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 Manager, 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 the Company's calculation of the Energy Balancing Account ("EBA") deferral for the 12-month period from January 1, 2013, through December 31, 2013 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $28.3 million for the Deferral Period; 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 outcome of Docket No. 13-035-32 (“2013 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 $28.3 million for the Deferral Period, comprised of $27.6 million deferral of excess EBA-related costs, a credit of $1.1 million to true-up incremental wheeling revenue due to the recently completed Federal Energy Regulatory Commission (“FERC”) rate case (Docket No. ER11-3643-000), and $1.8 million of interest. Exhibit RMP___(BSD-1) presents the detailed calculation of the EBA deferral on a monthly basis during the Deferral Period. Table 1 below provides a breakdown of the total requested EBA recovery.

Table 1
Summary of EBA Deferral Account Balance

Calendar Year 2013 EBA Deferral	
Actual EBAC ($/MWh)	$ 27.04
Base EBAC ($/MWh)	$ 25.44
$/MWh Differential	**$ 1.61**
Utah Load (MWh)	24,456,528
Total Deferrable*	$ 39,454,809
EBA Deferral at 70% Sharing	$ 27,618,366
Additional FERC ER11-3643 Revenues	($1,128,262)
Interest through Dec. 31, 2013	$ 470,671
Interest Jan. 1, 2014 through Oct. 31, 2014	$ 1,378,778
Requested EBA Recovery	**$ 28,339,553**

** 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 2013 several new SAP accounts were used in the Company's accounting system to track components of net power costs and wheeling revenue. These accounts fall within the main FERC accounts that make up EBAC, but the specific SAP accounts are not identified in the current Schedule 94. Exhibit RMP___(BSD-2) identifies the new accounts used in 2013. 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, and legal fees included in the cost of coal related to fines and citations. 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.

Q. Were there any new adjustments made to Actual NPC in the Deferral Period?

A. Yes. The Company received a small amount of revenue associated with the Company's Leaning Juniper facility due to a contract unique to that wind project. As a result of the contract, output at Leaning Juniper is now forecast at a slightly reduced level. This adjustment to the output of the Leaning Juniper wind project is consistent with the terms of stipulation, and a similar adjustment was made to the forecast NPC included in the Company's recently filed general rate case.

Q. What methodology did the Company use to calculate the EBA deferral

account balance?

A. The calculation of the Actual EBAC, Base EBAC, and the resulting EBA Deferral in this application is according to the stipulated Scalar Method. 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 Docket No. 11-035-200 ("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".

Generally, the EBA calculation is a comparison of actual NPC and wheeling revenue to the levels in rates as established in a general rate case, with 70 percent of the difference being deferred for later recovery or refund to customers. The calculation of the monthly amount debited or credited into the EBA Deferral Account using the Scalar Method is based on the following formula:

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

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

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

A. Yes. The Company calculated the EBA deferral under the various methods called for in the Commission's orders in Docket Nos. 12-035-67 and 09-035-15 as well as the 2012 GRC settlement. Company witness Mr. Steven R. McDougal provides the details of the illustrative EBA calculations in Exhibit RMP___(SRM-2) through Exhibit RMP___(SRM-4).

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

A. Yes. Consistent 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 continue to accumulate until rates are set to recover the approved EBA amount. Consistent with the Commission's order issued August 30, 2012, in Docket No. 12-035-67, et.al., the Company anticipates new rates will take effect November 1, 2014.

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

A. Base EBAC during the Deferral Period were determined in the 2012 GRC, which used a test period of the 12 months from June 2012 through May 2013. Total Company Base NPC were set at $1.479 billion, which was the level included in the Company's updated NPC filed in May 11, 2012. Total Company wheeling revenue was set at $74.7 million.

Q. What was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total Company basis, Actual NPC for the Deferral Period were approximately $1.620 billion, or approximately $140 million higher than the $1.479 billion Base NPC. Table 2 below summarizes the differences between Actual NPC and Base NPC.

