Witness OCS 2D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power to Increase The Deferred EBA Rate Through the Energy Balancing Account Mechanism	)))))))	**Docket No. 14-035-31** **Direct Testimony of Philip Hayet On Behalf of the Utah Office of Consumer Services**

REDACTED

August 28, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip Hayet. My business address is 215 Huntcliff Terrace, Sandy Springs, Georgia.

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

A. I am a utility regulatory consultant and President of Hayet Power Systems Consulting ("HPSC"). I am appearing on behalf of the Office of Consumer Services ("Office").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY HPSC?

A. HPSC 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 Exhibit OCS 2.1D.

I. INTRODUCTION AND SUMMARY

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 17, 2014, referred to as the 2014 Energy Balancing Account ("2014 EBA") mechanism filing. In its Application, the Company requested approval to recover $28,339,553 in deferred EBA costs for the 2013 calendar year period. This includes various credits and interest accumulated during the deferral period. My testimony proposes two changes to RMP's EBA request and recommends that RMP's deferred NPC recovery be reduced by $2,459,553 on a Utah basis.

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE PURPOSE AND OPERATION OF THE EBA?

A. The EBA was established as a mechanism to provide RMP an opportunity to recover a portion of the difference between the actual amount of NPC it incurs and the base amount of NPC built into rates during a prior general rate case proceeding. EBA costs authorized for recovery by the Commission are collected from customers via a change in Tariff Schedule 94. The Company states in its Application at page 3, that its request is consistent with the Commission's EBA Order issued July 17, 2012, and amended Order issued August 30, 2012 in Docket 11-035-T10.[1] In establishing the EBA, the Commission implemented a sharing band in order to provide the Company financial incentives to minimize NPC, such that customers pay 70% of the difference between actual and base NPC. Total system NPC is allocated to Utah using the "Scalar Method" as agreed to in the Settlement resolving the 2012 General Rate Case ("2012 GRC") in Docket No. 11-035-200.[2]

Q. HOW DID THE COMPANY CALCUATE THE REQUESTED $28.3 MILLION INCREASE IN EBA COSTS?

A. From the 2012 GRC, the total Company base NPC being used in this case is $1.479 billion for the calendar year 2013 deferral period, and the actual Total Company NPC for the same period is $1.620 billion. Using the Scalar Method to derive the costs on a Utah basis, the actual Utah NPC, adjusted for wheeling revenue, is $661,403,752. Using actual 2013 Utah sales of 24,456,528 MWh, the 2013 actual EBA rate is $27.04/MWh.

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[1] In the Matter of: In compliance with the September 13, 2011 Order approving the Settlement Stipulation in Docket Nos. 10-035-124, 09-035-15, 10-035-14, 11-035-46, and 11-035-47, Rocky Mountain Power is filing the proposed Schedule 94, Energy Balancing Account (EBA) Pilot Program.

[2] The same approach was used in the 2013 EBA as adopted in the settlement resolving the 2011 GRC in Docket No. 10-035-124.

The base Utah EBA dollar per megawatt hour value was calculated using the base Utah NPC, adjusted for wheeling revenue, $603,783,830, and jurisdictional sales from the 2012 GRC of 23,734,643 MWh, which resulted in an amount of $25.44/MWh. The difference in the actual and base EBA rates is $1.61/MWh ($27.04/MWh – $25.44/MWh) and when applied to the 2013 Utah sales, the under-recovered amount for 2013 is $39,454,809 ($1.61 * 24,456,528).

The deferral balance is reduced to $27,618,366 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 ER11-3643-000. Interest was accrued based on a 6.0% interest rate as follows:

Interest through December 31, 2013	$470,671
Interest through October 31, 2014	$1,378,778
	$1,849,449

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 a credit of $1,128,262 for greater wheeling revenues prior to December 31, 2013, than had been included in Utah base rates established in the 2012 GRC. The final EBA deferral balance after accounting for interest and the wheeling revenue credit is $28,339,553 ($27,618,366 + $1,850,449 – $1,128,262).

Q. PLEASE SUMMARIZE THE ADJUSTMENTS THAT YOU RECOMMEND.

A. In my direct testimony, I propose two adjustments to RMP's EBA request. The first adjustment disallows the inclusion of unnecessary replacement power costs resulting from avoidable forced outages at the Company's [redacted] plants. This adjustment reduces the Utah NPC deferral by $1,560,892. The second adjustment removes variable costs charged to Utah retail customers caused by non-owned, wholesale wind generators that take wind integration services from PacifiCorp. This adjustment reduces the Utah NPC deferral by $898,661. Together, the Outage and Non-Owned Wind Adjustments reduce the deferral balance by $2,459,553 resulting in a final EBA deferral of $25,880,000.

II. GENERATING OUTAGE DISALLOWANCES

Q. PLEASE DISCUSS YOUR INVESTIGATION OF GENERATING UNIT 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, I do not believe that ratepayers should be responsible for bearing the cost of outages caused by operator error on the part of the utility, or outages that were otherwise avoidable.

