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

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003 including positions in revenue requirement and regulatory affairs, and I assumed my current role managing the Company's net power cost group in March 2012.

Q. Have you testified in previous regulatory proceedings?

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

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, 2014, through December 31, 2014 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $30.5

million for excess EBA-related costs, including interest; and,

- A discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC").

Throughout my testimony I describe how the Company has complied with settlement stipulations and Commission orders from previous cases, including the settlement agreement reached in the Company's most recent EBA filing in Docket No. 14-035-31 ("2014 EBA").

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 $30.5 million, comprised of $29.0 million deferral of excess EBA-related costs, a credit of $1.2 million to true up incremental wheeling revenue as a result of the Federal Energy Regulatory Commission ("FERC") rate case (Docket No. ER11-3643-000), and $2.6 million of interest. The excess EBA-related costs of $29.0 million are calculated by finding the difference between the Actual NPC and wheeling revenue and the Base NPC and wheeling revenue which were established in Docket No. 11-035-200 ("2012 GRC") and 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___(BSD-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

Calendar Year 2014 EBA Deferral			Exhibit RMP___(BSD-1) Reference
Actual EBAC ($/MWh)		$ 27.10	*Line 11*
Base EBAC ($/MWh)		$ 25.38	*Line 16*
$/MWh Differential		**$ 1.72**	
Utah Sales (MWh)		24,089,061	*Line 10*
Total Deferrable*	$	41,477,596	*Line 18*
EBA Deferral at 70% Sharing	$	29,034,318	*Line 19*
Additional FERC ER11-3643 Revenues	$	(1,204,554)	*Line 20*
Interest Accrued through December 31, 2014	$	1,159,202	*Line 25*
Interest Jan. 1, 2015 through Oct. 31, 2015	$	1,482,500	*Line 27*
Requested EBA Recovery	**$**	**30,471,465**	*Line 28*

**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 as Energy Balancing Account Costs ("EBAC").

During 2014 several new SAP accounts were used in the Company's accounting system to track components of net power costs and wheeling revenue.

Specifically, new SAP accounts were established to track inter-company transactions with Nevada Power and Sierra Pacific (now affiliates of PacifiCorp), and to track 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___(BSD-6) identifies the new accounts used in 2014. 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 these adjustments needed?

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 cost 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. Additional details regarding each of these adjustments and the impact on NPC is provided in Additional Filing Requirement 15.

Q. Were there any adjustments made to Actual NPC that are new in this filing?

A. Yes. 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. Consistent with the settlement agreements resolving the Company's past two general rate cases, two allocation methodologies were required to calculate the Actual EBAC, Base EBAC, and the resulting EBA deferral in this application. The stipulated Scalar Method was used to calculate the EBA deferral for the period of January - August 2014, and the Commission Order Method was used to calculate the EBA deferral for the period of September - December 2014. Exhibit RMP___(BSD-1) calculates the EBA for the entire Deferral Period using each method in its respective months.

The Scalar Method was originally developed as part of the settlement agreement reached in Docket No. 10-035-124 ("2011 GRC") and the same approach was again adopted in the settlement resolving the 2012 GRC. In the 2012 GRC settlement the Scalar Method was detailed in Exhibit A1: "Utah Allocation Based on Scalar Method from Docket 10-035-124".

The settlement stipulation in the 2014 GRC no longer utilized the Scalar Method, but 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. Exhibit RMP___(BSD-2), attached to my testimony, shows the EBA calculation using the Commission Order Method for the entire Deferral Period enabling a comparison to the Scalar Method through August 2014. In its February 19, 2015, order in Docket Nos. 09-35-15/14-035-31 the Commission directed the Utah Division of Public Utilities ("the Division") to include such a comparison of the Scalar Method and Commission Order Method in its final EBA evaluation report in 2016.

