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 for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	**Docket No. 11-035-200**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT]

PUBLIC VERSION

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

DATED this 11th day of June, 2012.

/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 11th day of June, 2012, on the following:

Mark C. Moench
Yvonne R. Hogle
Daniel E. Solander
Rocky Mountain Power
201 South Main Street, Suite 2300
Salt Lake City, Utah 84111
mark.moench@pacificorp.com
yvonne.hogle@pacificorp.com
daniel.solander@pacificorp.com

Patricia Schmid
Wesley D. Felix
Assistant Attorneys General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111
pschmid@utah.gov
wfelix@utah.gov

Paul Proctor
Assistant Attorney General
160 East 300 South, 5th Floor
Salt Lake City, UT 84111
pproctor@utah.gov

F. Robert Reeder
William J. Evans
Vicki M. Baldwin
Parsons Behle & Latimer
One Utah Center, Suite 1800
201 S Main St.
Salt Lake City, UT 84111
BobReeder@pblutah.com
BEvans@pblutah.com
VBaldwin@pblutah.com

Holly Rachel Smith, Esq.
Hitt Business Center
3803 Rectortown Road
Marshall, VA 20115
holly@raysmithlaw.com

Ryan L. Kelly
Kelly & Bramwell, P.C.
11576 South State Street Bldg. 1002
Draper, UT 84020
ryan@kellybramwell.com

Steve W. Chriss
Wal-Mart Stores, Inc.
2001 SE 10th Street
Bentonville, AR 72716-0550
stephen.chriss@wal-mart.com

Kurt J. Boehm, Esq.
Jody M. Kyler, Esq.
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
kboehm@BKLlawfirm.com
jkyler@BKLlawfirm.com

Brian W. Burnett, Esq.
CALLISTER NEBEKER &
MCCULLOUGH
Zions Bank Building
10 East South Temple, Suite 900
Salt Lake City, Utah 84133
brianburnett@cnmlaw.com

Stephen J. Baron
J. Kennedy & Associates
570 Colonial Park Drive, Suite 305
Roswell, GA 30075
sbaron@jkenn.com

Peter J. Mattheis
Eric J. Lacey
BRICKFIELD, BURCHETTE, RITTS & STONE, P.C.
1025 Thomas Jefferson Street, N.W.
800 West Tower
Washington, D.C. 20007
pjm@bbrslaw.com
elacey@bbrslaw.com

Gerald H. Kinghorn
Jeremy R. Cook
PARSONS KINGHORN HARRlS
111 East Broadway, 11 the Floor
Salt Lake City, UT 84111
ghk@pkhlawyers.com
jrc@pkhlawyers.com

Roger Swenson
US Magnesium LLC
238 North 2200 West
Salt Lake City, UT 84114-6751
roger.swenson@prodigy.net

Sophie Hayes
Sarah Wright
Utah Clean Energy
1014 2nd Avenue
Salt Lake City, UT 84111
sophie@utahcleanenergy.org
sarah@utahcleanenergy.org

Rob Dubuc
Western Resource Advocates
150 South 600 East, Suite 2A
Salt Lake City, UT 84102
rdubuc@westernresources.org

Steven S. Michel
Western Resource Advocates
409 E. Palace Ave. Unit 2
Santa Fe, NM 87501
smichel@westernresources.org

Nancy Kelly
Western Resource Advocates
9463 N. Swallow Rd.
Pocatello, ID 83201
nkelly@westernresources.org

Betsy Wolf
Salt Lake Community Action Program
764 South 200 West
Salt Lake City, Utah 84101
bwolf@slcap.org

Charles Johnson
1086 – 7B Pleasant Blvd.
Toronto, Ontario M4T1K2
cjohnson@ieee.org

Gloria D. Smith
Sierra Club
85 Second Street, Second floor
San Francisco, CA 94105
gloria.smith@sierraclub.org

Travis Ritchie
Sierra Club
85 Second Street, Second floor
San Francisco, CA 94105
travis.ritchie@sierraclub.org

Capt Samuel T. Miller
USAF Utility Law Field Support Center
139 Barnes Ave, Suite 1
Tyndall AFB, FL 32403
Samuel.Miller@Tyndall.af.mil

Lt Col Lance Thaxton
Civil Law Attorney
OO-ALC/JA
6026 Cedar Lane , Bldg 1278
Hill AFB, Utah 84056

Arthur Sandack
8 East Broadway, Ste 411
Salt Lake City, Utah 84111
asandack@msn.com

Bruce Plenk
2958 N St Augustine Pl
Tucson, AZ 85712
bplenk@igc.org

Janee Briesemeister
AARP
98 San Jacinto Blvd. Ste. 750
Austin, TX 78701
jbriesemeister@aarp.org

Randy N. Parker, CEO
Utah Farm Bureau Federation
9865 South State Street
Sandy, Utah 84070
rparker@fbfs.com

Leland Hogan, President
Utah Farm Bureau Federation
9865 South State Street
Sandy, Utah 84070
leland.hogan@fbfs.com

/s/_________________________________

BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 11-035-200

[Revenue Requirement]

Public Version

June 11, 2012

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 twenty-eight 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 125 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 at the Federal Energy Regulatory Commission.

OVERVIEW AND CONCLUSIONS

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

A. My testimony addresses certain revenue requirement issues in this general rate case. As part of my testimony, I make recommendations to adjust the revenue requirement proposed by Rocky Mountain Power ("RMP" or, as applicable, PacifiCorp). As I have not undertaken an exhaustive audit of all test period revenue, expenses, and other projections of RMP, absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What revenue increase is RMP recommending for the Utah jurisdiction?

A. In its direct filing, RMP is proposing a revenue increase of $172,267,339, or 9.7% percent on an annual basis. On April 30, 2012, RMP updated its net power costs, which has the effect of reducing net power costs allocated to Utah by approximately $8.7 million.

Q. Please summarize the revenue requirement adjustments you are recommending.

A. In total, my recommended revenue requirement adjustments reduce Utah revenue requirement by **$32,421,579**. These adjustments are presented in Table KCH-1 below. My recommended adjustments are as follows:

- RMP's revenue requirement should be adjusted to recognize the pro forma increase in wheeling revenue that RMP has requested at FERC and which is currently reflected in FERC interim rates. To the extent that a final rate determination by FERC differs from RMP's interim rates, this difference will be trued up through the EBA. The resulting impact from this adjustment is a **$1,296,677** reduction to the Utah revenue requirement.

- The annualized revenue increase attributable to Special Contracts 1 and 2 should be recognized as revenue in the determination of any test period revenue deficiency. The resulting impact from this adjustment, on a placeholder basis, is a **$1,281,085** reduction to the Utah revenue requirement. In addition, a rider surcredit should be established to recognize and credit to customers the incremental revenues attributable to Special Contracts 1 and 2, starting January 1, 2014 and running through the rate-effective date of the subsequent general rate case.
- I am recommending three adjustments related to the Klamath Hydroelectric Project: (1) increasing the amortization period for recovery of Klamath relicensing and settlement costs from seven and a half years (as proposed by RMP) to ten and a half years and limiting the forward-going carrying charges applied to these costs to RMP's long-term cost of debt (resulting in a reduction of **$2,603,881** to the Utah revenue requirement); (2) recognition of revenues for the cost of dam removal that are being contributed by Oregon and California customers in support of their respective state policies regarding this project (resulting in a reduction of **$7,445,474** to the Utah revenue requirement); and (3) denial of RMP's proposal to change the depreciation rate for this project (resulting in a reduction of **$2,261,847** to the Utah revenue requirement).

- RMP's property tax expense should be corrected by reducing RMP's pro forma adjustment by the amount of an error discussed in my testimony. The resulting impact from this correction is a **$3,582,565** reduction to the Utah revenue requirement.
- RMP's projection of its test year amount of wage expense should be adjusted to reflect an actual wage increase of 1.93% for the officer/exempt and non-exempt labor groups, rather than a projected target wage increase of 2.0% used in the Company's filing. The resulting impact from this adjustment is a **$50,859** reduction to Utah revenue requirement.
- The test year level of post retirement FAS 106 expense should be adjusted to reflect the impact of RMP's revised 2012 plan expense. The resulting impact from this adjustment is a reduction of **$189,104** to the Utah revenue requirement.
- RMP's non-labor O&M expense should be adjusted to remove the Company's projected cost escalation increase for the test period. The impact of this adjustment is a reduction of **$9,613,343** to the Utah revenue requirement.
- Wind O&M expense should be adjusted to reflect the normalized annual expense over the oil change cycle for wind plants. The impact of this adjustment is a reduction of **$599,714** to the Utah revenue requirement.
- The cost of certain extraordinary legal expenses and legal expenses that pertain exclusively to shareholder interests should be removed from the test period revenue requirement. The impact of this adjustment is a reduction of **$1,940,403** to the Utah revenue requirement.

- The cost of certain properties intended for future wind and transmission development should be removed from Plant Held for Future Use. The impact of this adjustment is a reduction of **$484,524** to the Utah revenue requirement.
- 67% of the contingency costs that RMP has built into its projected plant additions in this case should be removed from rate base. The impact of this adjustment is a reduction of **$453,569** to the Utah revenue requirement.
- An error in the allocation of certain costs associated with the Casper Service Center in Wyoming should be corrected. The resulting impact from this correction is a **$141,442** reduction to the Utah revenue requirement.
- RMP's Accumulated Deferred Income Tax balance should be increased by approximately $9.9 million relative to its filed case. The impact of this adjustment is a reduction of **$477,092** to the Utah revenue requirement.

Table KCH-1

Summary of Revenue Requirement Impact of UAE Adjustments

	Adjustment
Wheeling Revenue Adjustment	(1,296,677)
Special Contract Revenue Adjustment	(1,281,085)
Klamath Hydroelectric Settlement Amortization Expense Adjustment	(1,248,009)
Klamath Hydroelectric Settlement Rate Base Carrying Cost Adjustment	(1,355,872)
Klamath Surcharge Revenue Situs Adjustment	(7,445,474)
Klamath Hydroelectric Depreciation Expense Adjustment	(2,261,847)
Property Tax Expense Adjustment	(3,582,565)
Wage & Benefit Expense Adjustment - Wage Increase	(50,859)
Wage & Benefit Expense Adjustment - PBOP Update	(189,104)
O&M Expense Escalation Adjustment	(9,613,343)
Wind Turbine O&M Expense Adjustment	(599,714)
Legal Expense Disallowance Adjustment	(1,940,404)
Plant Held for Future Use Rate Base Adjustment	(484,524)
Contingency Cost Rate Base Adjustment	(453,569)
Casper Lease Buy-out Rate Base Allocation Correction	(141,442)
Accumulated Deferred Income Tax Update	(477,092)
Total UAE Test Period Adjustments	(32,421,579)

Q. Do you have any other recommendations?

A. Yes, given the challenges faced by exporters of Renewable Energy Credits ("RECs") in sustaining sales to California, I believe it is reasonable for the Commission to institute an incentive mechanism through which RMP can retain some direct benefit when its efforts to market RECs to California and other REC-consuming markets are successful. Specifically, I recommend that RMP be permitted to retain 10% of net REC revenues that are incremental to current projected test year sales; for sales beyond the test period, I recommend that RMP be permitted to retain 10% of net REC revenues that are incremental to committed future sales as of July 1, 2012. The incentive can be implemented through the REC Balancing Account.

WHEELING REVENUE

Q. Please explain your adjustment for wheeling revenue.

A. As discussed in the pre-filed direct testimony of Steven R. McDougal, RMP is in the midst of a transmission rate proceeding at FERC, in which the Company has filed updated wholesale rates for transmission and ancillary services provided under the Company's Open Access Transmission Tariff ("OATT").[1] According to Mr. McDougal, FERC issued an order August 8, 2011, accepting the filing, suspending it for a five-month period (subject to refund) and establishing hearing and settlement procedures.

As part of the FERC proceeding, RMP requested an increased revenue requirement, which, according to RMP, went into effect on an interim basis in January 2012.[2] RMP's new FERC rates include updated charges under Schedule 3 of the Company's OATT and a new Schedule 3A, which are designed to produce revenue to cover the cost of integrating third-party wind resources.

For Utah ratemaking purposes, RMP's projected FERC revenues are currently treated as a revenue credit applied to retail rates. If the revenue requirement increase requested by RMP at FERC is approved, it would cause a projected reduction in Utah test period revenue requirement of approximately

[1] Pre-filed direct testimony of Steven R. McDougal, lines 219-224.
[2] Ibid, lines 230-231.

$1.3 million.[3] However, because the FERC rate increase is still subject to settlement discussions and a final determination by FERC, RMP is proposing not to recognize any of this incremental Utah revenue credit in this general rate case, but rather to wait until a final FERC rate determination is made and to return the difference in revenue to Utah customers through the energy balancing account ("EBA") without application of the 30 percent sharing mechanism as an offset in the following ECAM filing.

I disagree with the Company's recommended approach. RMP's FERC filing purports to recover the Company's reasonable cost of service for wholesale transactions. Those rates are being recovered today through RMP's OATT, albeit on an interim basis. The most appropriate starting point for setting Utah rates using RMP's projected test period is to include the pro forma FERC revenue requirement proposed by RMP for that same period, rather than assuming zero incremental change as RMP has proposed. Even though the final rate may not be known for a period of time, projections should be used rather than assuming no rate change in light of RMP's use of a projected test period.