In this proceeding, I reviewed forced outages that occurred during calendar year 2013 and determined there were two relatively long outages that could have been avoided. One outage occurred at [redacted] and the other affected the [redacted] plant. These two outages were initially identified by the Division of Public Utilities ("Division") in its direct EBA testimony.

Q. PLEASE DISCUSS THE [redacted] OUTAGE.

[redacted] According to the 2013 Thermal Outage Summary, [redacted] Unit 1 was forced out of service on [redacted], and returned to service on [redacted]. In total, PacifiCorp [redacted] experienced a loss of [redacted] MWh. Based on [redacted] it experienced a loss of [redacted] MWh during the [redacted] hours that the unit was out of service.

The Root Cause Analysis associated with the [redacted] Outage indicated that [redacted][3] [redacted] In other words, the Root Cause Analysis indicates that [redacted], the unit would not have suffered the damage and the outage would have been avoided.

[3] [redacted]

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Q. DO YOU BELIEVE THE COMPANY SHOULD BE PERMITTED TO RECOVER EXCESS REPLACEMENT POWER COSTS ASSOCIATED WITH SUCH AN OUTAGE FROM RATEPAYERS?

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

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU DERIVED CONCERNING THE [redacted] OUTAGE.

A. The 2013 Thermal Outage Summary[4] indicated that the lost generation from the [redacted] unit was [redacted] MWh. I multiplied that energy by a capacity factor of [redacted]% obtained from the Company's GRID projection made during the 2012 GRC, and further by PacifiCorp's ownership percentage [redacted], to calculate the amount of energy that was lost during the outage, which equaled [redacted] MWh [redacted]. I then determined the excess cost of replacement power incurred in serving PacifiCorp load during the outage, and removed that from the deferral balance. To determine the excess cost resulting from the outage, I compared the cost that PacifiCorp would have incurred had [redacted] operated during the outage period to the cost of purchasing replacement power at the [redacted] market. The proposed adjustment is presented in Exhibit No. 2.2D, which indicates that the Utah EBA deferral is reduced by $929,825.

Q. PLEASE DISCUSS THE [redacted] OUTAGE.

The [redacted]. According to the Confidential 2013 Thermal Outage Summary, the [redacted]

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[4] Attach EBA FR 6 -6 CONF, 2013 Thermal Outage Summary CONF.xlsx

[redacted] In total, the plant incurred an outage of [redacted] hours causing [redacted] to be out of service.

[redacted][5] [redacted]

Q. IS THERE ANYTHING UNUSUAL TO NOTE REGARDING THE [redacted] OUTAGE?

A. [redacted]

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[5] EBA AFR 10 1st Supplemental, [redacted]

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[redacted]

[redacted]

Q. DO YOU BELIEVE THE COMPANY SHOULD BE PERMITTED TO RECOVER EXCESS REPLACEMENT POWER COSTS ASSOCIATED WITH SUCH AN OUTAGE FROM RATEPAYERS?

No, I do not. It appears from the root cause analysis [redacted] of the plant in late 2013 could have been avoided.

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU DERIVED CONCERNING THE [redacted] OUTAGE.

A. PacifiCorp's attachment to EBA FR 6-6, 2013 Thermal Outage Summary CONF.xlsx, indicated that the lost generation from the [redacted] was [redacted] MWh. I multiplied that energy by a capacity factor of [redacted]% obtained from the Company's GRID projection made during the 2012 GRC to calculate the amount of energy that was lost during the outage which is [redacted] I then determined the excess cost of replacement power incurred in serving PacifiCorp load during the outage, and removed that from the deferral balance. To determine the excess cost, I compared the cost that PacifiCorp would have incurred had [redacted] operated during the outage period to the cost of purchasing replacement power at the [redacted]. The adjustment is presented in Exhibit No. 2.3D and the Utah EBA deferral is reduced by $631,067.

Q. WHAT IS THE TOTAL AMOUNT OF EXCESS REPLACEMENT POWER COSTS THAT YOU RECOMMEND BE DISALLOWED ASSOCIATED WITH THE [redacted] AND [redacted] OUTAGES?

A. I recommend that the EBA deferral be reduced by a total of $1,560,892.

III. <u>NON-OWNED WIND GENERATION INTEGRATION COSTS</u>

Q. PLEASE EXPLAIN THIS ISSUE.

A. The Company's Open Access Transmission Tariff ("OATT") requires that PacifiCorp provide regulation reserve transmission services to third-party wind generation owners through Schedules 3 and 3a. The revenue PacifiCorp receives from third-party wind generators for these integration services only covers capacity reservation costs and does not cover variable costs (fuel and purchase power). Since the Company includes the total costs for these services in the Utah base NPC, Utah retail customers are currently subsidizing these third-party wind generators. Thus, at its core, this issue is one of cost causation and fairness as the Company is charging Utah retail customers for the costs directly caused by third-party wind generators.