Table 2
Total Company Net Power Cost Reconciliation ($millions)

			EBA Deferral Period
1	**Base NPC**	**$**	**1,479**
2	Increase/(Decrease) to NPC:		
3	Wholesale Sales Revenue		161
4	Purchased Power Expense		(21)
5	Coal Fuel Expense		46
6	Natural Gas Expense		(44)
7	Wheeling, Hydro and Other Expenses		(1)
8	**Total Increase/(Decrease)**		**140**
9	**Adjusted Actual NPC 2013**	**$**	**1,620**

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

A. Line one of Table 2 displays the approved Base NPC 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.

Q. Is the Deferral Period fully aligned with the test period used in the 2012 GRC to determine the Base EBAC?

A. No. The 2012 GRC test period (June 2012 through May 2013) used to set the Base EBAC is not fully aligned with the Deferral Period (January 2013 through December 2013). To calculate the EBA deferral, individual months are compared one with another. For example, July 2013 Actual NPC is compared against July 2012 Base NPC to calculate the deferrable amount.

The mismatch between the Base NPC test period and the Deferral Period creates a distinct division during 2013: 1) January 2013 through May 2013, when Base NPC from the 2012 GRC aligns with the corresponding months in the Actual NPC, and 2) June 2013 through December 2013, when the monthly comparison differs by one year.

Q. How does the misalignment of the two periods impact the deferral?

A. Table 3, below, illustrates the difference between Actual NPC and Base NPC for the two distinct periods during the Deferral Period. The table shows that the majority of the deferral occurred during the June through December time period when the mismatch in test year occurred. In fact, over 90 percent of excess net power costs in 2013 occurred during these seven months.

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

	Jan-May	Jun-Dec	Total
UT 2012 GRC Settlement	**$ 590**	**$ 889**	**$ 1,479**
Increase/(Decrease) to NPC:			
Wholesale Sales	23	138	161
Purchased Power	(18)	(3)	(21)
Coal Generation	5	41	46
Gas Generation	5	(49)	(44)
Wheeling Hydro and Other	(2)	1	(1)
Total Increase/(Decrease)	12	128	140
Adjusted Actual NPC 2013	**$ 602**	**$ 1,017**	**$ 1,620**

Q. Why is the EBA deferral $28.3 million or about 20 percent of the difference in total Company NPC of $140 million?

A. In addition to the difference between Actual NPC and Base NPC, the EBA deferral calculation is impacted by other items such as wheeling revenue, interjurisdictional allocation factors, sharing bands, and changes in retail sales volumes which impact the collection of Base NPC in rates. Table 4 provides an accounting of the EBA deferral separated into the net power cost and wheeling revenue components.

Table 4
Summary of EBA Deferral by Category

1	Utah Allocated Base NPC - Docket No. 11-035-200	$	636,001,721
2	Projected Utah Sales		23,734,643
3	NPC $/MWh (Line 1 / Line 2)	$	26.80
4	Actual Utah Sales (MWh)		24,456,528
5	Sales Adjusted Base NPC (Line 3 x Line 4)	$	655,125,999
6	Utah Allocated Actual NPC	$	697,427,372
7	**NPC Variance (Line 6 - Line 5)**	**$**	**42,301,372**
8	Utah Allocated Base Wheeling Revenue - Docket No. 11-035-200	$	(32,217,891)
9	Projected Utah Sales		23,734,643
10	Wheeling Revenue $/MWH (Line 8 / Line 9)	$	(1.36)
11	Actual Utah Sales		24,456,528
12	Sales Adjusted Base Wheeling Revenue (Line 10 x Line 11)	$	(33,177,057)
13	Utah Allocated Actual Wheeling Revenue	$	(36,023,620)
14	**Wheeling Revenue Variance (Line 13 - Line 12)**	**$**	**(2,846,563)**
15	**Total Deferrable EBAC (Line 7 + Line 14)**	**$**	**39,454,809**
16	EBA Deferral at 70% Sharing (Line 15 x 0.7%)	$	27,618,366
17	Additional FERC ER11-3643 Revenues	$	(1,128,262)
18	Interest through Dec. 31, 2013	$	470,671
19	Interest Jan. 1, 2014 through Oct. 31, 2014	$	1,378,778
20	**Requested EBA Recovery (Sum Lines 16 - 19)**	**$**	**28,339,553**