Q. What is your recommendation to the Commission?

A. RMP's revenue requirement should be adjusted to recognize the pro forma revenue increase that RMP has requested at FERC and which is currently reflected in interim rates. To the extent that a final rate determination by FERC differs from RMP's interim rates, this difference will be trued up through the EBA.

[3] Ibid, lines 259-261.

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

A. The resulting impact from my wheeling revenue adjustment is a **$1,296,677** reduction to the Utah revenue requirement. This adjustment is presented in UAE Exhibit RR 1.1.

SPECIAL CONTRACT REVENUES

Q. Please explain the basis for your adjustment for special contract revenues.

A. Special Contracts 1 and 2 are subject to rate increases, but on somewhat different terms than regular tariff customers. Special Contract 1 is subject to a rate increase on January 1, 2013 based on the average Utah base rate increase occurring over 2012. Special Contract 2 is subject to a rate increase on January 1, 2013 based on the Schedule 9 rate increase occurring during 2012.[4]

In filing a general rate case in Utah, RMP's standard treatment is to ignore this information – and to assume zero incremental revenues from these contracts – on the grounds that the final base rate increase in Utah in the measurement period (e.g., 2012) is not yet known.[5] This ratemaking assumption and the Company's rationale for it are unreasonable and should be rejected (unless of course this reasoning is similarly applied to the use of a projected test period as a general matter). By assuming, for ratemaking purposes, that any incremental revenue

[4] RMP Responses to UAE 2.6 and 2.7.
[5] Ibid.

from Special Contracts 1 and 2 is zero, the Company's revenue deficiency is overstated and the overall rate increase is greater than necessary.

Q. What is your recommended ratemaking treatment for the revenues from Special Contracts 1 and 2?

A. I recommend that the annualized revenue increase attributable to Special Contracts 1 and 2 be recognized as revenue in the determination of any test period revenue deficiency. For purposes of my testimony, I have calculated a placeholder value for this revenue based on RMP's requested revenue requirement. This value should ultimately be adjusted in a compliance filing based on the final revenue requirement approved by the Commission in this proceeding, as the benchmark rates used for adjusting Special Contract 1 and 2 rates are adjusted relative to the Company's filed case.

Because the January 1, 2013 rate increases for Special Contracts 1 and 2 are tied to Calendar Year 2012 base rate increases, I calculated the annualized revenue increase attributable to these contracts by multiplying their respective current revenues by the Company's requested percentage base rate increases scaled to 22.1%, which is the proportion of Calendar Year 2012 that is subject to a rate increase, i.e., the portion of the year occurring after October 12, the presumed rate-effective date for this case. The resulting revenues represent the going-forward annual revenues attributable to these two special contracts at RMP's requested overall revenue requirement starting January 1, 2013.

Q. What is the revenue requirement impact of your adjustment to special contract revenues?

A. The resulting placeholder impact from my special contract revenue adjustment is a **$1,281,085** reduction to the Utah revenue requirement. This adjustment is presented in UAE Exhibit RR 1.2.

Q. Because these contracts are structured such that their rate increases lag the rate increases for ordinary tariff customers, should there be further recognition of increased revenues from these contracts after January 1, 2014?

A. Yes. Currently, the lagging structure of these contracts is "gamed" in favor of RMP: the future special contract revenue is declared to be unknown by the Company, the revenue deficiency is thus overstated, other customers make up the shortfall, and the Company pockets the revenue increase when the lagged special contract revenue increase kicks in later. The fairest way to address this structural bias in the way RMP is attempting to set Utah rates is to recognize the incremental special contract revenues through a rider surcredit when they are recovered by RMP. In the case at hand, the rider surcredit should recognize and credit to customers the incremental revenues attributable to Special Contracts 1 and 2, starting January 1, 2014 and running through the rate-effective date of the subsequent general rate case.

KLAMATH HYDROELECTRIC PROJECT

Q. What are your adjustments relating to the Klamath Hydroelectric Project?

A. The Klamath Hydroelectric Project is a hydro generating facility consisting of eight developments in northern California and southern Oregon with an aggregate installed generating capacity of 169 MW. As explained in more detail below, RMP has entered a multi-party agreement, the Klamath Hydroelectric Settlement Agreement ("KHSA"), which creates a presumptive path for removal of the Klamath dams sometime after 2020.

I am recommending three adjustments related to the Klamath Hydroelectric Project: (1) increasing the amortization period for recovery of Klamath relicensing and settlement costs from seven and a half years (as proposed by RMP) to ten and a half years and limiting the forward-going carrying charges applied to these costs to RMP's long-term cost of debt; (2) recognition of revenues for the cost of dam removal that are being contributed by Oregon and California customers in support of their respective state policies regarding this project ; and (3) denial of RMP's proposal to change the depreciation rate for this project.

Q. What is the KHSA?

A. The KHSA is an agreement between PacifiCorp and over two dozen other parties that was signed on February 28, 2010. The agreement resulted from PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA followed a non-binding Agreement in Principle signed in 2008 by PacifiCorp, the

U.S. Secretary of the Interior, and the Governors of Oregon and California that established a framework for a final settlement agreement that would provide a presumptive path to dam removal no earlier than 2020. To the best of my knowledge, neither the State of Utah nor any representatives of Utah interests participated in the negotiation process or the agreements.

The KHSA provides for the transfer of the Klamath Hydroelectric Project to a dam removal entity no earlier than 2020. The U.S. Secretary of the Interior is to conduct further studies and environmental review and was required to make best efforts to determine by March 31, 2012 whether dam removal should proceed. Prior to this determination, federal legislation must be enacted to implement key provisions of the KHSA and to protect PacifiCorp and its customers from liabilities related to dam removal.

Q. Have these federal milestones been met?

A. No. The March 31, 2012 date has passed without passage of the requisite Federal legislation and without the requisite finding by the Secretary of the Interior that dam removal should proceed.

Q. What is the status of the attempts to reach these milestones?

A. According to RMP, bills were introduced to the U.S. House of Representatives and Senate in November 2011, but they have not been enacted.[6] The Company also indicates that the study and environmental review process is substantially complete and that a Draft Environmental Impact

[6] Direct testimony of Andrea L. Kelly, lines 807-821.

Statement/Environmental Report was issued by the U.S. Department of the Interior and the California Department of Fish and Game on September 21, 2011.[7]

Q. Are there additional milestones that warrant consideration?

A. Yes. Significant funding will be required for removal to proceed per the terms of the KHSA. To that end, $200 million of funding from Oregon and California customers has been approved by those states' regulatory commissions. However, a second major funding source, up to $250 million in bonds (or other financing) to be issued by the State of California, has yet to be enacted. According to RMP, approval of a bond measure covering California's additional contribution to these costs will be on the ballot in that state in November 2012.[8]

Q. What special cost recovery is RMP seeking with respect to the KHSA and the Klamath Hydroelectric Project in this proceeding?

A. There are several categories of costs that RMP seeks to recover in this case:

- The costs of relicensing and settlement, projected to be $81.8 million system-wide, which RMP proposes to include in rate base and amortize over seven and a half years. Utah's annual share of this cost is approximately $8.9 million.[9]

---

[7] Ibid, lines795-802.
[8] Source: Wyoming Docket No. 20000-405-ER-11, RMP Response to WIEC Data request 25.7.d, which is included in UAE Exhibit 1.17.
[9] Approximately $4.7 million in amortization expense plus $4.2 million in return on rate base.

- Cost of dam removal. Under the 2010 Protocol, this cost is situs assigned to Oregon and California. Under the Rolled-in method, Utah is allocated a share of this cost.
- Accelerated depreciation of the existing Klamath Hydroelectric Project assets and all new Project assets to coincide with the December 31, 2019 removal date anticipated in the KHSA.

I note that each of these issues was raised in the prior rate case, Docket No. 10-035-124, and were ultimately addressed in the Stipulation approved in that docket as the "Klamath Postponement" adjustment. The stipulating parties agreed, for purposes of that case only, that (a) existing plant assets associated with the Klamath Hydroelectric Project would continue to be depreciated using previously-approved depreciation schedules; (b) issues relating to the KHSA would be postponed to a future proceeding; and (c) RMP could continue to defer relicensing and settlement process costs and record a carrying charge based on the AFUDC rate, but that such deferral would not be amortized or included in rate base unless ordered by the Commission in a future proceeding. Parties remained free to present any proposed adjustments to cost recovery associated with the KHSA in future cases.

Q. Please explain your adjustment concerning the costs of relicensing and settlement.

A. The history of the Company's relicensing and settlement experience is recounted in the direct testimony of RMP witness Andrea L. Kelly.[10] As discussed by Ms. Kelly, PacifiCorp decided to enter the KHSA because the Company believed it to be in the best interest of customers compared to the alternative of relicensing under a range of possible outcomes. In this proceeding, RMP is seeking to establish a regulatory asset of $81.8 million (total Company) associated with relicensing and settlement costs. As noted above, this regulatory asset would be added to rate base and amortized over seven and a half years. Of the $81.8 million RMP is seeking to add to rate base, approximately $48.5 million is comprised of direct expenditures incurred by the Company and $33.3 million consists of AFUDC that has accrued on these expenditures.

Based on the presumptions that these relicensing costs were prudently incurred by RMP and that a pro rata share of the same should be allocated to Utah ratepayers, my proposed adjustment would allow for full amortization of the relicensing and settlement costs incurred by RMP, including past accrual of AFUDC. However, my adjustment would limit the forward-going carrying charges on this regulatory asset to the Company's long-term cost of debt. I believe this treatment is appropriate given the nature of the costs being recovered.

Q. Please explain.

A. The Company's expenditure on relicensing and settlement costs cannot reasonably be construed to contribute, directly or indirectly, to the provision of electric service to Utah customers. Rather, these expenditures have culminated in

[10] Direct testimony of Andrea L. Kelly, lines 274-419.

an agreement to do just the opposite – to eliminate a valuable resource from the Company's generating fleet. While the Company has presented an analysis that justifies the costs it has incurred as part of the relicensing process and its decision to enter the KHSA, the fact remains that these expenditures are not investments intended to provide benefits or service to customers. Accordingly, it is not reasonable for Utah customers to pay RMP a return on these expenditures that is comparable to the return on investment in an asset that is used and useful in the provision of electric service. Instead, recovery of the expenditures plus a carrying charge equal to the cost of long-term debt is a more appropriate cost recovery treatment. This approach would fully reimburse the Company for its costs plus a reasonable cost of capital without unjustly enriching the Company, which is what would occur if it were rewarded with a return on equity on this "non-asset." I note that over 40 percent of the proposed regulatory asset is comprised of accumulated carrying costs (AFUDC) dating back to 1998, applied to the Company's actual out-of-pocket expenditures, which is not diminished by my adjustment. This is further evidence that my recommendation treats the Company fairly.

Q. Please explain the basis of your recommendation to amortize these costs over ten and a half years.

A. The relicensing and settlement costs were incurred over a twelve-year period and pertain to an asset with a potentially long remaining life (absent the commitment to dam removal). Because of the long-term nature of the costs incurred and the underlying asset, it is reasonable to amortize these costs over a comparably long period to reflect this time horizon and to mitigate the rate impact on customers. I believe ten and a half years is appropriate for this purpose. (My recommended amortization period adds exactly three years to the Company's recommended ending date of December 2019.) Whereas in most instances, amortization periods can be selected that are reasonably aligned with the receipt of customer benefits from the underlying expenditures, that is not possible in this circumstance as there is no discernible stream of benefits to Utah ratepayers with which to align.

Q. What is the revenue requirement impact of your recommended treatment of relicensing and settlement cost recovery?

A. This adjustment is presented in UAE Exhibit RR 1.3 and 1.4. The extension of the amortization period to ten years reduces RMP's Utah revenue requirement by **$1,248,009** and the adjustment to the rate of return reduces it by a further **$1,355,872**.

Q. Please explain your adjustment concerning cost of dam removal.

A. Using the Rolled-in cost allocation method, RMP allocates Utah a share of dam removal costs. This allocation of $7.4 million is shown in RMP Exhibit SRM-2, p. 8.11. At first consideration, it would be reasonable disallow recovery of these costs in this case because they are not yet being incurred. However, it is important to note that Oregon and California customers, consistent with the support of their respective state governments, including utility regulators, for dam removal, have become obligated to pay up to $200 million to fully cover RMP's maximum exposure to the costs for this project. Yet, RMP's Rolled-in allocation to Utah does not recognize these revenues being contributed by Oregon and California customers to pay for dam removal. I do not believe this omission is reasonable. These special customer contributions are being made in furtherance of Oregon and California state policies to remove this RMP system resource. Therefore, it is appropriate for the revenues being recovered from these customers to be recognized as an offset to the cost of removal allocated to Utah.

Although it would be reasonable to deny recovery of Utah's share of the cost of removal at this time because it is premature, recognition of the revenues contributed by Oregon and California customers renders such an adjustment unnecessary. Therefore, I recommend that RMP's revenue requirement in this case be adjusted to recognize a revenue credit attributable to the contributions committed from Oregon and California customers to fully fund RMP's maximum obligation for the cost of removal. This adjustment exactly offsets the cost of removal allocated to Utah by RMP.

As shown in UAE Exhibit RR 1.5, this adjustment reduces RMP's Utah revenue requirement by **$7,445,474**.

