EIM with CAISO included in the EBA deferral?

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. Financially binding EIM operation went live November 1, 2014, and all net benefits arising from EIM operation from January 1, 2015 to December 31, 2015, are included in the EBA deferral.

Q. Have the benefits realized during 2015 been quantified?

A. Yes. CAISO published quarterly reports ("CAISO Reports") estimating the benefits realized through EIM operation. The CAISO Reports estimated benefits attributable to PacifiCorp of approximately $26.2 million on a total-company basis for the deferral period. The benefits estimated for PacifiCorp in the CAISO Reports include the benefits of EIM operation due to more efficient dispatch (both inter- and intra-regional) and reduced flexibility reserves.

Q. Does this conclude your direct testimony?

A. Yes.