Q. PLEASE IDENTIFY THE THIRD-PARTY WIND PROJECTS THAT USED PACIFICORP'S TRANSMISSION SYSTEM AND WERE PROVIDED WIND INTEGRATION SERVICES DURING THE 2013 EBA DEFERRAL PERIOD.

A. During calendar year 2013, PacifiCorp provided wind integration services to at least four third-party wind projects: [redacted][6] None of the output from these wind facilities served PacifiCorp's retail load.

Q. DID THE OFFICE ADDRESS PACIFICORP'S WIND INTEGRATION COSTS IN THE LAST EBA PROCEEDING (DOCKET NO. 13-035-32)?

A. Yes. Office Witness Mr. 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."[7]

Q. WHAT DID THE OFFICE RECOMMEND IN THAT PROCEEDING?

A. Mr. Gimble did not recommend an adjustment but advised that "If a future FERC rulemaking or other policy mandate allows utilities to add a variable cost component to the charge for wind integration services, PacifiCorp should promptly petition the FERC to change its OATT accordingly."[8]

[6] OCS Data Request 2.5d.
[7] Docket 13-035-32, Gimble Redacted Direct, Pg. 5, lines 130-131.
[8] Docket 13-035-32, Gimble Redacted Direct, Pg. 5, lines 145-147.

Q. HAS PACIFICORP TAKEN ANY ACTION BEFORE THE FERC TO INCREASE THE CHARGES TO NON-OWNED WIND GENERATOR FOR THESE WIND INTEGRATION SERVICES?

A. Yes. At approximately the time that the last EBA proceeding was taking place, PacifiCorp was concluding a hearing before the FERC in Docket No. ER13-1206. In that docket, PacifiCorp requested the authority to increase its Schedule 3a Tariff rates associated with variable energy resources ("VERs"), such as wind generators that serve loads outside of the PacifiCorp System. According to testimony filed by Sarah Edmonds, Director of Transmission Regulation, Strategy & Policy for PacifiCorp, the Company's request would ensure that there would be no cost recovery gap for VERs selling power to loads outside of PacifiCorp's system.[9]

Q. WHAT WAS THE OUTCOME OF PACIFICORP'S REQUEST?

A. In August 2013, FERC rejected PacifiCorp's request as not being just and reasonable because PacifiCorp did not fully account for cost savings that would result from intra-hour scheduling that was available to third-party wind generators. Had that been considered in PacifiCorp's proposal, FERC may have approved PacifiCorp's request.

Q. HAS PACIFICORP REVISED ITS CALCULATIONS AND REFILED AT FERC?

A. No it has not. Even though FERC rejected PacifiCorp's filing without prejudice, PacifiCorp has not re-filed its request to modify Schedule 3a. According to the Company's response to OCS Data Request 2.2, the earliest PacifiCorp plans to re-file is early 2016 in order "To allow a full year of EIM operational data in addition to Order 764 operational reforms."

[9] Sarah Edmonds testimony found, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13218867, pg. 14, at 7.

Q. IS IT REASONABLE FOR PACIFICORP TO CHARGE RETAIL CUSTOMERS FOR COSTS CAUSED BY THIRD-PARTY WIND GENERATORS?

A. No. If PacifiCorp believed that it was not being adequately compensated by third-party wind generators that sell off-system, it could have re-filed at FERC right away, rather than deciding to wait until 2016. Therefore, I recommend that the EBA deferral should be adjusted to remove intra-hour integration costs associated with third-party wind generators.

Q. HAS ANY STATE COMMISSON THAT IS CHARGED WITH SETTING PACIFICORP'S RETAIL RATES ISSUED A DECISION THAT DISALLOWS RECOVERY OF THE VARIABLE COSTS ASSOCIATED WITH THIRD-PARTY WIND INTEGRATION?

A. Yes. In an Order issued in early 2011, the Idaho Public Utilities Commission expressly found that "the responsibility for recovery of wind integration costs from wholesale transmission customers resides with the Company, not its retail customers."[10]

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT?

A. I developed an adjustment to remove the value of the third-party wind integration cost that PacifiCorp imposed on retail customers during the 2013 deferral period. I identified the amount of energy produced by the non-owned wind generators in 2013, and multiplied that energy by PacifiCorp's intra-hour wind integration charge ($[redacted] MWh) developed in the 2012 GRC in Docket No. 11-035-200. I used this price to impute revenues for the variable cost of wind integration services that the wholesale wind generation customers should have paid to PacifiCorp.

[10] Idaho Public Utilities Commission Docket No. PAC-E-10-07, Order 32196, February 28, 2011, Page 30.

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT TO THE UTAH EBA DEFERRAL?

A. This adjustment is presented in Exhibit No. 2.4D. This adjustment reduces the Utah EBA deferral by $898,661.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

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