Q. What is your recommendation to the Commission with respect to RMP's proposed change in depreciation rates?

A. I recommend that the Commission deny RMP's proposal to adjust the depreciation rates for the Klamath Hydroelectric Project assets at this time. The proposal is premature because the reality and timing of dam removal under the KHSA is speculative and uncertain. As noted above, the proposed removal of the Klamath Hydroelectric Project dams requires that certain milestones be met, including the passage of federal legislation. The federal legislation has yet to occur, and very possibly may never occur. In addition, significant funding will be required for removal to proceed per the terms of the KHSA. Whereas $200 million of funding from PacifiCorp's Oregon and California ratepayers has been approved by those states' regulatory commissions, a second major funding source, up to $250 million in bonds (or other financing), which must be issued by the State of California, has yet to be approved or enacted. In light of the uncertainty as to whether or when dam removal will actually proceed, I believe it is premature to change the depreciation rates for the Klamath Hydroelectric Project assets at this time. Moreover, even if this adjustment were not premature, it is not clear that the cost of accelerated recovery of an asset that has not been providing full benefits to Utah ratepayers over its service life should be fully allocated to Utah.

Q. What is the revenue impact of your recommendation to deny the proposed adjustment to the Klamath Hydroelectric Project depreciation rates?

A. As shown in UAE Exhibit RR 1.6, this adjustment reduces RMP's Utah revenue requirement by **$2,261,847**.

PROPERTY TAX EXPENSE

Q. Please explain your adjustment to property tax expense.

A. In preparing its case, RMP inadvertently used a base year property tax expense that was understated by $8.3 million.[11] As a result, RMP overstated the change in property tax expense required to reach its projected expense level. RMP then added the incorrect change in property tax to the actual base property tax amount, causing an overstatement in the Company's projection in test period revenue requirement corresponding to Utah's share of the error. The admission of this error is documented in Wyoming Docket 20000-405-ER-11, and it is equally applicable to Utah. See RMP Response to WIEC Data Request 29.7, which is included in UAE Exhibit RR 1.17.

Q. What is your recommended adjustment for property tax?

A. RMP's property tax expense should be corrected by reducing RMP's pro forma adjustment by the amount of the error discussed above.

Q. What is the revenue requirement impact of the adjustment to property tax expense?

A. The resulting impact from of this adjustment is a **$3,582,565** reduction to Utah revenue requirement. The impact of this adjustment on net operating income is shown in UAE Exhibit RR 1.7.

[11] Exhibit RMP__(SRM-3), p. 7.2.1 and p. 9.17.

WAGE AND BENEFITS EXPENSE

Q. Do you have any recommended adjustments to RMP's proposed wage and benefit expenses?

A. Yes, I recommend two adjustments to RMP's wage and benefit expenses. These adjustments pertain to the following categories:

- Wage increase expense
- Post-Retirement Benefits – FAS 106

Q. Please describe your adjustment to RMP's wage increase expense.

A. At the time of its filed case, RMP's projection of its test year amount of wage expense included a January 2012 target wage increase of 2.0% for the officer/exempt and non-exempt labor groups. However, the actual wage increase granted to these labor groups was slightly less, 1.93%. This is documented in the Company's Response to UAE Data Request 3.4 and OCS Data Request 8.18. My recommended adjustment reflects the application of the actual wage increase instead of RMP's projected escalation.

Q. What is the revenue requirement impact of your adjustment to wage increase expense?

A. The resulting impact from my wage increase expense adjustment is a **$50,859** reduction to Utah revenue requirement. This adjustment is shown in UAE Exhibit RR 1.8.

Q. Please explain your adjustment to the post retirement benefits – FAS 106 expense.

A. I recommend adjusting the test year level of post retirement FAS 106 expense to reflect the impact of RMP's revised 2012 plan expense. In its response to OCS Data Request 6.12, RMP recalculated its 2012 plan expense to include the effect of actual 2011 asset and claims experience that became known during the course of this proceeding. This revision to RMP's 2012 plan expense produces an overall test year post retirement benefit-FAS 106 expense amount of $1,066,713, as compared to $1,866,747 in the Company's direct filing.

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

A. As shown in Table KCH-1, my recommendation reduces RMP's Utah revenue requirement by **$189,104**. The impact of this adjustment on net operating income is shown in UAE Exhibit RR 1.9.

O&M COST ESCALATION

Q. What adjustment are you proposing with respect to non-labor O&M expense?

A. I am proposing an adjustment to remove the inflation escalator applied by RMP to its test period non-labor O&M expense.

Q. Please explain the basis for your adjustment.

A. The non-labor O&M expense projected by RMP for the test period contains a cost escalation component to reflect projected inflation for the period extending from July 2011 through May 2013. To apply this cost escalator, RMP starts with its actual non-labor O&M expense for the base period, July 2010 to

June 2011. RMP then applies a series of escalation factors to the base-period cost of its materials and services using indices for electric utility costs produced by Global Insight.

From a ratemaking perspective, I have two serious concerns with this approach.

First, at a broad policy level, I have concerns as an economist about regulatory pricing formulations that reinforce inflation. This occurs when *projections* of inflation are built into formulas that are used to set administratively-determined prices, such as utility rates. Such pricing mechanisms help to make inflation a self-fulfilling prophesy. As a matter of public policy, this is a serious concern. It is one thing to adjust for inflation after the fact; it is another to help guarantee it. For this reason, I believe that regulators should use extreme caution before approving prices that guarantee inflation before it occurs.

Q. What is your second major concern?

A. A related, but distinct, concern involves the building of this "cost cushion" into the Company's test period costs. Allowing this type of systemic uplift in rates goes well beyond the basic rationale advanced by advocates for using a projected test period, which is to ameliorate the effect of regulatory lag on the recovery of investment in new plant. The best evidence of what it costs RMP for non-labor O&M is the Company's actual costs recorded in the base period. The cost increases represented by the escalation factors may or may not come to fruition. In any case, RMP should be expected to strive to improve its O&M efficiency on a continuous basis, and thereby lessen the net impact of inflation on its O&M costs. It is not reasonable to simply gross up the Company's actual base period costs by an index factor and pass these costs on to customers.

Q. Can you provide a specific example of how RMP's approach creates a cost cushion for the Company?

A. Yes. Later in my testimony I discuss in some detail (and recommend a disallowance for) certain legal expenses incurred by the Company. Legal expenses are among the numerous base period expense items that the Company simply grosses up for inflation and seeks to recover in the test period. As shown in Confidential UAE Exhibit 1.18, the Company's legal expenses in the base year [redacted],[12] and as I discuss later, at least one large expense item should be viewed as extraordinary and unlikely to be repeated. [redacted].[13] [redacted]; instead, the extraordinary level of base year expense is further inflated by the Company's escalation factors to derive the projected test period expense level. This is a good example of the cost

[12] Oregon PUC Docket UE-246, Confidential Attachment ICNU 2.36, p. 17, included in Confidential UAE Exhibit 1.18.
[13] Oregon PUC Docket UE-246, Confidential Attachment ICNU 2.28, included in Confidential UAE Exhibit 1.18.

cushion that is created by the Company's approach of using indexed cost escalators.

Q. Are there ever situations in which inflation should be considered in this context?

A. Yes. The United States experienced major inflation during the late 1970s. In that type of severe increasing-cost environment, some consideration for O&M inflation in a projected test period would probably be necessary. However, we are very far from such a cost environment. Inflation in the United States has been at very low levels for several years. While world events have caused recent spikes in some energy and food prices, the prospects for core inflation, which excludes these two relatively volatile pricing components, remain subdued.

Q. Can you cite to any independent sources to support your contention that the prospects for core inflation remain subdued?

A. Yes. I have reviewed the Minutes of the Federal Reserve Open Market Committee for April 24-25, 2012. The published Minutes of that meeting indicate that the Fed's central tendency forecast for core inflation is in the range of 1.8% to 2.0% for 2012 and 1.7% to 2.0% for 2013. The January 2012 forecast of the Congressional Budget Office for core inflation is even milder, at 1.2% to 1.4% in 2012 and 1.4% to 1.6% in 2013.

Q. What alternative for establishing non-labor O&M expense for the projected test year do you recommend?

A. I recommend adjusting RMP's non-labor O&M expense to remove its projected cost escalation increase for the test period. The impact of this adjustment is shown in UAE Exhibit RR 1.10.

Q. Are there any exceptions to your removal of projected inflation from RMP's test period expense?

A. Yes. For a number of line items, such as the Electric Lake Settlement, Powerdale Hydro removal, and Utah automated reading, RMP has projected test period O&M expense on a standalone basis and compared that result to the inflation-adjusted result (i.e., the base period actual expense multiplied by the cost escalation factor) for the same line item. The Company then performs an adjustment that effectively replaces the inflation-adjusted line item forecast with the standalone line-item forecast that appears to exclude inflation. For these line items, I have reversed my escalation adjustment.

For another set of line items – thermal O&M, wind/hydro O&M, and Klamath O&M – RMP also projects test period O&M expense on a standalone basis and compares that result to the inflation-adjusted result for the same line item. Similarly, the Company then performs an adjustment that effectively replaces the inflation-adjusted line item forecast with the standalone line-item forecast. However, for these line items, it is not at all clear that the standalone forecast excludes inflation. In fact, for certain line items (e.g., Klamath O&M, thermal O&M for plants owned by others) inflation is clearly built into the standalone forecast;[14] that is, the Company has replaced the generic Global Insight inflation forecast with a line-item-specific inflation forecast. Consequently, I have not reversed my O&M escalation adjustment for this set of line items (i.e., thermal O&M, wind/hydro O&M, and Klamath O&M).

This matter is still the subject of outstanding discovery. If, based on the forthcoming responses I determine that there are additional line-item cost projections that are based on base period input prices that do not reflect input price escalation, I will supplement my testimony to adjust my O&M escalation adjustment and reverse my adjustment for the affected line item(s).

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

A. This adjustment is presented in UAE Exhibit RR 1.10. It reduces Utah revenue requirement by **$9,613,343**.

WIND O&M EXPENSE

Q. Please explain your proposed adjustment to Wind O&M Expense.

A. As discussed in the direct testimony of Mark R. Tallman, routine oil changes will be performed at nine of RMP's thirteen wind projects during the test period and the Company has included the projected expense for these projects in its test period revenue requirement.[15] The problem with the Company's approach is that the oil change schedule is heavily weighted in the test period and does not

[14] RMP Response to OCS 8.32, Confidential Attachment 8.32-2; RMP Response to OCS 8.13, Confidential Attachment OCS 8.13a.

reasonably reflect a normalized annual expense for this activity. I recommend adjusting the Wind O&M expense to reflect the normalized annual expense over the oil change cycle.

Q. Has RMP recognized this issue in any other recent proceedings?

A. Yes. In Wyoming Docket No. 20000-405-ER-11, WIEC witness Randall Falkenberg recommended normalizing the Company's oil change expense. In the Company's Rebuttal testimony filed May 25, 2012, RMP adopted Mr. Falkenberg's recommendation, modifying it slightly to incorporate the oil change expenses of the Dunlap I wind project. This same change should be adopted in Utah.

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

A. This adjustment is presented in UAE Exhibit RR 1.11. It reduces Utah revenue requirement by **$599,714**.

LEGAL EXPENSE

Q. Please explain your adjustment to legal expense.

A. The legal expense embedded in RMP's proposed revenue requirement for the test period is based on the Company's actual base period expenses escalated by an inflation factor. As discussed above, I have already removed the inflation factor applied to these expenses. However, a further adjustment is required because PacifiCorp incurred a number of extraordinary legal expenses in the base

[15] Direct testimony of Mark R. Tallman, lines 95-98.

period that should be removed to attain a more representative annual expense. In addition, the Company has incurred certain legal expenses that pertain exclusively to shareholder interests and should not be recovered from customers in rates. These expenses should be removed as well.

Q. Which legal expenses should be removed on the basis that they are extraordinary?

A. As shown in Confidential UAE Exhibit RR 1.18, PacifiCorp incurred very substantial legal expenses in the base period on a single case, Wah Chang vs PacifiCorp, which involves a dispute dating back to 2000 over the terms of a special tariff that was approved by the Oregon Public Utilities Commission ("OPUC"). While the legal dispute has extended over several years, the [redacted].[16]

Q. What did this case concern?

A. According to PacifiCorp's 10K, filed in February 2012, Wah Chang, a large industrial customer, filed an action before the OPUC asserting that the rates set by the special tariff were not just and reasonable due to alleged market manipulation during the energy crisis. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for

---

[16] Oregon PUC Docket UE-246, Confidential Attachment ICNU 2.36, p. 8, included in Confidential UAE Exhibit 1.18.

Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon granted Wah Chang's motion for review and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief. In July 2010, the Oregon Court of Appeals accepted judicial review.

In a separate but related proceeding, Wah Chang also filed a complaint in December 2000 in the Circuit Court for Linn County, Oregon asserting that the special tariff with PacifiCorp was subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In April 2011, Wah Chang's claims were presented during a jury trial, and all claims, including the claim for punitive damages, were resolved in PacifiCorp's favor. Wah Chang did not appeal this outcome.

Given the completion of this latter proceeding and the unique nature of Wah Chang proceedings, it is reasonable to assume that the exceptionally-high base-period level of expenses associated with that case are unlikely to be repeated in the test period. Because these expenses are extraordinary, they should not be included as representative of going-forward legal expense.