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

A. Yes. For the period January through August 2014, the Company calculated the EBA deferral under the Scalar Method, and the A2 and A3 Methods utilized in the 2012 GRC settlement. Exhibit RMP___(BSD-3), Exhibit RMP___(BSD-4), and Exhibit RMP___(BSD-5) separately provide the EBA calculation using the Scalar Method, A2 Method, and A3 Method, respectively. Consistent with the stipulated agreement in the 2014 GRC, beginning in 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, carrying charges accrue on the monthly EBA deferral at an annual rate of six percent. Carrying charges accrue monthly during the Deferral 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 2014 EBA has a split Base EBAC during the Deferral Period. The period of January 1, 2014, through August 31, 2014, has a Base EBAC set in the 2012 GRC. The period of September 1, 2014 through December 31, 2014, has a Base EBAC set in the 2014 GRC. Throughout my testimony I refer to the two bases together as the Base EBAC. The 2012 GRC used a test period of the 12 months from June 2012 through May 2013 and set total Company Base NPC at $1.479 billion and total Company wheeling revenue at $74.7 million. The 2014 GRC used a test period of the 12 months from July 2014 through June 2015 and set total Company Base NPC at $1.496 billion and total Company wheeling revenue at $96.5 million. The combined Base NPC is $1.483 billion and total Company wheeling revenue is $82 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)

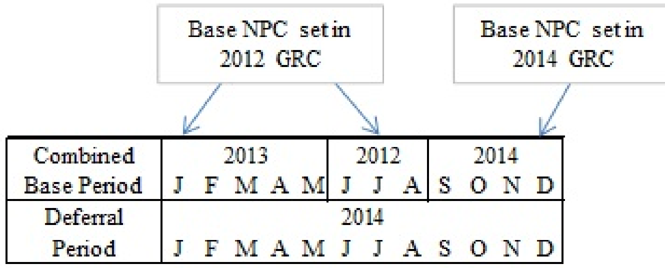
		TOTAL
Combined Base NPC	$	1,483
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		57
Purchased Power Expense		(53)
Coal Fuel Expense		35
Natural Gas Expense		69
Wheeling and Other Expense		8
Total Increase/(Decrease)	$	117
Adjusted Actual NPC	$	1,600

Q. Is the Deferral Period aligned with the test period used in the 2012 GRC to determine the Base EBAC from January 1, 2014 through August 31, 2014?

A. No. The 2012 GRC test period (June 2012 through May 2013) used to set the Base EBAC does not align with the Deferral Period because Base EBAC from that case were in rates from January 1, 2014, through August 31, 2014. 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 2014 Actual NPC is compared against July 2012 Base NPC to calculate the deferrable amount. In fact, prior to re-setting Base NPC effective September 1 2014, Actual NPC is compared to a forecast that is one or two years out of sync, depending on the month.

The mismatch between the Base NPC test period and the Deferral Period creates a distinct division during 2014: 1) January 2014 through August 2014, when Base NPC from the 2012 GRC does not align with the corresponding months, and 2) September 2014 through December 2014, when the months from Actual NPC align to the corresponding months in the 2014 GRC test period. Figure 1 below illustrates how the months line up between the Base NPC and the Deferral Period.

Figure 1



Q. How do the mismatched periods impact the EBA deferral?

A. Table 3, below, demonstrates the difference between Actual NPC and Base NPC for the two distinct periods during the Deferral Period. The table shows that over 95 percent of excess NPC in 2014 occurred between January and August when the periods were not properly matched.

Table 3
Total Company Net Power Cost Reconciliation ($millions)
Mismatched Test Periods

	Jan- Aug	Sep - Dec	TOTAL
Base NPC	$ 1,000	$ 482	$ 1,483
Increase/(Decrease) to NPC:			
Wholesale Sales Revenue	40	18	57
Purchased Power Expense	(23)	(29)	(53)
Coal Fuel Expense	50	(15)	35
Natural Gas Expense	38	32	69
Wheeling and Other Expense	8	1	8
Total Increase/(Decrease)	**$ 112**	**$ 5**	**$ 117**
Adjusted Actual NPC	**$ 1,112**	**$ 488**	**$ 1,600**

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.[1] The Division noted that it expected the potential for "more extreme variation to continue from January 2014 through August 2014 due to the fact that base NPC will not be 'reset' into rates until the beginning of September 2014" and went on to state that it "considers the mismatch in months to be the greatest concern in the current EBA structure."[2] The Company looks forward to addressing this issue when changes to the EBA will be considered at the end of the pilot program.

