BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	**Docket No. 15-035-03**
Rocky Mountain Power to Decrease	**)**	
The Deferred EBA Rate Through the	**)**	**Direct Testimony of**
Energy Balancing Account Mechanism	**)**	**Philip Hayet**
	)	**On Behalf of the**
	)	**Utah Office of**
	)	**Consumer Services**

CONFIDENTIAL - SUBJECT TO RULE 746-100-16

Confidential Material Shaded in Gray

August 18, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip Hayet. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and Vice President of J. Kennedy and Associates, Inc. (Kennedy and Associates). I am appearing on behalf of the Office of Consumer Services ("Office").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY KENNEDY AND ASSOCIATES?

A. Kennedy and Associates provides consulting services related to electric utility system planning, energy cost recovery, revenue requirements, regulatory policy, and other regulatory matters.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Hayet Direct – Exhibit OCS-2.1. I have participated in numerous PacifiCorp and Rocky Mountain Power (or the "Company") cases including PacifiCorp's 2014 General Rate Case ("GRC") (Docket No. 13-035-184), and the last EBA proceeding covering calendar year 2013 (Docket No. 14-035-31).

I. <u>INTRODUCTION AND SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Rocky Mountain Power ("RMP" or "Company") filed a deferred net power cost ("NPC") application on March 16, 2015 referred to as the 2015 Energy Balancing Account ("2015 EBA") mechanism filing. In its Application, the Company requested approval to recover $30.5 million in deferred EBA costs for the 2014 calendar year period. My testimony proposes three changes to RMP's EBA request and recommends that RMP's deferred NPC recovery be reduced by $1,282,363 on a Utah basis.

Q. HOW DID THE COMPANY CALCULATE THE REQUESTED $30.5 MILLION INCREASE IN EBA COSTS?

A. The base amount of NPC built into rates, referred to as Base Energy Balancing Account Costs or Base EBAC, originated from two different rate cases. Base EBAC for the period of January 1, 2014 through August 31, 2014 came from the 2012 GRC, and Base EBAC for the period of September 1, 2014 through December 31, 2014 came from the 2014 GRC. When the EBAC costs from the two rate cases are combined for the appropriate periods, the combined EBAC for 2014 is $1,483 million in net power costs, and $82 million in wheeling revenue. The actual adjusted net power cost for the same period is $1,600 million.

Per stipulations in the last two GRCs, the Company calculated the EBA Deferral Amount using two different methods during different time periods. For the period of January 1, 2014 through August 31, 2014, the Company used the Scalar Method that was approved in the 2012 GRC Stipulation. For the period of September 1, 2014 through December 31, 2014, the Company used the Commission Order Method consistent with the stipulation approved in the 2014 GRC.

Using the two allocation methods for the appropriate time periods and adjusting for actual wheeling revenues, the Company derived the Utah allocated actual EBAC to be approximately $652.9 million, or $27.10/MWh when dividing by Utah Jurisdictional Sales (24,089,061 MWh).

The Utah Base EBAC dollar per megawatt hour value was calculated first by adjusting the Base Utah NPC by wheeling revenue, which yielded $599.4 million, and then dividing by projected jurisdictional sales from the prior GRCs of 23,617,980 MWh, which resulted in an amount of $25.38/MWh. The difference in the actual and base EBA rates is $1.72/MWh ($27.10/MWh – $25.38/MWh) and when applied to the actual 2014 Utah sales, the under-recovered amount for 2014 is $41.5 million ($1.72 * 24,089,061).

The deferral balance is reduced to $29.0 million after applying the 70/30 sharing band. The final EBA deferral balance is determined after accounting for interest and a true-up of wheeling revenue resulting from the Company's transmission rate case filed at the Federal Energy Regulatory Commission ("FERC") in Docket ER11-3643. Interest was accrued based on a 6.0% interest rate as follows:

Interest through December 31, 2014	$1.2 million
Interest through October 31, 2015	<u>$1.5 million</u>
	$2.7 million

In the transmission rate case, the FERC approved a settlement on May 23, 2013, to revise PacifiCorp's Open Access Transmission Rates. The settlement resulted in Utah customers receiving additional revenues of $1.2 million in 2014. The final EBA deferral balance after accounting for interest and the wheeling revenue credit is $30.5 million ($29.0 + $2.7 – $1.2).