Q. Are there other reasons why these costs should be disallowed?

A. Yes. RMP allocated these costs using the SO factor. As this case involves the interpretation of the terms of the Company's Oregon retail tariff, there is not a reasonable basis for allocating these costs to other jurisdictions such as Utah. Thus, even if these expenses were not extraordinary, there is not a good reason for them to be allocated to the Utah jurisdiction in the first instance.

Q. What legal expenses are you recommending be disallowed for recovery because they pertain exclusively to shareholder interests?

A. The expenses concern three cases: (1) USA Power v. Jody L. Williams et al; (2) Deseret Power Electric Co-op (Hunter 2); and (3) Deseret Power Electric Co-op (Turbine).

The USA Power case involves a complaint filed in Utah's Third District Court[17] alleging, among other things, that in developing its Currant Creek generating facility, PacifiCorp breached a confidentiality and non-disclosure agreement with USA Power and misappropriated trade secrets of USA Power. On May 21, 2012, a Utah jury found in favor of USA Power and awarded the plaintiff nearly $134 million in damages, finding, among other things, that PacifiCorp's misappropriation of USA Power's trade secret was "willful and malicious." PacifiCorp has indicated it will appeal the verdict, so further substantial legal expenditures are sure to follow.

Q. Why are you recommending disallowance of these expenses?

A. There is no stretch of reasoning by which the legal expenses incurred to defend PacifiCorp in the USA Power case can be construed to be a customer responsibility. One of the Utah jury findings against PacifiCorp was that of "unjust enrichment." The cost of defending the conduct of the Company's management against claims of unjust enrichment in a case such as this is entirely a shareholder responsibility. PacifiCorp's legal defense in this type of case should not be underwritten by customers under any circumstances.

Q. What is your understanding of the nature of the litigation with Deseret Power?

A. Deseret and PacifiCorp are two of three joint owners of the Hunter Unit 2 power plant that is operated by PacifiCorp pursuant to contract. As I understand it, the contract between Deseret and PacifiCorp requires PacifiCorp to obtain Deseret's consent before making capital improvements above a certain cost. In the absence of such consent, PacifiCorp can submit the matter to arbitration and proceed with the capital improvement at its own risk and expense. If the arbitrator determines that the capital improvement was consistent with reasonable utility practice as defined by the contract, Deseret is required to pay its share of the contested capital expenses. If the arbitrator determines that the capital improvement was not consistent with reasonable utility practice, Deseret is not required to pay its portion of the contested expenses.

Q. With respect to the Deseret-related legal expenses that you recommend be disallowed, what capital projects were at issue?

A. As I understand it, there were two separate arbitration hearings involving three capital improvement projects at Hunter Unit 2. The first hearing involved a

[17] Case No. 050903412.

scrubber upgrade and a conversion of Hunter Unit 2's electrostatic precipitator to a baghouse. The second arbitration hearing involved a turbine rotor upgrade.

Q. What were the results of the arbitration hearings?

A. I understand that the arbitrator in the first hearing found that the scrubber upgrade was not consistent with reasonable utility practice, but that the baghouse conversion was. In the second hearing, my understanding is that the arbitrator found that that rotor upgrade was not consistent with reasonable utility practice.

Q. Is your recommendation for disallowance of the legal costs associated with these disputes based upon the fact that PacifiCorp lost on two of the three issues?

A. No, although I think the outcome of the litigation is relevant. A finding by an arbitrator that PacifiCorp did not act consistent with reasonable utility practice suggests imprudence. However, my recommendation extends to costs associated with litigation on the two issues on which PacifiCorp lost as well as the one issue on which it won.

Q. Please explain.

A. This type of contract litigation with co-owners of a plant is for the benefit or detriment of PacifiCorp and its owners, not its ratepayers. Perhaps the easiest way to illustrate this point is to consider that PacifiCorp's ratepayers do not benefit from a PacifiCorp win in the arbitration – a win simply means that Deseret will pay for a share of the capital costs associated with its ownership in the plant – and PacifiCorp's ratepayers do not suffer if PacifiCorp loses – a loss means that

PacifiCorp is required under its operating contract to pay for the co-owner's share of expenditures determined not to be consistent with reasonable utility practice. Capital expenditures associated with an upgrade to a portion of the plant owned by another utility cannot properly be passed on to PacifiCorp's ratepayers. PacifiCorp's ratepayers do not receive value from a portion of the plant owned by another company, and cannot properly be asked to pay capital costs or other expenses associated with that portion. Because ratepayers do not stand to gain or lose from the outcome of this type of litigation, it follows that they cannot properly be expected to pay the legal costs associated with the litigation, regardless of the outcome.

Q. Are you saying that legal costs associated with litigation with co-owners can never properly be considered in Utah rates?

A. No, any such litigation would have to be evaluated on its own merits under the relevant circumstances. Where, as here, the litigation involves PacifiCorp's alleged contractual failure as operator of a plant to act in a manner consistent with reasonable utility practice vis-à-vis a portion of the plant owned by another company, and where ratepayers do not stand to gain or lose from the outcome, the legal expenses should be borne by PacifiCorp and not its ratepayers.

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

A. This adjustment is presented in Confidential UAE Exhibit RR 1.12. It reduces Utah revenue requirement by **$1,940,404**.

PLANT HELD FOR FUTURE USE

Q. Please explain your adjustment to Plant Held for Future Use

A. RMP holds certain properties in rate base classified as Plant Held for Future Use ("PHFU") in anticipation of their future use. While it is arguable that all such costs should be disallowed at this time because this plant is not (yet) used and useful, and may never be, PHFU treatment of certain properties is more questionable than others when time horizon and probability of use are taken into account. In particular, RMP recently agreed in Wyoming that it would be appropriate to remove $8.9 million in PHFU associated with the Twelve Mile Wind Farm and the Wild Horse Wind Farm, which are not slated for development until 2021 and 2022, respectively. The Company also agreed to remove PHFU associated with three transmission projects (Aeolus Substation, Anticline Substation, and Populus Substation - Bastion Property) which are not slated for development until the 2018 to 2021 time horizon.

I recommend that at a minimum, comparable adjustments to remove this plant from PHFU in Utah should be adopted.

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

A. This adjustment is presented in UAE Exhibit RR 1.13. It reduces Utah revenue requirement by **$484,524**.

CONTINGENCY COSTS

Q. Does RMP include a contingency amount when estimating plant additions for a future test period?

A. Yes. According to RMP's Response to UAE 4.1, the Company includes contingency costs on certain projects costing more than $10 million.

Q. How does RMP determine what amount of contingency cost to include when estimating the cost of plant additions?

A. According to RMP's Response to UAE 4.4, when necessary, project cost estimates include a contingency estimate to reflect identified risks such as the length of the construction period; the complexity associated with the project; and unforeseen and unpredictable conditions, such as weather and soil conditions, and uncertainties within the defined project scope such as commodity prices.

Q. Please explain the basis for your adjustment to contingency costs.

A. One of the challenges in using a future test period is to ensure that the amount of projected plant additions is accurate. This challenge can be exacerbated when projections of plant additions include a contingency factor. Including a contingency factor may make sense when managing a construction budget for any particular project; however, it does not necessarily follow that including the sum of contingency costs for all major projects is reasonable from a ratemaking perspective. It is one thing to have some room in the construction budget for a given project in case something goes wrong; it is another thing to charge ratepayers for projected rate base that assumes that something goes wrong for every major project that is carrying a contingency component. To do so is to ensure that customers are overcharged.

Projected test periods are still relatively recent in Utah. UAE asked RMP to identify the amount of contingency included in plant additions in the two previous rate cases and to identify, on an after-the-fact basis, the amount of contingency that was ultimately unused. In Docket No. 10-035-124, the unused contingency was approximately 64%.[18] In Docket No. 09-035-23, the unused contingency was approximately 76%.[19] The weighted average across the two cases was 67%.

Using this information on past outcomes as a guide, I adjusted the contingency cost that RMP included in the current case by removing 67% of the contingency amount for the thirteen plant additions that RMP identified as carrying a contingency component.

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

A. This adjustment is presented in UAE Exhibit RR 1.14. It reduces the Utah revenue requirement by **$453,569.**

CASPER SERVICE CENTER LEASE BUYOUT

Q. Please explain your adjustment to the Casper Service Center lease buyout.

A. RMP has included in the test year a pro forma general plant addition associated with a buyout of its Casper Service Center lease in the amount of

[18] RMP Response to UAE 4.5, Attachment 4.5.
[19] RMP Response to UAE 4.6, Attachment 4.6.

$2,950,000 on a total Company basis. RMP's filing allocates this rate base item on the SO factor, with $1,264,181 allocated to the Utah jurisdiction. As explained in RMP's response to OCS Data Request 8.26(d), this allocation was in error. The Casper Service Center Lease Buy-out should properly be situs assigned to Wyoming. My adjustment corrects this error.

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

A. This adjustment is presented in UAE Exhibit RR 1.15. It reduces the Utah revenue requirement by **$141,442.**

ACCUMULATED DEFERRED INCOME TAXES

Q. What adjustment are you recommending regarding accumulated deferred income taxes ("ADIT")?

A. In Response to Confidential OCS Data Request 26.1, RMP indicates that the Company is in a position to increase its ADIT balance by approximately $9.9 million relative to its filed case. I recommend adopting this adjustment, which has the effect of reducing rate base.

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

A. This adjustment is presented in UAE Exhibit RR 1.16. It reduces the Utah revenue requirement by **$477,092.**

REC INCENTIVE

Q. How are sales of RECs handled for ratemaking purposes in Utah?

A. One hundred percent of projected REC sales in the test period are credited to customers. The projected REC sales are then trued up to actual through the REC Balancing Account ("RBA") for later refund or credit, with the balance earning a carrying charge equal to the long-term cost of debt. The RBA is a recent development, having been adopted as part of the Stipulation approved in the last general rate case, Docket No. 10-035-124.

Q. Did UAE support the adoption of the RBA?

A. Yes. The RBA is a reasonable means to ensure proper recognition of REC revenues in rates, particularly in light of the potential for large swings in the level of REC revenues.

Q. What is RMP projecting with respect to sales of RECs?

A. As discussed in the direct testimony of Stefan Bird, the Company's REC sales projections have declined significantly relative to recent years. REC revenues in last general rate case were $86.1 million on a total Company basis, $50.9 million of which was allocated to Utah. In the current case, the Company has forecast test period REC revenues of $42.2 million, $25 million of which is Utah-allocated. Mr. Bird attributes this decline to limited market opportunities driven by increasing restrictions in the California RPS market, and the expiration of existing contracts for structured, bundled RECs.

Q. Do you recommend any going forward changes to the ratemaking treatment of RECs in Utah?

A. Yes. Given the challenges faced by REC exporters in sustaining sales to California, as described by Mr. Bird, I believe it is reasonable for the Commission to institute an incentive mechanism through which the Company can retain some direct benefit when its efforts to market RECs to California and other REC-consuming markets are successful. I am concerned that the impediments to successful REC sales in the current market may discourage utilities without a direct upside from participating in the REC market to the fullest extent possible going forward. A properly-constructed incentive mechanism can ensure that shareholder and ratepayer interests are properly aligned and that the Company is sufficiently motivated to pursue prudent REC sales for the benefit of both interests.

Q. What specific incentive mechanism are you proposing?

A. I recommend that RMP be permitted to retain 10% of net REC revenues that are incremental to current projected test year sales; for sales beyond the test period, I recommend that RMP be permitted to retain 10% of net REC revenues that are incremental to committed future sales as of July 1, 2012.

Q. How should the REC incentive mechanism be implemented?

A. It can be incorporated into the RBA. In this rate case, to the extent that actual REC sales exceed projected test period sales, the RBA will accrue a positive balance (i.e., credit to customers). The incentive to RMP can be paid from this balance. In future rate cases, the 90/10 sharing can be applied to incremental REC sales (as defined above) as part of setting base rates, with any differences captured in the RBA true up.

Q. In the EBA proceeding, you recommended a 70/30 sharing mechanism for net power costs. Why are you recommending a different sharing percentage for RECs?

A. The 70/30 sharing mechanism in the EBA is applied to *deviations* from base net power costs in rates, whereas the 90/10 sharing arrangement I am recommending for RECs would be applied to *all* incremental REC sales; thus, the sharing percentage is applied to an entirely different basis. Given the difference in basis for the application of the sharing percentages, the use of different sharing percentages is entirely appropriate.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UAE Exhibits RR 1.1 – 1.18

[Redacted; Public Version]

Docket No. 11-035-200

[Revenue Requirement]

Rocky Mountain Power

Utah Retail Operations
UAE Wheeling Revenue Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Wheeling Revenue (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	1,294,640
6	Total Operating Revenues	1,294,640
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	432,495
24	Income Taxes - State	58,769
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	491,264
29		
30	Operating Rev For Return:	803,376
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	6,627
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	6,627
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	6,627
	UTAH REV. REQ'T CHANGE	(1,296,677)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wheeling Revenue Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= \$6,627 x 7.906% x 1.6151
≈ \$846

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wheeling Revenue Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= (\$803,376) x 1.6151
≈ (\$1,297,523)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Wheeling Revenues Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Revenues:					
Annual Third Party Transmission Revenues	456	1,300,000	SG	43.155%	561,011
Annual Ancillary Services Revenues	456	1,700,000	SG	43.155%	733,630
Total Adjustment to Revenues:		3,000,000			1,294,640

Data Source:
1. Direct Testimony of Stven R. McDougal, p. 11, lines 253-254.