Table 4 shows that Utah sales in the Deferral Period were approximately 727 GWh higher than sales used to set the Base EBAC included in customers rates during 2013. Because actual sales were higher than forecast, the Company collected more to cover its costs during the Deferral Period, partially offsetting the increase in Utah-allocated Actual NPC. On Line 5 of Table 4, Base NPC is adjusted to account for the higher collections due to increased Utah sales. The increased sales help to offset the amount deferred in the EBA, resulting in a lower balance to be collected from customers later and preventing over- or under-collection of the variance in EBA costs.

Differences in NPC

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

A. Actual NPC were 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. From an accounting perspective, Actual NPC were higher than Base NPC due to a $161 million reduction in wholesale sales and $46 million increase in coal fuel expense. These increases in NPC were partially offset by a $21 million reduction in purchase power expenses and $44 million reduction in natural gas expense.

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

A. Net system load was over 1,500 GWh higher than forecasted load used in the 2012 GRC. Furthermore, actual generation from Company owned hydro and wind resources was 784 GWh and 127 GWh lower than projected in Base NPC, respectively. Higher load increases net power costs 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 net power costs. Consequently, variances in load and hydro and wind generation impact each of the cost categories shown in Table 1.

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

A. The primary contributor to the decline in wholesale sales revenues relative to the forecast base period was a reduction in the wholesale sales volumes, with much of the reduction related to short term sales made to balance the Company's system. Actual sales were 4,482 Gigawatt-hours (GWh), or 32 percent, lower than forecast sales of 13,875 GWh. Base NPC included 1,934 GWh of short term firm sales transactions (actual transactions included in the GRID model and executed in advance of the GRC filing) with deliveries between June 2012 and December 2012 which would not be relevant to the Deferral Period.

Q. Were there also specific long-term contract changes that caused a decrease in wholesale sales revenues?

A. Yes. Three long-term sales contracts with Nevada Energy, Pacific Gas & Electric, and Southern California Edison expired prior to the Deferral Period. The expiration of these contracts decreased wholesale sales by 986 GWh, or approximately $23 million.

Q. Please explain the decrease in purchased power expenses.

A. Similar to wholesale sales, actual purchased power volumes were lower than the level included in Base NPC, mainly related to short term purchases made to balance the Company's system. Overall, purchased power volume decreased by 3,382

GWh, or 22 percent, while the total purchased power expense decreased by $21 million, or three percent. Base NPC included 1,965 GWh of short term firm purchase transactions (actual transactions included in the GRID model and executed in advance of the GRC filing) with deliveries between June 2012 and December 2012 which would not be relevant to the Deferral Period. The reduction in total purchased power expenses due to lower volumes was muted due to an increase in the average market prices.

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

A. Yes. The long term power purchase contract with Grant County expired August 2012 and the Pioneer Wind Park II Qualify Facility ("QF") that was included in Base NPC never reached commercial operation. Removing these two contracts results in a decrease in NPC of $7 million compared to Base NPC. In addition, US Magnesium used its QF generation to serve its own load and the Company did not enter into a generation incentive agreement for 2013 with Kennecott Utah Copper LLC, resulting in a $5 million decrease in purchase power expense. A new seasonal purchase power contract was entered into with Constellation, increasing expenses $6 million compared to Base NPC.

Q. Please discuss the changes in coal fuel expense.

A. Coal fuel expense was $46 million higher than the forecast included in Base NPC, due to increased coal generation in actual operations. The volume of coal generation increased 2,515 GWh (six percent) while actual prices were within $0.02/MWh (0.13 percent).

Q. Do the higher wholesale market prices for electricity mentioned earlier impact the volume of coal generation?

A. Yes. All else held equal, wholesale electricity market prices impact the economics of the Company's generating units, such that if market prices are higher than the cost of generating electricity, the Company will operate those facilities during those hours. Figures 1 and 2 below show the change in average wholesale electricity prices during light load hours at the Mid Columbia and Palo Verde trading hubs, respectively, for the Deferral Period compared to the average price for coal generation. The lower market prices for electricity included in Base NPC caused reduced generation from the Company's coal fleet in the GRID model.