Q. PLEASE SUMMARIZE THE ADJUSTMENTS THAT YOU RECOMMEND.

A. First, I propose two adjustments related to avoidable forced outages that resulted in the inclusion of unnecessary replacement power costs in actual net power costs. The outages occurred at the Company's Craig and Hunter plants, and the total of both adjustments reduces the Utah allocated NPC deferral by $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. I also recommend an adjustment to remove a California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM") cost that PacifiCorp should not have included in the EBA, but instead should have been deferred to the next

GRC per the Stipulation in the 2014 GRC. This adjustment reduces the Utah allocated deferral balance by **$[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. Together, these adjustments reduce the Company's deferral request by $1,282,363, which is a change in the deferral amount from $30,471,465 to $29,189,102.

II. GENERATING UNIT FORCED OUTAGE DISALLOWANCES

Q. PLEASE DISCUSS YOUR INVESTIGATION OF GENERATING UNIT FORCED OUTAGES THAT OCCURRED DURING THE EBA DEFERRAL PERIOD.

A. It is not unusual for generating units to fail and typically utilities incur higher operating costs when failures occur. However, ratepayers should not have to be responsible for bearing higher outage costs when failures are caused by operator errors, or by outages that are clearly avoidable.

In this proceeding, I reviewed forced outages that occurred during calendar year 2014 and determined there were two relatively long forced outages that could have been avoided. One outage occurred at Craig Unit 1 and the other at Hunter Unit 3. The Craig outage was also identified as an avoidable outage by the Division of Public Utilities ("Division") in its direct testimony.

Q. PLEASE DESCRIBE THE CRAIG OUTAGE.

A. The Craig Station, located near Craig, Colorado, is a 1,304 MW coal plant, which PacifiCorp owns jointly with Tri-State Generation and Transmission ("Tri-State") and other utilities (PacifiCorp's owns 19.3% of Units 1 and 2). According to the 2014 Thermal Outage Summary, the 428 MW Craig 1 unit was forced out of service on **[BEGIN CONFIDENTIAL]**[redacted]**[END**

CONFIDENTIAL], and returned to service on**[BEGIN CONFIDENTIAL]** [redacted][1] **[END CONFIDENTIAL]** In total, PacifiCorp and the other Craig unit owners experienced a loss of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** MWh during calendar year 2014.[2] Based on its 19.3% share, PacifiCorp determined the unit experienced a loss of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**MWh during the **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** hours that it was out of service.[3] **[BEGIN CONFIDENTIAL]** [redacted]

Q. [redacted]

A. [redacted][4]

[1] OCS 2.4(c)
[2] DPU 7.1 1st Supplemental.
[3] Ibid.
[4] Additional Filing Requirement 10, 1st Supplemental, “Craig U1 12 Dec 2014 DC Lube Oil Pump.pdf”.

Q. [redacted]

A. [redacted]

[Additional Filing Requirement 10, 1st Supplemental, at 2]

[redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[redacted]

[END CONFIDENTIAL]

Q. DO YOU BELIEVE THE COMPANY SHOULD BE PERMITTED TO RECOVER REPLACEMENT POWER COSTS ASSOCIATED WITH THIS OUTAGE?

A. No, I do not. The Craig 1 outage could have been avoided if **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. It would be improper to require ratepayers to pay for replacement power costs associated with such an outage.

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU RECOMMEND CONCERNING THE CRAIG UNIT 1 OUTAGE.