Rocky Mountain Power

Utah Retail Operations
UAE Special Contract Revenue Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Special Contract Revenue (B)
1	Operating Revenues:	
2	General Business Revenues	1,278,811
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	1,278,811
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	427,207
24	Income Taxes - State	58,050
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	485,258
29		
30	Operating Rev For Return:	793,553
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	6,546
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	6,546
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	6,546
	UTAH REV. REQ'T CHANGE	(1,281,085)

Utah Revenue Requirement Impact: (Note: Excludes indirect impact of tax gross-up change on results ≈ ($264))

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Special Contract Revenue Adjustment (rate base portion) is:
= rate base adj. x RMP rate of return x tax gross-up factor
= $6,546 x 7.906% x 1.6151
≈ $836

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Special Contract Revenue Adjustment (income statement portion) is:
= -Operating rev. for return adj. x tax gross-up factor
= ($793,553) x 1.6151
≈ ($1,281,657)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Special Contract Revenue Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Revenue:					
Situs Contracts	442	1,278,811	S	100.000%	1,278,811

Derivation of Special Contract Revenue Adjustment

Line No.	Special Contract 1	Amount	Source
1	Forecasted Present Revenues in Test Period	$24,224,835	WRG Exhibit No. ____ (WRG-3)
2	2013 Contractual Increase @ RMP's As-Filed GRC Increase	2.2%	= Ln. 13 x 10.0% (see WRG Exhibit No. ____ (WRG-1), Ln. 36, Col. 8)
3	Proposed Test Period Annualized Revenues	$24,762,689	= Ln. 1 x (1 + Ln. 2)
4	Revenue Increase @ RMP's As-Filed GRC Increase	$537,854	= Ln. 3 - Ln. 1
	Special Contract 2		
5	Forecasted Present Revenues in Test Period	$26,946,218	WRG Exhibit No. ____ (WRG-3)
6	2013 Contractual Increase @ RMP's As-Filed GRC Increase	2.7%	= Ln. 13 x Sch. 9 per MWh increase from WRG Exhibit No. ____ (WRG-1), Ln. 10
7	Proposed Test Period Annualized Revenues	$27,687,175	= Ln. 5 x (1 + Ln. 6)
8	Revenue Increase @ RMP's As-Filed GRC Increase	$740,957	= Ln. 7 - Ln. 5
9	Total Special Contract Annualized Revenue Increase	$1,278,811	= Ln. 4 + Ln. 8
	Derivation of percent of 2012 affected by 2012 GRC rates		
10	2012 GRC Rate Effective Date	12-Oct-2012	Input
11	Final Day of 2012	31-Dec-2012	Input
12	Days affected by 2012 rate increase	81	= (Ln 11 - Ln. 10) + 1
13	Percentage of 2012 affected by 2012 GRC rates	22.1%	= Ln 12 ÷ 366 (Leap Year)

Rocky Mountain Power

Utah Retail Operations
UAE Klamath Hydroelectric Settlement Amortization Expense Adjustment
Twelve Months Ending May 31,2013

Line No.		Utah Allocated KHSA-related Settlement Cost Amortization
	(A)	(B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	(1,319,765)
22	Taxes Other Than Income	-
23	Income Taxes - Federal	435,212
24	Income Taxes - State	59,138
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(825,415)
29		
30	Operating Rev For Return:	825,415
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	6,668
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	6,668
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	659,882
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	659,882
55		
56	Total Rate Base:	666,551
	UTAH REV. REQ'T CHANGE	(1,248,009)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Hydroelectric Settlement Amortization Expense Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= $666,551 x 7.906% x 1.6151
≈ $85,107

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Hydroelectric Settlement Amortization Expense Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($825,415) x 1.6151
≈ ($1,333,116)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Klamath Hydroelectric Settlement Agreement

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Depreciation Expense:					
Klamath Relicensing & Settlement Process Costs	404IP	(3,058,219)	SG-P	43.155%	(1,319,765)
Adjustment to Depreciation Reserve:					
Klamath Relicensing & Settlement Process Costs	111IP	1,529,109	SG-P	43.155%	659,882

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Klamath Hydroelectric Settlement Agreement
DERIVATION OF AMORTIZATION EXPENSE FOR KLAMATH RELICENSING & PROCESS COSTS (TERMINAL DATE DEC 2022)

Add Back Test Year Klamath Relicensing & Settlement Process Costs

In-Service Date	May 30, 2012
Amount	81,814,435

	EPIS Balance	Amortization Expense	Depreciation Reserve
		9.449%	
Jun-11	-		-
Jul-11	-	-	-
Aug-11	-	-	-
Sep-11	-	-	-
Oct-11	-	-	-
Nov-11	-	-	-
Dec-11	-	-	-
Jan-12	-	-	-
Feb-12	-	-	-
Mar-12	-	-	-
Apr-12	-	-	-
May-12	81,814,435	-	-
Jun-12	81,814,435	644,208	(644,208)
Jul-12	81,814,435	644,208	(1,288,416)
Aug-12	81,814,435	644,208	(1,932,624)
Sep-12	81,814,435	644,208	(2,576,833)
Oct-12	81,814,435	644,208	(3,221,041)
Nov-12	81,814,435	644,208	(3,865,249)
Dec-12	81,814,435	644,208	(4,509,457)
Jan-13	81,814,435	644,208	(5,153,665)
Feb-13	81,814,435	644,208	(5,797,873)
Mar-13	81,814,435	644,208	(6,442,081)
Apr-13	81,814,435	644,208	(7,086,290)
May-13	81,814,435	644,208	(7,730,498)
	81,814,435	7,730,498	(3,865,249)
	13 Mon Avg	Yr. Ending May13	13 Mon Avg
Adjustments:	**81,814,435**	**7,730,498**	**(3,865,249)**

Data Source: Exhibit RMP____(SRM-3), p. 8.11.4.

Rocky Mountain Power

Utah Retail Operations
UAE Klamath Hydroelectric Settlement Rate Base Carrying Cost Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated KHSA-related Settlement Rate Base Carrying Cost (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	-
24	Income Taxes - State	-
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	-
29		
30	Operating Rev For Return:	-
31		
32	Rate Base:	
33	Electric Plant In Service	
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	-
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	
	UTAH REV. REQ'T CHANGE	(1,355,872)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Hydroelectric Settlement Rate Base Carrying Cost Adjustment (return on rate base portion) is:

= Return adjustment x tax gross-up factor
= ($839,505) x 1.6151
≈ ($1,355,872)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Hydroelectric Settlement Rate Base Carrying Cost Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= $0 x 1.6151
≈ $0

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Klamath Relicensing & Settlement Debt Carrying Cost Adjustment

UAE Recommended Rate of Return on Asset	5.41%
RMP Recommended Rate of Return on Asset	7.906%
Difference	-2.50%

	ACCOUNT	TOTAL COMPANY[1]	FACTOR	FACTOR %	UTAH ALLOCATED	UTAH ALLOCATED RETURN ADJUSTMENT
Rate of Return Adjustment						
Adjust ROR on Klamath Relicensing Costs	302	77,949,186	SG-P	43.155%	33,638,722	(839,505)

Note: 1. This represents the net 13 mo. balance of the Klamath Relicensing Costs incorporating UAE's amortization adjustment.
This adjustment was not run through the Jurisdictional Allocation Model to avoid inadvertent impacts on other accounts.

Rocky Mountain Power

Utah Retail Operations
UAE Klamath Surcharge Revenue Situs Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated KHSA-related Surcharge Situs (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	(7,422,605)
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	(7,422,605)
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	2,480,501
24	Income Taxes - State	337,059
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(4,605,045)
29		
30	Operating Rev For Return:	4,605,045
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	(62,119)
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(62,119)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(62,119)
	UTAH REV. REQ'T CHANGE	(7,445,474)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Surcharge Revenue Situs Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($62,119) x 7.906% x 1.6151
≈ ($7,932)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Surcharge Revenue Situs Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($4,605,045) x 1.6151
≈ ($7,437,542)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Klamath Surcharge Revenue Situs Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to O&M Expense:					
Other Expense	557	(7,422,605)	S	100.000%	(7,422,605)

Note: The California and Oregon Klamath Surcharge revenue is treated as a negative expense for Utah in this adjustment.

Data Source: Exhibit RMP ____ (SRM-3), p. 11.8.

Rocky Mountain Power
Utah Retail Operations
UAE Klamath Hydroelectric Depreciation Expense Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated KHSA-related Depreciation Expense (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	(2,391,629)
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	788,694
24	Income Taxes - State	107,170
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(1,495,765)
29		
30	Operating Rev For Return:	1,495,765
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	12,085
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	12,085
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	1,193,564
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	1,193,564
55		
56	Total Rate Base:	1,205,649
	UTAH REV. REQ'T CHANGE	(2,261,847)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Hydroelectric Depreciation Expense Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= $1,205,649 x 7.906% x 1.6151
≈ $153,941

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Klamath Hydroelectric Depreciation Expenses Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($1,495,765) x 1.6151
≈ ($2.415,788)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Klamath Hydroelectric Settlement Agreement

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Depreciation Expense:					
Existing Klamath: Test Period	403HP	(5,541,993)	SG-P	43.155%	(2,391,629)
Adjustment to Depreciation Reserve:					
Existing Klamath: Test Period	108HP	2,765,782	SG-P	43.155%	1,193,564

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Klamath Hydroelectric Settlement Agreement
DERIVATION OF DEPRECIATION EXPENSE FOR EXISTING KLAMATH

Base Year Ended June 2011

	Per Books: June11		Accelerated Amount: June11*		Adjusted Actuals: June11			
Existing Klamath:	**YE**	**B/E Avg**	**YE**	**B/E Avg**	**YE**		**B/E Avg**	
Gross EPIS	84,295,830	83,228,609			84,295,830	(A)	83,228,609	(D)
Depreciation Reserve	(31,331,379)	(29,671,521)	(2,154,440)	**(1,077,220)**	(29,176,939)	(B)	(28,594,301)	(E)
Depreciation Expense	3,705,240		**2,154,440**	**Ref. 8.11**	1,550,801	(C)		
			Ref. 8.11					
			Ref. 8.11.3					

*Effective January 1, 2011, depreciation was accelerated on the Company's books prior to the settlement in Docket No. 10-035-124 which postponed this issue to a future proceeding. The accelerated amount for January 2011 through June 2011 is removed as part of this adjustment.

Test Year Ending May 2013

	Capital Additions	EPIS Balance		Depreciation Expense**			Depreciation Reserve	
				1.884%	8.319%			
Jun-11		84,295,830	(A)				(29,176,939)	(B)
Jul-11	-	84,295,830		132,367	-		(29,309,305)	
Aug-11	-	84,295,830		132,367	-		(29,441,672)	
Sep-11	-	84,295,830		132,367	-		(29,574,039)	
Oct-11	-	84,295,830		132,367	-		(29,706,405)	
Nov-11	489,106	84,784,936		132,751	-		(29,839,156)	
Dec-11	612,039	85,396,975		133,615	-		(29,972,771)	
Jan-12	-	85,396,975		134,096	-		(30,106,867)	
Feb-12	1,000	85,397,975		134,097	-		(30,240,964)	
Mar-12	2,000	85,399,975		134,099	-		(30,375,063)	
Apr-12	20,000	85,419,975		134,116	-		(30,509,179)	
May-12	279,621	85,699,596		134,351	-		(30,643,531)	
Jun-12	-	85,699,596		134,571			(30,778,102)	
Jul-12	140,622	85,840,218		134,681			(30,912,783)	
Aug-12	760	85,840,978		134,792			(31,047,575)	
Sep-12	-	85,840,978		134,793			(31,182,368)	
Oct-12	-	85,840,978		134,793			(31,317,161)	
Nov-12	-	85,840,978		134,793			(31,451,954)	
Dec-12	650,297	86,491,275		135,304			(31,587,258)	
Jan-13	-	86,491,275		135,814			(31,723,072)	
Feb-13	-	86,491,275		135,814			(31,858,886)	
Mar-13	-	86,491,275		135,814			(31,994,700)	
Apr-13	-	86,491,275		135,814			(32,130,515)	
May-13	-	86,491,275		135,814			(32,266,329)	
	2,195,444	86,119,305	(F)	1,622,798		(G)	(31,453,403)	(H)
		13 Mon Avg			Yr. Ending May13		13 Mon Avg	
	Adjustments:	**2,890,697**	(I = F - D)		**71,998**	(J = G - C)	**(2,859,101)**	(K = H - E)

Data Source: Exhibit RMP____(SRM-3), p. 8.11.2

Rocky Mountain Power

Utah Retail Operations
UAE Property Tax Expense Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Property Tax (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	(3,571,561)
23	Income Taxes - Federal	1,193,551
24	Income Taxes - State	162,184
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(2,215,826)
29		
30	Operating Rev For Return:	2,215,826
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	(29,890)
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(29,890)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(29,890)
	UTAH REV. REQ'T CHANGE	(3,582,565)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Property Tax Expense Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($29,890) x 7.906% x 1.6151
≈ ($3,816)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Property Tax Expense Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($2,215,826) x 1.6151
≈ ($3,578,748)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Property Tax Expense Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Expense:					
Taxes Other Than Income	408	(8,334,330)	GPS	42.8536%	(3,571,561)

Data Sources: Exhibit RMP___(SRM-3), page 7.2.1 and WY Docket 20000-405-ER-11: RMP Response to WIEC 29.7.