Figure 1
Coal vs. Electricity Market Prices – Mid Columbia

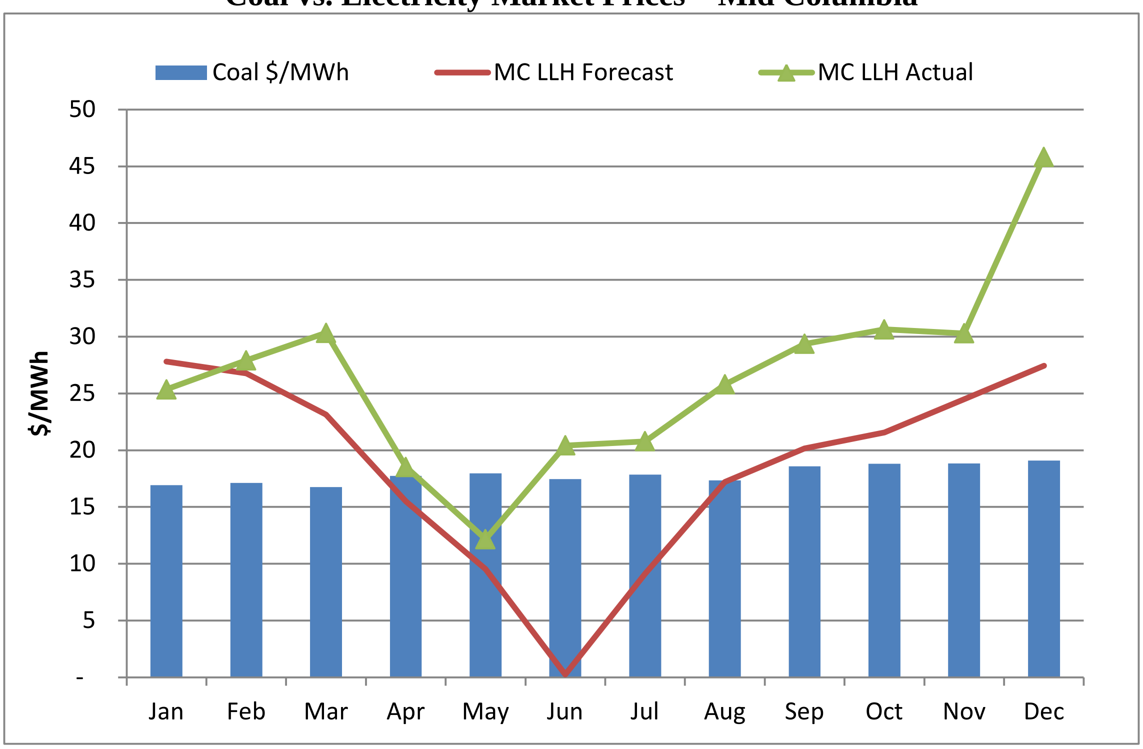
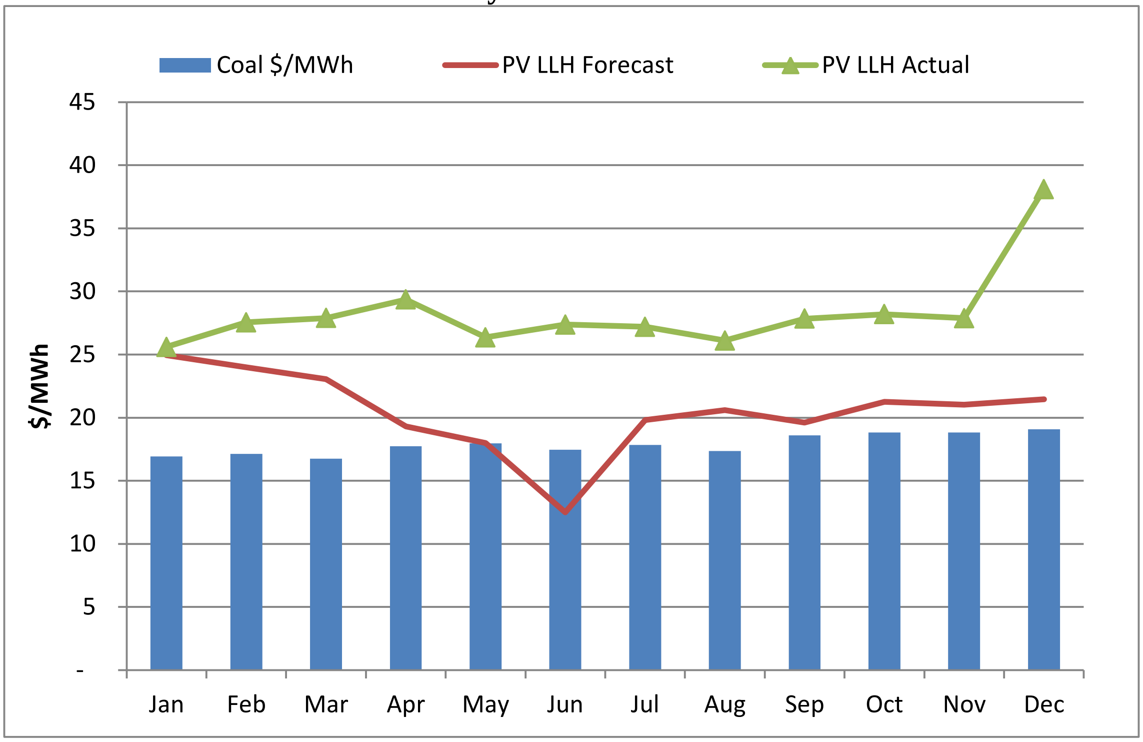