A. The Company's response to DPU 7.1 1st supplemental derived an estimate of the replacement power cost for the Craig 1 outage. The response provided the amount of generation that could have been produced by Craig 1 had the unit operated at its maximum capacity during the entire **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** hour outage period, which was **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. This energy was then adjusted by the same capacity factor for Craig 1 that had been derived from the Company's GRID projection used to produce base rates during the GRC. The energy was further reduced to account for PacifiCorp's Craig 1 ownership percentage of 19.28%. After applying these adjustments, PacifiCorp's estimate of the amount of the Craig Unit 1 energy that had to be replaced was **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**MWh. I then used the average $/MWh cost of operating Craig 1 from the 2014 rate case to derive what it would have cost for Craig 1 to produce **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** MWh, and I compared that to the cost of purchasing the same amount of energy from the Four Corners market. The difference in the two costs was my estimate of the System replacement cost due to the Craig 1 outage. I then computed the impact on the Utah deferral balance after accounting for the 70% sharing mechanism.[5] The proposed adjustment is presented in Hayet Direct – Exhibit OCS-2.2, which indicates that the Utah EBA deferral is reduced by $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.

Q. PLEASE DISCUSS THE HUNTER 3 OUTAGE.

The Hunter Plant, located near Castle Dale, Utah, is a jointly owned 1,320 MW coal plant. Based on the Confidential 2014 Thermal Outage Summary, the 471 MW Hunter 3 unit, owned 100% by PacifiCorp, was forced out of service on **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. According to PacifiCorp, the unit incurred an outage of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** hours during calendar year 2014, amounting to a loss of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** MWh.[6]

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[5] Since the Division also developed an adjustment for this Craig 1 outage, I used the scalar and Base NPC values found on DPU Exhibit 1.5, and I confirmed that I developed the same adjustment as the Division.
[6] OCS 2.7.

The outage was the result of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Hunter 3 cooling tower. The Significant Event Report associated with the Hunter 3 Outage indicated that the root cause was "**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**"[7] The Company's response to DPU 22.20 states that the Cooling tower was in service for 33 years, and "the typical service life for a wood structure cooling tower is 20 to 30 years depending on operating conditions."

Q. IS IT UNUSUAL TO CONSTRUCT A COOLING TOWER USING WOOD STRUCTURAL MEMBERS?

A. It is not unusual to find cooling towers that have been constructed using wood structural members. However, whenever wood is used, it is important that proper steps be taken to avoid decay and to prevent deterioration from shortening the life of the wood.

Q. ARE YOU AWARE OF WHAT CAN BE DONE TO PREVENT DETERIORATION IN A WOODEN COOLING TOWER?

A. Yes, according to a chapter in a recent General Electric Handbook of Industrial Water Treatment, "Preventive maintenance is the only effective method of protecting cooling towers from deterioration."[8] Preventive maintenance is important in order to avert any serious damage from occurring and to preserve the use of the wood as long as possible. Preventive maintenance actions include use of water treatments, performing inspections, conducting laboratory testing, applying preservatives, and replacing decayed wood.

Q. ARE YOU AWARE OF WHETHER PACIFICORP TOOK STEPS TO ENSURE [BEGIN CONFIDENTIAL] [redacted]

[7] DPU 7.1 CONF, "HTR3-04272014-Cooling Tower.doc".
[8] http://www.gewater.com/handbook/index.jsp, Chapter 29, Cooling Tower Wood Maintenance, page 1.

[redacted] **[END CONFIDENTIAL]**

A. Yes, in response to OCS 2.7, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. WHAT DID PACIFICORP DO IN 2012 AS PART OF THE 2012 OVERHAUL TO [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL] THE HUNTER 3 WOODEN COOLING TOWER?**

A. According to OCS 2.6, PacifiCorp **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. ULTIMATELY, WAS THE EFFORT SUCCESSFUL [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. No it was not. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

Q. DO YOU BELIEVE THE COMPANY SHOULD BE PERMITTED TO RECOVER REPLACEMENT POWER COSTS ASSOCIATED WITH THIS OUTAGE?

No, I do not. The Hunter 3 outage should have been avoided, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The outage could have been avoided had PacifiCorp **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL] As a result, the Hunter 3 outage replacement power costs should not be recovered from ratepayers.