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Property Tax Adjustment Summary

FERC Account	**Factor**	**Total**
408.15	GPS	100,512,228
Total Accrued Property Tax - 12 Months End. June 2011 (Erroneous RMP Filed)		100,512,228
408.15	GPS	108,846,558
Total Accrued Property Tax - 12 Months End. June 2011 (Corrected)		108,846,558
Property Tax Exp. for the Twelve Months Ending Dec 2012		**121,068,000**
Property Tax Exp. for the Twelve Months Ending Dec 2013		**124,768,000**
Estimated Property Tax Exp. For the Twelve Months Ended May 2013		122,609,667
Less Accrued Property Tax - 12 Months Ended June 30, 2011		108,846,558
Incremental Adjustment to Property Taxes		**13,763,109**

Data Sources: Exhibit RMP___(SRM-3), page 7.2.1; WY Docket 20000-405-ER-11: RMP Response to WIEC 29.7.

Rocky Mountain Power

Utah Retail Operations
UAE Wage and Benefit Expense Adjustment - Wage Increase
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Wage & Benefit - Wage Increase (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	(12,677)
10	Nuclear Production	-
11	Hydro Production	(1,862)
12	Other Power Supply	(4,481)
13	Transmission	(2,665)
14	Distribution	(11,505)
15	Customer Accounting	(5,833)
16	Customer Service & Info	(896)
17	Sales	-
18	Administrative & General	(10,784)
19	Total O&M Expenses	(50,702)
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	16,944
24	Income Taxes - State	2,302
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(31,456)
29		
30	Operating Rev For Return:	31,456
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	(424)
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(424)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(424)
	UTAH REV. REQ'T CHANGE	(50,859)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wage and Benefit Expense Adjustment - Wage Increase (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($424) x 7.906% x 1.6151
≈ ($54)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wage and Benefit Expense Adjustment - Wage Increase (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($31,456) x 1.6151
≈ ($50,804)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Wage Increase Expense Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Expense:					
Adjustment to Wage Increase Expense:	500-935	(118,394)	Multiple	Multiple	(50,702)
Regular Time/Overtime/Premium Pay Expense Adj		(136,749)			(58,563)
Unused Leave Accrual Expense Adj		(582)			(249)
JO Cutbacks Expense Adj		343			147
Annual Incentive Compensation Expense Adj		(19,160)			(8,205)
Payroll Tax Expense Adj		(11,202)			(4,797)
Subtotal:		(167,350)			(71,668)
Capitalized Labor:		(48,956)			(20,966)
Total Adjustment to Wage Increase Expense:		(118,394)			(50,702)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Wage Increase Expense Adjustment

UAE Composite Labor Increases

Regular Time/Overtime/Premium Pay June 2011 - ACTUAL		483,287,052
Regular Time/Overtime/Premium Pay May 2013 - UAE PRO FORMA		500,621,701
	% Increase	3.59%

RMP Composite Labor Increases

Regular Time/Overtime/Premium Pay June 2011 - ACTUAL		483,287,052
Regular Time/Overtime/Premium Pay May 2013 - UAE PRO FORMA		500,758,450
	% Increase	3.62%

Difference: **(136,749)**

UAE Miscellaneous Bare Labor Escalation

Description	Account	June 2011 Actual	Pro Forma Increase	May 2013 Pro Forma	Pro Forma Adjustment
Unused Sick Leave Accrual	5005XX	2,055,421	3.59%	2,129,146	**73,724**
Joint Owner Cutbacks	50109X	(1,210,862)	3.59%	(1,254,293)	**(43,431)**
		844,560		874,853	30,293

RMP Miscellaneous Bare Labor Escalation

Description	Account	June 2011 Actual	Pro Forma Increase	May 2013 Pro Forma	Pro Forma Adjustment
Unused Sick Leave Accrual	5005XX	2,055,421	3.62%	2,129,727	**74,306**
Joint Owner Cutbacks	50109X	(1,210,862)	3.62%	(1,254,636)	**(43,774)**
		844,560		875,092	30,532

Difference: **(239)**

UAE Annual Incentive Plan Escalation

Description	Account	June 2011 Actual	May 2013 Pro Forma	Pro Forma Adjustment
Annual Incentive Plan Compensation	500410	29,448,840	29,031,563	**(417,277)**

RMP Annual Incentive Plan Escalation

Description	Account	June 2011 Actual	May 2013 Pro Forma	Pro Forma Adjustment
Annual Incentive Plan Compensation	500410	29,448,840	29,050,723	**(398,117)**

Difference: **(19,160)**

UAE Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2009	180,514,059	8,125,239	11,472,744	200,112,042	29,876,294	14.93%
Cy 2010	177,805,237	8,161,210	11,363,613	197,330,060	26,606,117	13.48%
Cy 2011	181,985,233	8,213,064	12,660,309	202,858,606	27,627,365	13.62%
3-year Total	540,304,529	24,499,512	35,496,666	600,300,708	84,109,776	14.01%
Test Year	**186,667,182**	**8,075,391**	**12,458,878**	207,201,451	**29,031,563**	14.01%

RMP Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2009	180,514,059	8,125,239	11,472,744	200,112,042	29,876,294	14.93%
Cy 2010	177,805,237	8,161,210	11,363,613	197,330,060	26,606,117	13.48%
Cy 2011	181,985,233	8,213,064	12,660,309	202,858,606	27,627,365	13.62%
3-year Total	540,304,529	24,499,512	35,496,666	600,300,708	84,109,776	14.01%
Test Year	**186,795,375**	**8,075,391**	**12,467,434**	207,338,200	**29,050,723**	14.01%

Difference: **(19,160)**

* Data Sources: RMP Exhibit (SRM-3), p. 4.2.6 and RMP Responses to UAE Data Request 3.4 & OCS Data Request 8.18.

Rocky Mountain Power
Utah Retail Operations
UAE Wage and Benefit Expense Adjustment - PBOP Update
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Wage & Benefit - PBOP Update (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	(47,136)
10	Nuclear Production	-
11	Hydro Production	(6,922)
12	Other Power Supply	(16,661)
13	Transmission	(9,910)
14	Distribution	(42,780)
15	Customer Accounting	(21,687)
16	Customer Service & Info	(3,330)
17	Sales	-
18	Administrative & General	(40,097)
19	Total O&M Expenses	(188,523)
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	63,001
24	Income Taxes - State	8,561
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(116,961)
29		
30	Operating Rev For Return:	116,961
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	(1,578)
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(1,578)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(1,578)
	UTAH REV. REQ'T CHANGE	(189,104)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wage and Benefit Expense Adjustment - PBOP Update (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($1,578) x 7.906% x 1.6151
≈ ($201)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wage and Benefit Expense Adjustment - PBOP Update (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($116,961) x 1.6151
≈ ($188,903)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Postretirement Benefits-FAS 106 (PBOP) Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Expense:					
Post Retirement Benefits - FAS 106 Adjustment:	500-935	(440,217)	Multiple	Multiple	(188,523)
Post Retirement Benefits - FAS 106 Expense Adj:		(622,249)			(266,479)
Capitalized Labor:		(182,032)			(77,955)
Total Post Retirement Benefits - FAS 106 Adjustment:		(440,217)			(188,523)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Postretirement Benefits-FAS 106 (PBOP) Adjustment

RMP Proposed Benefit Expense

		A	B	C	D	D - A
Account	**Description**	**Actual June 2011 Net of Joint Venture**	**Actual June 2011 GROSS**	**May 2013 Projected GROSS**	**May 2013 Projected Net of Joint Venture**	**Pro Forma Adjustment**
50110X	Pensions - FAS 87	30,032,084	30,770,663	39,816,667	38,860,959	**8,828,875**
501115	SERP Plan	3,479,776	3,479,776	3,500,000	3,500,000	**20,224**
50115X	Post Retirement Benefits - FAS 106	15,216,196	15,691,024	2,208,333	2,141,507	**(13,074,690)**
501160	Post Employment Benefits - FAS 112	6,320,724	6,511,478	6,746,876	6,549,226	**228,502**
	Subtotal	55,048,781	56,452,941	52,271,876	51,051,692	**(3,997,088)**
501102	Pension Administration	111,401	111,411	111,411	111,401	**-**
50112X	Medical	58,079,222	59,890,015	60,964,904	59,121,611	**1,042,390**
501175	Dental	1,902,305	1,975,563	2,371,110	2,283,185	**380,879**
501200	Vision	253,027	263,100	264,135	254,022	**995**
50122X	Life	948,113	976,890	1,012,205	982,388	**34,275**
501250	401(k)	19,146,764	19,748,798	20,821,648	20,186,908	**1,040,144**
501251	401(k) Administration	190,122	195,872	195,872	190,122	**-**
501252	401(k) Fixed	16,775,895	17,571,755	18,206,994	17,382,364	**606,468**
501275	Accidental Death & Disability	49,500	49,884	51,687	51,290	**1,789**
501300	Long-Term Disability	3,162,992	3,258,440	3,376,236	3,277,337	**114,346**
5016XX	Worker's Compensation	1,614,303	1,660,816	1,720,856	1,672,662	**58,359**
502900	Other Salary Overhead	1,997,686	1,999,080	1,999,080	1,997,686	**-**
	Subtotal	104,231,331	107,701,623	111,096,139	107,510,977	**3,279,647**
	Grand Total	159,280,111	164,154,564	163,368,015	**158,562,669**	**(717,442)**

UAE Recommended Benefit Expense

		A	B	C	D	D - A
Account	**Description**	**Actual June 2011 Net of Joint Venture**	**Actual June 2011 GROSS**	**May 2013 Projected GROSS**	**May 2013 Projected Net of Joint Venture**	**Pro Forma Adjustment**
50110X	Pensions - FAS 87	30,032,084	30,770,663	39,816,667	38,860,959	**8,828,875**
501115	SERP Plan	3,479,776	3,479,776	3,500,000	3,500,000	**20,224**
50115X	**Post Retirement Benefits - FAS 106**	**15,216,196**	**15,691,024**	**1,566,667**	**1,519,258**	**(13,696,938)**
501160	Post Employment Benefits - FAS 112	6,320,724	6,511,478	6,746,876	6,549,226	**228,502**
	Subtotal	55,048,781	56,452,941	51,630,209	50,429,443	**(4,619,337)**
501102	Pension Administration	111,401	111,411	111,411	111,401	**-**
50112X	Medical	58,079,222	59,890,015	60,964,904	59,121,611	**1,042,390**
501175	Dental	1,902,305	1,975,563	2,371,110	2,283,185	**380,879**
501200	Vision	253,027	263,100	264,135	254,022	**995**
50122X	Life	948,113	976,890	1,012,205	982,388	**34,275**
501250	401(k)	19,146,764	19,748,798	20,821,648	20,186,908	**1,040,144**
501251	401(k) Administration	190,122	195,872	195,872	190,122	**-**
501252	401(k) Fixed	16,775,895	17,571,755	18,206,994	17,382,364	**606,468**
501275	Accidental Death & Disability	49,500	49,884	51,687	51,290	**1,789**
501300	Long-Term Disability	3,162,992	3,258,440	3,376,236	3,277,337	**114,346**
5016XX	Worker's Compensation	1,614,303	1,660,816	1,720,856	1,672,662	**58,359**
502900	Other Salary Overhead	1,997,686	1,999,080	1,999,080	1,997,686	**-**
	Subtotal	104,231,331	107,701,623	111,096,139	107,510,977	**3,279,647**
	Grand Total	159,280,111	164,154,564	162,726,348	**157,940,420**	**(1,339,691)**

* Data Sources: RMP Exhibit SRM-3, p. 4.2.7 & RMP Response to Data Request OCA 6.12

Rocky Mountain Power

Utah Retail Operations
UAE O&M Expense Escalation Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated O&M Expense Escalation (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	(4,005,086)
10	Nuclear Production	-
11	Hydro Production	(701,979)
12	Other Power Supply	(1,586,216)
13	Transmission	(875,829)
14	Distribution	(2,612,018)
15	Customer Accounting	(498,371)
16	Customer Service & Info	(129,467)
17	Sales	-
18	Administrative & General	825,151
19	Total O&M Expenses	(9,583,815)
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	3,202,739
24	Income Taxes - State	435,199
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(5,945,878)
29		
30	Operating Rev For Return:	5,945,878
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	(80,206)
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(80,206)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(80,206)
	UTAH REV. REQ'T CHANGE	(9,613,343)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's O&M Expense Escalation Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($80,206) x 7.906% x 1.6151
≈ ($10,241)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's O&M Expense Escalation Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($5,945,878) x 1.6151
≈ ($9,603,102)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
UAE Non-Power Cost O&M Escalation Adjustment

		ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustments to Expense:						
	O&M Escalation Adjustment:	500-935	(24,308,454)	Multiple	Multiple	(9,583,815)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
UAE Non-Power Cost O&M Escalation Adjustment Detail

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustments to Expense:					
Global O&M Escalation Adjustment [1]	500-935	(25,016,305)	Multiple	Multiple	(10,188,783)
Add O&M Escalation Expense [2]					
Electric Lake Settlement Amortization O&M Escalation:	557	53,712	SG	43.1547%	23,179
Little Mountain Non-Labor O&M Escalation:	548	18,550	SG	43.1547%	8,005
Snake Creek O&M Expense:	539	6,087	SG-U	43.1547%	2,627
Condit O&M Expense:	539	25,966	SG-P	43.1547%	11,205
Total Miscellaneous Asset Sales and Removals O&M Escalation:	539	32,053	Multiple	Multiple	13,833
Operation Supervision & Engineering Expense:	535	476	SG-P	43.1547%	205
Hydraulic Expense:	537	687	SG-P	43.1547%	297
Misc. Hydro Expense:	539	867	SG-P	43.1547%	374
Rents (Hydro Generation) Expense:	540	10	SG-P	43.1547%	4
Maintenance of Misc. Hydro Plant Expense:	545	298	SG-P	43.1547%	129
Total Powerdale Hydro Removal O&M Escalation:	535-545	2,338	SG-P	43.1547%	1,009
Glenrock Mine Amortization Expense:	930	1,561	UT	100.00%	1,561
Cholla Transaction Costs:	557	74,527	SGCT	43.3005%	32,271
Pension Curtailment Gain Amortization Expense:	920	321,713	UT	100.00%	321,713
Pension Measurement Date Change:	920	30,371	UT	100.00%	30,371
Weatherization Regulatory Assets:	908	7,611	UT	100.00%	7,611
Total Regulatory Asset Amortization Expense Escalation:	557-930	435,784	Multiple	Multiple	393,527
Utah Automated Reading Program Expense Escalation:	902	1,424	UT	100.00%	1,424
Uncollectible Accounts Expense Escalation:	904	163,991	UT	100.00%	163,991
Total O&M Expense Escalation Adjustment:		**(24,308,454)**			**(9,583,815)**

[1] This adjustment reverses RMP's O&M Escalation Adjustment shown on page 4.12 of Exhibit SRM-3.