Figure 2
Coal vs. Electricity Market Prices – Palo Verde



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

A. The total natural gas fuel expense in Actual NPC decreased by $44 million compared to Base NPC. The decrease in natural gas fuel expense was due to a decrease in volume of 1,162 GWh in gas generation. Overall, the average price of natural gas fuel during the Deferral Period was one percent higher than the average price included in Base NPC.

Q. Did the Company utilize a "must-run" setting in the GRID model for specific gas units in the Base NPC?

A. Yes. Currant Creek and Gadsby CT were modeled as "must run" units to compute Base NPC in the 2012 GRC, setting them to operate at minimum capacity or higher during all hours of the test period. These two units accounted for over fifty percent of the decreased generation volume when comparing Base NPC versus Actual

NPC.

Compliance with Previous Orders

Q. Has the Company prepared this EBA filing in conformance with Commission orders in Docket No. 09-035-15 as well as the outcome of previous EBAs and general rate cases?

A. Yes. The Company's filing is in compliance with the Commission's order in Docket No. 09-035-15, and is consistent with applicable provisions of settlements reached in past EBA filings as well as the 2011 and 2012 GRCs. The Company's filing is accompanied by data as outlined in the filing requirements approved by the Commission in Docket No. 09-035-15 and augmented in Docket No. 12-035-67. Furthermore, the Company has continued to provide quarterly update filings to the Commission and the Division of Public Utilities reporting on the preliminary EBA balance and providing transactional data for electric and natural gas trades for each period.

Q. Did the Company participate in the technical conference to discuss dynamic allocation as called for in the stipulation resolving the 2013 EBA?

A. Yes. On February 26, 2014, the Company participated in the technical conference agreed to in Docket No. 13-035-32 to discuss the use of dynamic allocation factors in the EBA calculation. As described earlier in my testimony, Mr. McDougal's Exhibit RMP___(SRM-2) through Exhibit RMP___(SRM-4) provide illustrative examples of the EBA calculation under the various methods developed in past dockets in order for interested parties to consistently track the Company's annual filings and to view the impact of the various methods on the EBA deferral.

Q. Does this conclude your direct testimony?

A. Yes.