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 $57 million reduction in wholesale sales revenues, a $35 million increase in coal fuel expense and a $69 million increase in natural gas expense. These increases in NPC were partially offset by a $53 million reduction in purchase power expenses. Actual NPC were also higher than Base NPC due, in part, to an increase in system load and a reduction in zero-fuel-cost generation from the Company's owned hydro and wind resources.

Q. Please explain the changes in load and resources that caused an increase in NPC.

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

A. Net system load was 787 GWh higher than forecasted load used in the Base NPC. Furthermore, actual generation from Company owned hydro and wind resources was 139 GWh and 188 GWh lower than projected in Base NPC, respectively. Higher load increases NPC because the Company must purchase or generate electricity to serve the load, and may be unable to sell economic generation into wholesale markets. Generation from hydro and wind facilities is a zero cost resource and must be replaced with additional generation from the Company's thermal resources or a net increase in power procured from the wholesale market, also increasing NPC. Consequently, variances in load and hydro and wind generation impact several of the cost categories shown in Table 2.

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 the Company's production dispatch model ("GRID") as short-term firm and system balancing sales) and a reduction in realized prices of market transactions. Actual wholesale market sales volumes were 1,464 GWh, or 15 percent, lower than the Base NPC largely driven by the 1,055 GWh shorter position resulting from higher loads and lower output from hydro and wind resources. The average realized price for market sales transactions was $33.04 per MWh in Actual NPC compared to $34.14 per MWh in Base NPC.

Q. Please explain the decrease in purchased power expenses.

A. Actual purchased power volumes were lower than the level included in Base NPC, mainly related to wholesale market transaction volumes. In total, actual wholesale market purchase expense was $49.8 million lower than the amount in Base NPC. Compared to the Base NPC, wholesale market purchase transaction volume decreased by 3,712 GWh, or 60 percent, largely driven by increased generation from the Company's natural gas-fired facilities as described later in my testimony. The impact of lower purchase volumes is partially offset by higher realized prices for market purchases - the average actual purchase price was $18.68 per MWh higher than in Base NPC.

Q. Were there specific contract changes that impacted purchase power expense?

A. Yes. The Base NPC set in the 2012 GRC contained several long-term power purchase contracts that were not included in the Deferral Period, including a purchase contract with Grant County Public Utility District, a Kennecott generation incentive, and a purchase contract for the output of the West Valley generating station. The expiration of these contracts accounts for a reduction of approximately $9.9 million in purchased power expense. In addition, expenses were $4.8 million lower because two customers used their on-site qualifying facility ("QF") generation to serve their own load, and $5.2 million lower because one QF contract included in the forecast did not reach commercial operation during the Deferral Period.

The reduction in purchased power expense due to expired contracts was partially offset by a new seasonal purchase power contract (which was not included in the 2012 GRC but was in the 2014 GRC) entered into with Constellation Energy, increasing expenses $3.7 million compared to Base NPC, and several new QF contracts, increasing expenses $3.2 million.

Q. Please discuss the changes in coal fuel expense.

A. Coal fuel expense was $34.9 million higher than the Base NPC, mainly due to an increase in actual prices for coal compared to prices included in Base NPC. Total coal generation output was within approximately 600 GWh, an increase of 1.4 percent. Notably, the higher coal prices occurred during the misaligned months of January through August. These eight months accounted for $50.2 million of higher coal fuel expenses, which was partially offset by a $15.3 million reduction in coal fuel expenses from September to December 2014. The average actual cost of coal generation from January to August was $1.27/MWh higher than in Base NPC, increasing coal costs from $17.84/MWh in Base NPC set in the 2012 GRC to $19.10/MWh. Since the 2012 GRC there have been some notable changes that have affected coal fuel costs including contractual coal price increases, new coal contracts, and increased mine operating costs at the Bridger and Deer Creek mines.