[2] This adjustment reflects the exceptions to UAE's removal of inflation and reverses the escalation adjustments in UAE's Global O&M Escalation Adjustment.

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
UAE Non-Power Cost O&M Escalation Adjustment Detail

Steam Power Generation	RMP As Filed	UAE Recommended	UAE Total Company Adjustment	Allocation Factor	UAE Utah Adjustment
SG	155,746,930	149,371,511	(6,375,419)	43.15%	(2,751,292)
SE	19,270,723	17,970,953	(1,299,771)	42.95%	(558,295)
SSGCH	26,258,166	24,878,719	(1,379,447)	43.15%	(595,296)
SSECH	3,458,724	3,225,441	(233,284)	42.95%	(100,203)
NPCID	(103,365)	(103,365)	0		
NPCSE	617,817,176	617,817,176	0		
NPCWYP	(305,917)	(305,917)	0		
NPCSSECH	49,297,564	49,297,564	0		
Total Steam Power Generation	871,440,002	862,152,081	(9,287,921)		(4,005,086)
Hydro Power Generation					
SG-P	24,969,010	23,376,089	(1,592,922)	43.15%	(687,420)
SG-U	1,361,396	1,293,269	(68,127)	43.15%	(29,400)
Total Hydro Power Generation	26,330,407	24,669,358	(1,661,049)		(716,820)
Other Production Expense					
SG	17,621,901	16,667,174	(954,727)	43.15%	(412,010)
SSGCT	1,233,890	1,167,541	(66,350)	43.15%	(28,633)
SGCT	0	0	0	43.30%	0
SSECT	0	0	0	42.97%	0
NPCSE	365,731,151	365,731,151	0		
NPCSSECT	16,065,664	16,065,664	0		
SG-W	27,873,024	26,237,180	(1,635,844)	43.15%	(705,943)
ID	0	0	0		
OR	0	0	0		
WA	0	0	0		
Total Other Production Expense	428,525,630	425,868,709	(2,656,921)		(1,146,586)
Power Supply Expense					
SG	17,522,040	16,431,047	(1,090,993)	43.15%	(470,815)
CA	0	0	0		0
ID	9,593,273	8,995,957	(597,316)		0
OR	(57,386)	(53,813)	3,573		0
SE	0	0	0	42.95%	0
SGCT	1,196,952	1,122,425	(74,527)	43.30%	(32,271)
SSGCT	0	0	0	43.15%	0
UT	0	0	0	100.00%	0
WYP	0	0	0	0.00%	0
WA	(103,447)	(97,006)	6,441		
Total Power Supply Expense	28,151,432	26,398,610	(1,752,822)		(503,085)
Transmission Expense					
SG	39,990,605	37,961,093	(2,029,512)	43.15%	(875,829)
NPCSE	6,292,490	6,292,490	0		
NPCSG	131,608,086	131,608,086	0		
Total Transmission Expense	177,891,180	175,861,669	(2,029,512)		(875,829)
Distribution Expense					
SNPD	3,487,423	3,322,475	(164,948)	48.09%	(79,327)
WYP	8,588,900	8,087,610	(501,290)	0.00%	0
WYU	1,607,110	1,512,104	(95,006)	0.00%	0
CA	5,398,812	5,080,092	(318,720)		
ID	4,475,105	4,210,535	(264,570)		
OR	30,333,922	28,566,739	(1,767,183)		
UT	43,015,465	40,482,774	(2,532,691)	100.00%	(2,532,691)
WA	5,535,077	5,211,294	(323,783)		
Total Distribution Expense	102,441,814	96,473,624	(5,968,191)		(2,612,018)
Customer Accounting Exp					
CN	17,704,362	16,883,074	(821,288)	49.89%	(409,763)
WYP	1,251,678	1,193,614	(58,064)	0.00%	0
WYU	87,962	83,882	(4,080)	0.00%	0
CA	719,973	686,574	(33,399)		
ID	902,477	860,612	(41,865)		
OR	8,566,301	8,168,918	(397,382)		
UT	5,475,915	5,221,893	(254,022)	100.00%	(254,022)
WA	2,215,231	2,112,468	(102,762)		
Total Customer Accounting Exp	36,923,900	35,211,036	(1,712,864)		(663,786)
Customer Service Expense					
CN	4,227,665	4,032,431	(195,234)	49.89%	(97,408)
OTHER	5,192,538	4,952,746	(239,792)	0.00%	0
WYP	310,078	295,758	(14,319)		
UT	859,041	819,370	(39,671)	100.00%	(39,671)
ID	469,354	447,679	(21,675)		
OR	298,800	285,001	(13,799)		
WA	88,718	84,621	(4,097)		
WYU	0	0	0	0.00%	0
CA	264,908	252,675	(12,233)		
Total Customer Service Expense	11,711,103	11,170,283	(540,820)		(137,078)
Administrative & General Expense					
CN	0	0	0	49.89%	0
SG	1,737,642	1,657,049	(80,593)	43.15%	(34,780)
SO	32,906,360	33,920,713	1,014,353	42.85%	434,687
WYP	937,480	905,492	(31,989)	0.00%	0
WYU	32,366	31,255	(1,111)	0.00%	0
OR	7,482,032	7,200,215	(281,817)		0
UT	(290,562)	(218,963)	71,599	100.00%	71,599
WA	191,821	188,739	(3,082)		0
CA	561,621	536,923	(24,698)		0
ID	1,500,989	1,432,121	(68,868)		0
Total Administrative & General Expense	45,059,750	45,653,545	593,794		471,506
Purchased Power Expense:	423,000,929	423,000,929	0		0
TOTAL:	**2,151,476,148**	**2,126,459,843**	**(25,016,305)**		**(10,188,783)**

Rocky Mountain Power

Utah Retail Operations
UAE Wind Turbine O&M Expense Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Wind Turbine O&M Expense (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	(597,872)
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	(597,872)
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	199,798
24	Income Taxes - State	27,149
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(370,925)
29		
30	Operating Rev For Return:	370,925
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	(5,004)
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(5,004)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(5,004)
	UTAH REV. REQ'T CHANGE	(599,714)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wind Turbine O&M Expense Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($5,004) x 7.906% x 1.6151
≈ ($639)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Wind Turbine O&M Expense Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($370,925) x 1.6151
≈ ($599,075)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Wind Turbine O&M Expense Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Wind Generation:					
Oil Changes	549	(1,385,417)	SG-W	43.155%	(597,872)

Data Sources: Exhibit RMP___(SRM-3), p. 4.9.2 and WY Docket No. 20000-405-ER-11, Exhibit RMP__(SRM-2R), page 12.10.

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Wind Turbine O&M Expense Adjustment

	ACCOUNT	FACTOR	FACTOR %	RMP TOTAL COMPANY[1]	RMP UTAH ALLOCATED	UAE TOTAL COMPANY[2]	UAE UTAH ALLOCATED	DIFFERENCE UAE-RMP TOTAL COMPANY	DIFFERENCE UAE-RMP UTAH ALLOCATED
Wind Generation									
Oil Changes	549	SG-W	43.155%	3,044,000	1,313,628	$ 1,658,583	$ 715,756	$ (1,385,417)	$ (597,872)

Data Sources: 1. Exhibit RMP__(SRM-3), page 4.9.2; 2. WY Docket No. 20000-405-ER-11, Exhibit RMP__(SRM-2R), page 12.10.

Rocky Mountain Power
Utah Retail Operations
UAE Legal Expense Disallowance Adjustment
Twelve Months Ending May 31,2013

Line No.		Utah Allocated Legal Expense Disallowance
	(A)	(B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	[redacted]
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	[redacted]
19	Total O&M Expenses	[redacted]
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	[redacted]
24	Income Taxes - State	[redacted]
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	[redacted]
29		
30	Operating Rev For Return:	1,200,145
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	[redacted]
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	[redacted]
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(16,189)
	UTAH REV. REQ'T CHANGE	(1,940,404)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Legal Expense Disallowance Adjustment (rate base portion) is:
= rate base adj. x RMP rate of return x tax gross-up factor
= ($16,189) x 7.906% x 1.6151
≈ ($2,067)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Legal Expense Disallowance Adjustment (income statement portion) is:
= -Operating rev. for return adj. x tax gross-up factor
= ($1,200,145) x 1.6151
≈ ($1,938,337)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Legal Expense Disallowance Adjustment (CONFIDENTIAL)

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to O&M Expense:					
Other Production Expense (USA Power v. Williams)	557	[redacted]	SG	43.155%	[redacted]
Other Production Expense (Deseret Hunter 2)	557		SG	43.155%	
Other Production Expense (APEX Acquisition)	557		SG	43.155%	
Other Production Expense (Deseret Turbine)	557		SG	43.155%	
Other Production Expense - Total					
Outside Services Expense (Wah Chang v. PacifiCorp)	923	[redacted]	SO	42.854%	[redacted]
Outside Services Expense - Total					

Data Source: RMP CONFIDENTIAL Response to ICNU Data Request 2.34 (Oregon Docket UE-246)
[Response Used with RMP Permission]

Rocky Mountain Power

Utah Retail Operations
UAE Plant Held for Future Use Rate Base Adjustment
Twelve Months Ending May 31,2013

Line No.		Utah Allocated Plant Held for Future Use
	(A)	(B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	37,255
24	Income Taxes - State	5,062
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	42,317
29		
30	Operating Rev For Return:	(42,317)
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	(4,330,588)
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	571
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(4,330,017)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(4,330,017)
	UTAH REV. REQ'T CHANGE	(484,524)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Plant Held for Future Use Rate Base Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($4,330,017) x 7.906% x 1.6151
≈ ($552,870)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Plant Held for Future Use Rate Base Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= $42,317 x 1.6151
≈ $68,346

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Plant Held for Future Use Adjustment Detail

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustments to PHFU (Prod):					
Remove Wild Horse Wind Farm	105SNPP	(6,763,094)	SG	43.155%	(2,918,592)
Remove Twelve Mile Wind Farm	105SNPP	(2,160,207)	SG	43.155%	(932,230)
Total Production PHFU Adjustment:		(8,923,302)			(3,850,822)
Adjustments to PHFU (Trans):					
Remove Aeolus Substation	105SNPT	(507,026)	SG	43.155%	(218,806)
Remove Anticline Substation	105SNPT	(477,332)	SG	43.155%	(205,991)
Remove Populus Substation - Bastion Property	105SNPT	(127,377)	SG	43.155%	(54,969)
Total Transmission PHFU Adjustment:		(1,111,734)			(479,765)

Data Source: RMP Response to UAE 4.7 Attachment and WY Docket 20000-405-ER-11

Rocky Mountain Power

Utah Retail Operations
UAE Contingency Cost Rate Base Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Contingency Cost Rate Base Adjustment (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	(94,871)
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	484,227
24	Income Taxes - State	65,798
25	Income Taxes - Def Net	(482,711)
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	(27,556)
29		
30	Operating Rev For Return:	27,556
31		
32	Rate Base:	
33	Electric Plant In Service	(4,096,458)
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	7,419
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(4,089,039)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	60,084
48	Accum Prov For Amort	-
49	Accum Def Income Tax	825,212
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	885,296
55		
56	Total Rate Base:	(3,203,743)
	UTAH REV. REQ'T CHANGE	(453,569)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Contingency Cost Rate Base Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($3,203,743) x 7.906% x 1.6151
≈ ($409,064)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Contingency Cost Rate Base Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= ($27,556) x 1.6151
≈ ($44,506)

