Gary A. Dodge, #0897
Hatch, James & Dodge
10 West Broadway, Suite 400
Salt Lake City, UT 84101
Telephone: 801-363-6363
Facsimile: 801-363-6666
Email: gdodge@hjdlaw.com

Attorneys for UAE Intervention Group

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**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[Public Version]

The UAE Intervention Group (UAE) hereby submits the Prefiled Direct Testimony of Kevin C. Higgins.

DATED this 28th day of August, 2014.

/s/______________________________
Gary A. Dodge,
Attorney for UAE

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 28th day of August, 2014, on the following:

Rocky Mountain Power:

Jeff Richards	jeff.richards@pacificorp.com
Yvonne Hogle	yvonne.hogle@pacificorp.com.com
Dave Taylor	dave.taylor@pacificorp.com

Division of Public Utilities:

Patricia Schmid	pschmid@utah.gov
Justin Jetter	jjetter@utah.gov
Chris Parker	chrisparker@utah.gov
Artie Powell	wpowell@utah.gov
Dennis Miller	dmiller@utah.gov

Office of Consumer Services:

Brent Coleman	brentcoleman@utah.gov
Michele Beck	mbeck@utah.gov
Cheryl Murray	cmurray@utah.gov
Dan Gimble	dgimble@utah.gov

/s/______________________________________

BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 14-035-31

[Public Version]

August 28, 2014

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Utah Association of Energy Users Intervention Group ("UAE").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. Since 1984, I have testified in thirty-two dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in approximately 150 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission ("FERC") and prepared expert reports in state and federal court proceedings involving utility matters.

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

A. My testimony addresses the request by Rocky Mountain Power ("RMP") for recovery of $28.3 million in Energy Balancing Account ("EBA") related costs for the period January 1, 2013 through December 31, 2013 (referred to as the "2014 EBA" filing by RMP). This $28.3 million is comprised of $27.6 million of Deferred 2013 EBA costs, a credit of $1.1 million of incremental wheeling revenue related to RMP's FERC transmission rate case, plus $1.8 million of accrued interest. The EBA adjusts rates based on the differential between actual Net Power Cost ("NPC") (plus wheeling revenues) and Base NPC (plus wheeling revenues) included in rates. Pursuant to the approved EBA mechanism, customers are responsible for 70% of this differential and the Company is responsible for the remaining 30%. I recommend several adjustments to the Company's EBA calculation that are in the public interest and would result in just and reasonable rates.

Q. What EBA-related revenue increase is RMP seeking for the Utah jurisdiction?

A. As noted above, in its direct filing, RMP proposed a deferred NPC adjustment of $28.3 million, which RMP proposes to recover over a one-year period beginning November 1, 2014. As shown in Exhibit RMP ___ (JRS-1), this $28.3 million would represent a 1.5% overall increase relative to the stipulated Step 2 revenues included in RMP's 2011 rate case, Docket 11-035-200.

Q. Please summarize your primary conclusions and recommendations concerning RMP's proposed EBA rate adjustment.

A. I offer the following conclusions and recommendations:

(1) I recommend disallowing the expenses associated with the variable cost of third-party wind integration from the EBA test period. Excluding any interest impacts, the adjustment reduces the Utah NPC deferral by **$1,204,410**.

(2) I recommend disallowing the transmission expense for the DC Intertie. Excluding any interest impacts, the adjustment reduces the NPC deferral by **$1,446,806**

(3) I recommend disallowing the incremental costs associated with a forced outage at Colstrip Unit 4. Excluding any interest impacts, the adjustment reduces the Utah NPC deferral by **$1,961,610**.

These adjustments are summarized in Table KCH-1 below. The amounts shown in the table are the estimated impacts on the Utah EBA deferral balances, after taking account of the 70/30 sharing noted above. The estimates shown in Table KCH-1 below exclude any interest impacts.

Table KCH-1

Summary of UAE EBA Adjustments
(Excludes Interest Impacts)

	Utah Customer Share
1. Third Party Wind Integration Revenue Adjustment	**($1,204,410)**
2. DC Intertie Transmission Expense Adjustment	**($1,446,806)**
3. Colstrip Unit 4 Forced Outage Expense Adjustment	**($1,961,610)**
Total UAE Adjustments	**($4,522,608)**

These adjustments focus on a limited number of issues and should not be viewed as precluding adjustments proposed by other parties who may have examined other issues.

<u>Adjustment 1: Third-Party Wind Integration Costs</u>

Q. Does PacifiCorp's Open-Access Transmission Tariff ("OATT") include any charges for wind integration services?

A. PacifiCorp's OATT provides for charges for reserves for transmission customers, but it does not provide any charges for wind integration services that are comparable to the wind integration costs included in NPC and charged to retail customers. Specifically, the OATT does <u>not</u> include any recovery of the opportunity cost of holding back reserves to support wind integration that are recovered in NPC, but only includes the fixed (capital-related) costs associated with providing wind integration to wholesale customers.