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU RECOMMEND CONCERNING THE HUNTER UNIT 3 OUTAGE.

A. PacifiCorp's confidential attachment to OCS 2.7 derived an estimate of the replacement power cost to the System for the Hunter 3outage. PacifiCorp determined that the amount of generation that could have been produced by Hunter 3 had the unit operated at its maximum capacity during the **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** hour outage period was **[BEGIN CONFIDENTIAL]**[redacted]. **[END CONFIDENTIAL]** This energy was then adjusted by the same capacity factor for Hunter 3 that had been derived from the Company's GRID projection used to produce base rates during the GRC. The resulting estimate of the amount of Hunter 3 energy that had to be replaced was **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. I then used the average $/MWh cost of operating Hunter 3 from the 2014 rate case to derive what it would have cost for Hunter 3 to produce **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** MWh, and I compared that to the cost of purchasing the same amount of energy from the Four Corners market. The difference in the two costs was the estimate of the cost to the System to replace the Hunter 3 energy as a result of the outage. I have computed the impact on the Utah deferral balance after accounting for the 70% sharing mechanism. The proposed adjustment is presented in Hayet Direct – Exhibit OCS-2.3, which indicates that the Utah EBA deferral is reduced by $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.

Q. WHAT IS THE TOTAL AMOUNT OF REPLACEMENT POWER COSTS THAT YOU RECOMMEND BE DISALLOWED ASSOCIATED WITH THE HUNTER AND CRAIG OUTAGES?

A. I recommend that the Utah EBA deferral be reduced by a total of $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**. This includes the Craig Outage replacement fuel costs of $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** and the Hunter replacement fuel costs of $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.

III. EIM O&M ADJUSTMENT

Q. PLEASE EXPLAIN THIS ISSUE.

A. The 2014 GRC (Docket No. 13-035-184) was settled and included a provision requiring that certain EIM costs would have to be deferred for later consideration, as opposed to be recovered sooner through the EBA. I have identified an administrative O&M expense that PacifiCorp included in the 2014 EBA, but that instead should have been deferred pursuant to the stipulation.

Q. WHAT TYPE OF EXPENSE ARE YOU REFERRING TO?

A. PacifiCorp included in the EBA a CAISO administrative expense that has a charge code of 4564 ("GMC EIM Transaction Charge"), and that the CAISO describes as, "This EIM administrative cost covers staff and portions of ISO systems used to support EIM functionality."[9]

[9] Attach DPU 25.1 -2.zip, BPM – 4564 GMC EIM Transaction Charge_5.pdf

Q. DO YOU BELIEVE IT WAS APPROPRIATE TO INCLUDE THAT EXPENSE IN THE EBA?

A. No I do not. In the 2014 GRC, Mr. Greg Duval initially proposed that CAISO administrative O&M costs that are not considered net power costs should "…be passed back to customers via the EBA".[10] The Office opposed including any O&M expenses in the EBA and recommended that only CAISO market charges should be included because PacifiCorp had not yet demonstrated that power cost savings would exceed the projected capital and O&M expenses.[11] Instead the Office supported PacifiCorp being allowed to defer administrative O&M costs for consideration in a future rate case.

Q. WHAT DID THE PARTIES AGREE TO IN THE STIPULATION, AND WHAT DID THE COMMISSION DECIDE?

A. The parties agreed to the following language that was included as part of paragraph 30 of the stipulation:

> The Parties agree that the Commission may enter a deferred accounting order to permit the Company to begin to defer a) Utah's allocated portion of energy imbalance market ("EIM")-related operations and maintenance expenses incurred on or after September 1, 2014, and b) depreciation expense related to capital investments necessary to implement EIM recorded on or after September 1, 2014 for potential recovery from customers pursuant to a Commission order in a future rate case.