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

A. The total natural gas fuel expense in Actual NPC increased by $69.3 million compared to the Base NPC. This difference is a result of an increase in natural gas generation volume of 2,682 GWh, or 33 percent, above Base NPC. The Lake Side 2 combined cycle combustion turbine plant reached commercial operation during the Deferral Period, and was not included in the 2012 GRC, increasing gas generation approximately 724 GWh. The remaining increase in natural gas generation volume occurred mainly at the Company's Lake Side 1, Currant Creek, and Chehalis plants. All three plants generated more due to more periods with favorable economics (i.e. lower market prices for natural gas relative to electricity) in the Deferral Period compared to the Base NPC. The actual average cost of natural gas generation was 9 percent lower than in Base NPC, dropping from $41.61/MWh to $37.72/MWh. In addition, starting in December 2013, the Chehalis plant was moved into the Company's balancing authority area and was able to provide reserves during the Deferral Period, causing it to be operated more than previously modeled in GRID (in the 2012 GRC) where it was not able to provide reserves.

Q. Are the actual benefits from participating in the EIM 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 through December 31, 2014, are included in the EBA deferral.

Q. Has the amount of benefits realized during November and December 2014 been quantified?

A. On February 11, 2015, the CAISO published the first quarterly report ("CAISO Report") estimating the benefits realized through EIM operation in November and December 2014. The CAISO Report estimated benefits attributable to PacifiCorp of approximately $4.72 million on a total-company basis for the two-month period. The CAISO Report quantified the estimated gross benefits from the first two months of EIM operation due to more efficient dispatch (both inter- and intra-regional) and reduced renewable energy curtailment (applicable to CAISO).

Benefits from reduced flexibility reserves were not yet calculated, but the CAISO indicated it anticipates adding that calculation to future reports.

Compliance with 2014 EBA Settlement Stipulation

Q. What did the Company agree to do in the 2014 EBA settlement stipulation?

A. In the stipulation agreement approved by the Commission to resolve the 2014 EBA, the Company made thirteen separate commitments intended to improve the EBA process and facilitate the Division's audit of the Company's filings. The Company agreed to do the following:

- Implement a process to contemporaneously document a trade purpose for all hedging transactions.
- Provide a narrative documenting the trade purpose for trades that deviate from the strategy and objectives set forth in the Commercial Objectives report.
- Seek to obtain permission to provide industrial customer billing information related to curtailment buy-through in advance of the EBA.
- Provide a contact at the Intercontinental Exchange ("ICE") and to coordinate requests for ICE data.
- Allow the Division to request trade information outside of a formal EBA request and provide the requested information if available.
- Continue to provide trade data on a quarterly basis and annually in advance of the filing (Filing Requirement 6(b)).
- Establish a comprehensive list of documents, policies, and reports used or relied on by traders in trading activity, including a description of how the information is generally used.

- Answer all data requests timely and raise any potential issues with data requests as soon as practicable.
- Make Company personnel available in person or by phone to review relevant material with the Division as needed.
- Meet in person with the Division to discuss trades selected by the Division as its sample for review along with any relevant data, documents, policies and reports concerning those trades.
- File a notice of the impending EBA application annually on January 15.
- Record the competitive price for non-brokered transactions beginning November 1, 2014.
- Inform the Division of updates to policies affecting hedging and a detailed explanation of the reason(s) for the update.

Q. Is the Company in compliance with the 2014 EBA settlement stipulation?

A. Yes. The Company has completed all commitments with discrete deliverables, and will continue to meet commitments with ongoing obligations. The Company expects that following through with the 2014 EBA commitments will serve to improve the EBA process and facilitate the Division's review in this filing and in future EBA filings.

Q. Have the Division and the Commission acknowledged the Company's completion or ongoing fulfillment of the settlement stipulation in the 2014 EBA?

A. Yes. The Division filed a memorandum on January 22, 2015, recommending the Commission acknowledge the Company's completion or ongoing fulfillment of these commitments, and the Commission did so in its order issued February 19, 2015.

Q. Does this conclude your direct testimony?

A. Yes.