Q. Does RMP charge retail customers for the opportunity cost of wind integration?

A. Yes. The opportunity costs associated with wind integration are incorporated into NPC whenever base NPC is set in a general rate case. This cost represents the opportunity cost of the capacity that RMP holds back to provide reserves to follow the variations of the Company's wind fleet. That is, when capacity is held back to accommodate the variability in wind, it is not available to make off-system sales, the margins from which provide a credit against NPC.

This opportunity cost is distinct from the fixed cost of the reserves themselves, which is recovered largely through depreciation expense and the Company's return on rate base. The wind integration costs included in NPC that were recovered in rates during Calendar Year 2013 were established in the 2011 general rate case (Docket 11-035-2000). In that case, RMP included wind integration costs of $3.44/MWh in NPC to recover the opportunity cost component of wind integration costs. I note that when actual NPC is measured for the purpose of the EBA, the opportunity costs of wind integration costs are not separately identified, but are embedded in the total NPC incurred during the EBA test period.

Q. Did PacifiCorp provide wind integration services to wind projects that do not serve RMP retail load?

A. Yes. During the EBA test period, the Company provided integration services to several wind projects, none of which serve RMP retail load: Campbell, Horse Butte, Jolly Hills, Long Hollow, BPA Foote Creek II, and PSCo Foote Creek III.[1]

Q. How does RMP propose to recover the opportunity costs associated with providing wind integration services to third-party wind projects?

A. The opportunity costs of providing wind integration for these customers are embedded in the actual NPC that was incurred during the EBA test period. Because these costs are not recovered in PacifiCorp's OATT, the Company is

[1] Source: RMP Responses to OCS DR No. 2.5 and UAE DR No. 4.4.

attempting to have retail customers absorb these costs in retail rates. This cross subsidy is both unjust and unreasonable, as the Company should not be allowed to charge retail customers for the cost of providing wholesale services to non-retail customers. I recommend adjusting NPC recoverable from Utah customers to assign a pro rata share of wind integration costs to third-party wind facilities.

Q. Have regulators in other states disallowed recovery of variable costs associated with third-party wind integration?

A. Yes. 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."[2]

Q. Why is the recovery of wind integration costs at issue in this proceeding if RMP already committed to defer Utah's allocated share of the incremental revenues associated with the company's FERC rate case in Docket No. 11-035-200?

A. RMP is obligated, according to Paragraph 51 of the Commission-approved Settlement Agreement in Docket No. 11-035-200 et al, to defer for the benefit of its Utah retail customers any incremental revenues associated with its FERC rate case in Docket No. ER11-3643-000. The FERC rate case was filed on May 26, 2011, and included updated charges for ancillary services, including a new Schedule 3A governing generator regulation and frequency response service.

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

Interim FERC rates went into effect January 1, 2012 and final rates for Schedule 3A were effective March 1, 2013.

However, as discussed above, the rates for this ancillary service do not include the variable costs associated with wind integration of the sort that are charged to retail customers. As a result, even though increased revenues associated with Schedule 3A have been deferred and included in this 2013 EBA test period, this deferral does not include the opportunity costs incurred in support of wind integration for third-party wind projects.

Q. How did you determine the cost for providing wind integration services to third-party wind projects?

A. The cost is based on the wind integration costs included in the NPC proposed by RMP for recovery from Utah retail customers in RMP's 2011 general rate case, Docket No. 11-035-200, which established the Base NPC in rates applicable to the 2013 EBA calendar year. As I noted above, in Docket 11-035-200, RMP proposed to include wind integration costs of the $3.44/MWh in Base NPC. The Company derived this unit cost by estimating the total opportunity cost of providing wind integration for the wind resources used to serve RMP's retail load *as well as for third-party wind resources*. However, under RMP's approach, the entirety of this opportunity cost is absorbed by retail customers alone. My adjustment imputes the $3.44/MWh wind integration cost calculated by RMP to the third-party wind resources, thus providing a partial offset to the opportunity costs absorbed by retail customers.

Q. What is the revenue requirement impact of your adjustment?

A. This adjustment is presented in UAE Confidential Exhibit 1.1. The adjustment reduces the Utah EBA deferral by **$1,204,410**.

Adjustment 2: DC Intertie Agreement Disallowance

Q. Please briefly describe the DC Intertie contract.

A. This contract provides 200 MW of transfer capability to import purchases from the Nevada Oregon Border ("NOB") to PacifiCorp load centers in the Northwest, such as Central Oregon.