The Commission adopted this language in the order it issued on August 29, 2014.

Q. WHAT IS THE AMOUNT OF THE O&M EXPENSE THAT SHOULD HAVE BEEN DEFERRED?

A. The expense related to charge code 4564 included in the EBA amounts to **$[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.

[10] Greg Duvall Direct Testimony, Docket No. 13-035-184, January 3, 2014, line 659.
[11] Donna Ramos Direct Testimony on behalf of the Office of Consumer Services, Docket No. 13-035-184, May 1, 2014, line 1771 1749.

Q. DOES THE CAISO CHARGE FOR OTHER ADMINISTRATIVE EXPENSES SIMILAR TO THIS AND DID PACIFICORP INCLUDE THOSE IN THE EBA?

A. The CAISO charges PacifiCorp for Grid Management Charges ("GMC"), which are other administrative fees designed to cover Market Service Charges and System Operations Charges, and PacifiCorp does not appear to include those GMC charges in the EBA, which is consistent with the requirements of the Stipulation.

Q. IS THE $[BEGIN CONFIDENTIAL][redacted][END CONFIDENTIAL] ADMINISTRATIVE CHARGE SIMILAR TO THE GMC CHARGES THAT WERE NOT INCLUDED IN THE EBA?

A. Yes the $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** charge (CAISO charge code 4564) and GMC charges are similar. As mentioned above, the CAISO's label for the $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** charge states that it is an administrative cost that "covers staff and portions of ISO systems used to support EIM functionality." This means it is similar to the GMC charges because both address market services and system operations items. The CAISO Business Practice Manual even states this about charge code 4564:[12]

> The Energy Imbalance Market (EIM) administrative charge was derived through by evaluating the components of existing administrative charges and determining what aspects of the services provided are attributable to EIM functions. The EIM Administrative Charge rate represents the amount all users of these real-time services pay – it is not a new charge but rather a way to evaluate the actual costs of running the elements of the ISO market that the ISO will be offering as EIM functions. The rate is driven by the volume for the entire market, including California, that gets the services that the EIM participants will be purchasing.

Furthermore, the CAISO Business Practice Manual essentially admits that the $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** charge covers GMC

[12] Attach DPU 25.1 -2.zip, BPM – 4564 GMC EIM Transaction Charge_5.pdf.

components, as it states "EIM revenue will be applied to the ISO GMC components which reduces the costs that need to be recovered from ISO market participants." Thus, both of these are O&M administrative expenses, and just as PacifiCorp deferred the GMC charges, it should also defer CAISO code 4564 charges as well.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE $347,300 ADMINISTRATIVE CHARGE?

A. I recommend that the Company be required to remove this charge from the EBA and instead defer it for consideration in the next rate case. I have computed the impact on the Utah deferral balance after accounting for the 70% sharing mechanism. The proposed adjustment is presented in Hayet Direct – Exhibit OCS-2.4, which indicates that the Utah EBA deferral is reduced by $**[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.

IV. NON-OWNED WIND GENERATION INTEGRATION COSTS

Q. IN THE LAST EBA PROCEEDING (DOCKET NO. 14-035-31) YOU ADDRESSED AN ANCILLARY SERVICES COST ISSUE RELATED TO NON-OWNED WIND RESOURCES. ARE YOU STILL CONCERNED ABOUT THAT?

A. Yes, I am, and I still believe it should be addressed. However, now that PacifiCorp has joined the CAISO EIM, I believe this should be investigated at the same time that other questions about the EIM are addressed.

Q. PLEASE EXPLAIN THIS ISSUE.

A. PacifiCorp is obligated by the Federal Energy Regulatory Commission ("FERC") to provide ancillary services to transmission customers using generation resources that retail customers have paid for. Third-party wind generators are located within the Company's balancing authority and transmission provider service area, but do not provide power to serve Company load. In general rate cases, retail customer rates are set and include the impact of providing operating reserves to the non-owned wind generators. In turn, retail rates are adjusted to account for revenues that PacifiCorp recovers from those generators based on Open Access Transmission Tariff ("OATT") rates that were approved by FERC. With regard to the non-owned wind generators the ancillary service in the OATT tariff at issue is Schedule 3a, which relates to providing regulation service to transmission customers. The Office has argued in the past that retail customers are charged more for the operating reserves than the revenues that are credited back based from the OATT revenues.