Q. Was the DC Intertie used during the 2013 EBA calendar year?

A. During the 2013 EBA calendar year, the primary use of the DC Intertie contract was to facilitate system balancing transactions, but it was utilized only sporadically, and rarely to its full capacity. In RMP's EBA Additional Filing Requirement Confidential Attachment EBA FR 6 -2, RMP identified only [redacted] transactions that "could" have utilized the DC Intertie Agreement. These transactions occurred on only [redacted] days out of 365 days during 2013. Total deliveries were only [redacted] MWh. The DC Intertie was used in only [redacted] of the 8,760 annual hours. Although the average utilization was [redacted] MW per hour of the total 200 MW contract [redacted],[3] the [redacted] meaning that during an average hour, the Company utilized less than [redacted]

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[3] ([redacted] MWh ÷ [redacted] hrs) = [redacted] MW/hr. The [redacted] hours is derived from RMP's Response to UAE Data Request No. 4.1 in Utah General Rate Case, Docket 13-035-184 [Used with RMP Permission].

[redacted] perecent of the DC Intertie capacity it purchased.[4] The average transmission cost of these deliveries during the EBA test period, taking into account the fixed costs of the DC Intertie contract, was in excess of [redacted]/MWh,[5] which is nearly [redacted] times the average embedded retail cost of RMP's transmission service.

Q. Did RMP ever utilize the full capacity of its DC Intertie transmission rights during 2013?

A. Yes, but the full 200 MW of transfer capability was utilized for only [redacted] out of 8,760 hours during the year.[6]

Q. What was the original purpose of this contract?

A. My understanding is that the DC Intertie contract was executed in 1994 to provide deliveries of 200 MW of power from Southern California Edison at the NOB. RMP terminated the associated power purchase effective January 1, 2002, but the DC Intertie contract nonetheless remains in effect, although it is seldom used. It costs the Company and its ratepayers $4.748 million per year to purchase this transmission. My understanding is that the Company has not undertaken any steps to determine if there are options available to renegotiate, modify, terminate or buy out of the contract.

Q. What is your recommended adjustment for the DC Intertie Agreement?

A. As demonstrated above, the contract provides very few benefits in relation to its costs. I recommend that the Commission disallow recovery of the $4.748

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[4] ([redacted] MWh ÷ 8,760 hr) = [redacted] MWh/hr. [redacted] MW/hr ÷ 200 MW/hr = [redacted]%.

[5] $4.748 million / [redacted] MWh = $[redacted]/MWh.

[6] The [redacted] hours is derived from RMP's Response to UAE Data Request No. 4.1 in Utah General Rate Case, Docket 13-035-184 [Used with RMP Permission].

million attributable to the DC Intertie Agreement because the cost is unreasonable in relation to the benefit. This adjustment is presented in UAE Confidential Exhibit 1.2. The adjustment reduces the EBA deferral by **$1,446,806**.

<u>Adjustment 3: Colstrip Unit 4 Outage Disallowance</u>

Q. Do you have any adjustments for forced plant outages that are not identified in the Division of Public Utilities' audit?

A. Yes, I recommend an adjustment for a forced outage event at Colstrip Unit 4.

Q. Can you please describe the forced outage event at Colstrip Unit 4?

A. Yes. Colstrip Unit 4 was forced out of service [redacted]. The unit remained off-line [redacted]. The total outage time was [redacted] hours.

Q. What caused the forced outage?

A. According to RMP's Colstrip Unit 4 Core Failure Root Cause Analysis Report, the outage was caused [redacted]."[7] In my opinion, it is not reasonable for customers, who are already paying RMP for the cost of owning its share of Colstrip Unit 4, to bear the incremental costs

[7] Colstrip 4 Root Cause Analysis Report provided in RMP's Confidential Response to UAE Data Request No. 2.4. [redacted]

associated with the unit being unavailable for [redacted]. RMP should bear the replacement power cost of this type of unplanned outage and perhaps should seek redress from its maintenance contractors.

Q. Can you please explain how you derived your adjustment related to this outage?

A. The lost generation from this outage was [redacted] MWh.[8] My adjustment removes the incremental cost associated with market purchases necessary to replace this power. I estimated this amount by multiplying this lost generation by the difference between the [redacted] market prices at Mid-Columbia and the [redacted] generation cost for the Colstrip plant from the GRID model used in the Utah general rate case Docket 11-035-200 applicable to establishing NPC for this period. I used the Mid-Columbia market prices for this purpose because the Mid-Columbia market is used by RMP as the reference market for the Colstrip plant in the GRID dispatch model.

Q. What is the resulting revenue requirement impact of this adjustment?

A. This adjustment is presented in UAE Confidential Exhibit 1.3. The adjustment reduces the Utah EBA deferral by **$1,961,610**.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[8] Note, I corrected an apparent error in the information provided in RMP's Response to UAE Data Request 2.4 to derive the lost generation amount.