Q. HOW DOES THIS ISSUE RELATE TO THE CAISO EIM?

A. The Company has argued in the past that it also credits retail customers for OATT Schedule 9 revenues, which compensate retail customers for energy imbalance costs when there is a difference between actual energy output of third-party generators and the scheduled output of those generators.[13] The Company has argued that when the energy imbalance revenues are also accounted for retail customers are fairly compensated, though the Company has never proven this. Even if the Company were to try to prove this at this time, it is now part of the CAISO EIM market, and any evaluation should account for the fact that its OATT tariff has been revised to reflect that energy imbalance charges and revenues are based on the CAISO LMP methodology.

[13] Note that Schedules 3A and 9 apply to third-party generators located within PacifiCorp's balancing authority area that export to non-PacifiCorp loads located outside of the area. The same logic applies when the third-party generator serves non-PacifiCorp load located within the balancing authority area, but in that case, similar but different schedules are used (Schedules 3 and 4).

Q. IN A PRIOR PROCEEDING DID THE OFFICE ARGUE THAT PACIFICORP SHOULD REVISE ITS FERC TARIFF TO CHARGE REVENUES THAT WOULD FULLY RECOVER COSTS THAT THE NON-OWNED WIND RESOURCES CAUSE PACIFICORP TO INCUR?

A. Yes, in the 2013 EBA (Docket No. 13-035-32), Office Witness Dan Gimble stated, "In order for PacifiCorp's OATT rate to be fully compensatory, it should recover both the <u>fixed</u> and the <u>variable</u> costs of providing wind integration services."[14] Mr. Gimble recommended that in a future FERC rulemaking, PacifiCorp should add an additional variable cost component to account for integration costs caused by wind resources.

Q. HAS PACIFICORP FILED ANYTHING YET AT FERC TO ADD A VARIABLE COST COMPONENT TO SCHEDULE 3A?

A. No, PacifiCorp still has not done this, though in the 2014 EBA PacifiCorp witness Brian Dickman stated "PacifiCorp anticipates operational improvements in its ability to identify regulating reserve requirements in conjunction with its planned October 2014 implementation of the EIM."[15] Mr. Dickman also mentioned that the Company was targeting 2016 to make a FERC filing in order "To allow a full year of EIM operational data…"[16]

Q. WHAT DO YOU RECOMMEND CONCERNING THE COSTS CAUSED BY NON-OWNED WIND GENERATORS?

A. I still believe that revenues received from wholesale transmission customers for ancillary services based on the FERC regulated OATT should fairly compensate PacifiCorp for the costs it incurs in providing those services. I also still believe that retail customers should

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[14] Docket 13-035-32, Gimble Redacted Direct, Pg. 5, lines 130-131.
[15] Brian Dickman Rebuttal Testimony, Docket No. 14-035-31, September 23, 2014, beginning at line 214.
[16] Ibid at line 217.

not have to make up for any costs caused by the non-owned wind generators due to deficiencies in the FERC tariff. However, now that PacifiCorp has joined the EIM, it is entirely possible that the Company's costs for providing those ancillary services will decline, which would mitigate the impact caused by non-owned wind generators. Since PacifiCorp is very close to having "a full year of EIM operational data", and since PacifiCorp will soon need to conduct evaluations of the costs and benefits of the EIM, I recommend that PacifiCorp should be required to evaluate the costs imposed by non-owned wind generators, to determine if those costs are fairly matched by the revenues that those customers pay. If it is found that PacifiCorp is being under-compensated, then PacifiCorp should be required to address this in its next FERC filing, which should occur no later than during 2016.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.