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Contingency Cost Rate Base Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to Rate Base:					
Steam Plant Additions	312	(7,590,989)	SG	43.155%	(3,275,867)
Hydro Plant Additions	332	(1,607,742)	SG	43.155%	(693,816)
Transmission Plant Additions	355	(293,769)	SG	43.155%	(126,775)
		(9,492,500)			(4,096,458)
Accumulated Depreciation Reserve	108SP	128,209	SG	43.155%	55,328
Accumulated Depreciation Reserve	108HP	9,815	SG	43.155%	4,236
Accumulated Depreciation Reserve	108TP	1,206	SG	43.155%	520
		139,230			60,084
Accumulated Deferred Income Tax	282	1,912,218	SG	43.155%	825,212
		1,912,218			825,212
Adjustment to Expenses:					
Depreciation Expense	403SP	(180,727)	SG	43.155%	(77,992)
Depreciation Expense	403HP	(33,994)	SG	43.155%	(14,670)
Depreciation Expense	403TP	(5,118)	SG	43.155%	(2,209)
		(219,839)			(94,871)
Adjustment to Taxes:					
Deferred Income Tax Expense	41010	(1,118,559)	SG	43.155%	(482,711)
		(1,118,559)			(482,711)
Schedule M Deductions - Temporary	SCHMDT	(2,947,377)	SG	43.155%	(1,271,931)
		(2,947,377)			(1,271,931)

Derivation of UAE Adjustment To Remove a Portion of the Contingency Costs included in Pro Forma Capital Additions

Rate Base and Depreciation Expense Impact

Description		FERC Accts	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Plant in Service															
Naughton U2 Flue Gas Desulfurization Sys		312	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,389,118	$2,389,118
Depreciation Expense															
Naughton U2 Flue Gas Desulfurization Sys	2.370%	403SP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,360	$4,719
Accumulated Depreciation															
Naughton U2 Flue Gas Desulfurization Sys		108SP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,360	$7,079

Description		FERC Accts	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Plant in Service															
Naughton U2 Flue Gas Desulfurization Sys		312	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118
Naughton U1 Flue Gas Desulfurization Sys		312	$0	$0	$0	$0	$0	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529
DJ U4 SO2 & PM Emission Cntrl Upgrades		312	$0	$0	$0	$0	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033
Hunter U1 SO2 Upgrades		312	$0	$0	$0	$0	$0	$0	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250
Hunter 303 Turbine Upgrade HP/IP/LP		312	$0	$0	$0	$0	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500
INU 4.1.1/4.1.2 Soda Springs Fish Passag		332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$525,950	$525,950	$525,950	$525,950
ILR 4.4 Swift Fish Collector		332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,608,000
ILR 4.3 Merwin Upstream Collect & Trans		332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$140,700
Ashton Dam Seepage Control		332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$542,700	$542,700
IRO Prospect Instream Flow / Automation		332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$268,000	$268,000
Clover Substation		355	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$536,000
Depreciation Expense															
Naughton U2 Flue Gas Desulfurization Sys	2.370%	403SP	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719
Naughton U1 Flue Gas Desulfurization Sys	2.370%	403SP	$0	$0	$0	$0	$0	$2,043	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086
DJ U4 SO2 & PM Emission Cntrl Upgrades	2.370%	403SP	$0	$0	$0	$0	$1,629	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257
Hunter U1 SO2 Upgrades	2.370%	403SP	$0	$0	$0	$0	$0	$0	$1,241	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481
Hunter 303 Turbine Upgrade HP/IP/LP	2.370%	403SP	$0	$0	$0	$0	$298	$596	$596	$596	$596	$596	$596	$596	$596
INU 4.1.1/4.1.2 Soda Springs Fish Passag	1.964%	403HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$430	$861	$861	$861
ILR 4.4 Swift Fish Collector	1.964%	403HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,316
ILR 4.3 Merwin Upstream Collect & Trans	1.964%	403HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$115
Ashton Dam Seepage Control	2.749%	403HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$622	$1,243
IRO Prospect Instream Flow / Automation	1.964%	403HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$219	$439
Clover Substation	1.890%	403TP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$422
Accumulated Depreciation															
Naughton U2 Flue Gas Desulfurization Sys		108SP	$7,079	$11,798	$16,517	$21,236	$25,955	$30,674	$35,393	$40,112	$44,831	$49,551	$54,270	$58,989	$63,708
Naughton U1 Flue Gas Desulfurization Sys		108SP	$0	$0	$0	$0	$0	$2,043	$6,129	$10,215	$14,301	$18,386	$22,472	$26,558	$30,644
DJ U4 SO2 & PM Emission Cntrl Upgrades		108SP	$0	$0	$0	$0	$1,629	$4,886	$8,143	$11,400	$14,658	$17,915	$21,172	$24,429	$27,687
Hunter U1 SO2 Upgrades		108SP	$0	$0	$0	$0	$0	$0	$1,241	$3,722	$6,204	$8,685	$11,166	$13,648	$16,129
Hunter 303 Turbine Upgrade HP/IP/LP		108SP	$0	$0	$0	$0	$298	$893	$1,489	$2,084	$2,680	$3,275	$3,871	$4,467	$5,062
INU 4.1.1/4.1.2 Soda Springs Fish Passag		108HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$430	$1,291	$2,152	$3,013
ILR 4.4 Swift Fish Collector		108HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,316
ILR 4.3 Merwin Upstream Collect & Trans		108HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$115
Ashton Dam Seepage Control		108HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$622	$1,865
IRO Prospect Instream Flow / Automation		108HP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$219	$658
Clover Substation		108TP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$422

Derivation of UAE Adjustment To Remove a Portion of the Contingency Costs included in Pro Forma Capital Additions

Rate Base and Depreciation Expense Impact

Description		FERC Accts	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Future Test Period Amounts
Plant in Service																
Naughton U2 Flue Gas Desulfurization Sys		312	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118	$2,389,118
Naughton U1 Flue Gas Desulfurization Sys		312	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529	$2,068,529
DJ U4 SO2 & PM Emission Cntrl Upgrades		312	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033	$1,649,033
Hunter U1 SO2 Upgrades		312	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,256,250	$1,159,615
JB U2 Turbine Upgrade HP/IP/LP		312	$0	$0	$0	$0	$0	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$23,192
Hunter 303 Turbine Upgrade HP/IP/LP		312	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500	$301,500
INU 4.1.1/4.1.2 Soda Springs Fish Passag		332	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$525,950	$364,119
ILR 4.4 Swift Fish Collector		332	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$1,608,000	$742,154
ILR 4.3 Merwin Upstream Collect & Trans		332	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$140,700	$64,938
Ashton Dam Seepage Control		332	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$542,700	$292,223
IRO Prospect Instream Flow / Automation		332	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$268,000	$144,308
Clover Substation		355	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$536,000	$247,385
Lake Side 2 Interconnect		355	$0	$0	$0	$0	$0	$603,000	$603,000	$603,000	$603,000	$603,000	$603,000	$603,000	$603,000	$46,385
Depreciation Expense																
Naughton U2 Flue Gas Desulfurization Sys	2.370%	403SP	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$4,719	$56,629
Naughton U1 Flue Gas Desulfurization Sys	2.370%	403SP	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$4,086	$49,030
DJ U4 SO2 & PM Emission Cntrl Upgrades	2.370%	403SP	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$3,257	$39,087
Hunter U1 SO2 Upgrades	2.370%	403SP	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$2,481	$28,536
JB U2 Turbine Upgrade HP/IP/LP	2.370%	403SP	$0	$0	$0	$0	$0	$298	$596	$596	$596	$596	$596	$596	$596	$298
Hunter 303 Turbine Upgrade HP/IP/LP	2.370%	403SP	$596	$596	$596	$596	$596	$596	$596	$596	$596	$596	$596	$596	$596	$7,146
INU 4.1.1/4.1.2 Soda Springs Fish Passag	1.964%	403HP	$861	$861	$861	$861	$861	$861	$861	$861	$861	$861	$861	$861	$861	$7,318
ILR 4.4 Swift Fish Collector	1.964%	403HP	$1,316	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$2,632	$14,476
ILR 4.3 Merwin Upstream Collect & Trans	1.964%	403HP	$115	$230	$230	$230	$230	$230	$230	$230	$230	$230	$230	$230	$230	$1,267
Ashton Dam Seepage Control	2.749%	403HP	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$1,243	$8,082
IRO Prospect Instream Flow / Automation	1.964%	403HP	$439	$439	$439	$439	$439	$439	$439	$439	$439	$439	$439	$439	$439	$2,851
Clover Substation	1.890%	403TP	$422	$844	$844	$844	$844	$844	$844	$844	$844	$844	$844	$844	$844	$4,643
Lake Side 2 Interconnect	1.890%	403TP	$0	$0	$0	$0	$0	$475	$950	$950	$950	$950	$950	$950	$950	$475
Accumulated Depreciation																
Naughton U2 Flue Gas Desulfurization Sys		108SP	$63,708	$68,427	$73,146	$77,865	$82,584	$87,303	$92,022	$96,742	$101,461	$106,180	$110,899	$115,618	$120,337	$58,989
Naughton U1 Flue Gas Desulfurization Sys		108SP	$30,644	$34,730	$38,816	$42,902	$46,987	$51,073	$55,159	$59,245	$63,331	$67,417	$71,503	$75,588	$79,674	$26,558
DJ U4 SO2 & PM Emission Cntrl Upgrades		108SP	$27,687	$30,944	$34,201	$37,458	$40,716	$43,973	$47,230	$50,487	$53,745	$57,002	$60,259	$63,516	$66,774	$24,429
Hunter U1 SO2 Upgrades		108SP	$16,129	$18,611	$21,092	$23,573	$26,055	$28,536	$31,018	$33,499	$35,980	$38,462	$40,943	$43,425	$45,906	$13,743
JB U2 Turbine Upgrade HP/IP/LP		108SP	$0	$0	$0	$0	$0	$298	$893	$1,489	$2,084	$2,680	$3,275	$3,871	$4,467	$23
Hunter 303 Turbine Upgrade HP/IP/LP		108SP	$5,062	$5,658	$6,253	$6,849	$7,444	$8,040	$8,635	$9,231	$9,826	$10,422	$11,017	$11,613	$12,209	$4,467
INU 4.1.1/4.1.2 Soda Springs Fish Passag		108HP	$3,013	$3,874	$4,735	$5,596	$6,457	$7,318	$8,178	$9,039	$9,900	$10,761	$11,622	$12,483	$13,344	$2,682
ILR 4.4 Swift Fish Collector		108HP	$1,316	$3,948	$6,580	$9,212	$11,844	$14,476	$17,108	$19,740	$22,372	$25,004	$27,636	$30,268	$32,900	$3,644
ILR 4.3 Merwin Upstream Collect & Trans		108HP	$115	$345	$576	$806	$1,036	$1,267	$1,497	$1,727	$1,958	$2,188	$2,418	$2,648	$2,879	$319
Ashton Dam Seepage Control		108HP	$1,865	$3,109	$4,352	$5,595	$6,839	$8,082	$9,326	$10,569	$11,813	$13,056	$14,299	$15,543	$16,786	$2,343
IRO Prospect Instream Flow / Automation		108HP	$658	$1,097	$1,535	$1,974	$2,413	$2,851	$3,290	$3,729	$4,167	$4,606	$5,045	$5,483	$5,922	$827
Clover Substation		108TP	$422	$1,266	$2,111	$2,955	$3,799	$4,643	$5,488	$6,332	$7,176	$8,021	$8,865	$9,709	$10,553	$1,169
Lake Side 2 Interconnect		108TP	$0	$0	$0	$0	$0	$475	$1,425	$2,375	$3,324	$4,274	$5,224	$6,174	$7,124	$37

Derivation of UAE Adjustment To Remove a Portion of the Contingency Costs included in Pro Forma Capital Additions

Contingency Costs Included in Rate Case:

Project Description	FERC Account	Factor	In-Service Date	Amount	Source
Naughton U2 Flue Gas Desulfurization Sys	312	SG	Nov-11	$3,565,848	RMP Response to UAE Data Request 4.1 Attachment.
Naughton U1 Flue Gas Desulfurization Sys	312	SG	May-12	$3,087,357	RMP Response to UAE Data Request 4.1 Attachment.
DJ U4 SO2 & PM Emission Cntrl Upgrades	312	SG	Apr-12	$2,461,244	RMP Response to UAE Data Request 4.1 Attachment.
Hunter U1 SO2 Upgrades	312	SG	Jun-12	$1,875,000	RMP Response to UAE Data Request 4.1 Attachment.
JB U2 Turbine Upgrade HP/IP/LP	312	SG	May-13	$450,000	RMP Response to UAE Data Request 4.1 Attachment.
Hunter 303 Turbine Upgrade HP/IP/LP	312	SG	Apr-12	$450,000	RMP Response to UAE Data Request 4.1 Attachment.
INU 4.1.1/4.1.2 Soda Springs Fish Passag	332	SG-P	Sep-12	$785,000	RMP Response to UAE Data Request 4.1 Attachment.
ILR 4.4 Swift Fish Collector	332	SG-P	Dec-12	$2,400,000	RMP Response to UAE Data Request 4.1 Attachment.
ILR 4.3 Merwin Upstream Collect & Trans	332	SG-P	Dec-12	$210,000	RMP Response to UAE Data Request 4.1 Attachment.
Ashton Dam Seepage Control	332	SG-U	Nov-12	$810,000	RMP Response to UAE Data Request 4.1 Attachment.
IRO Prospect Instream Flow / Automation	332	SG-P	Nov-12	$400,000	RMP Response to UAE Data Request 4.1 Attachment.
Clover Substation	355	SG	Dec-12	$800,000	RMP Response to UAE Data Request 4.1 Attachment.
Lake Side 2 Interconnect	355	SG	May-13	$900,000	RMP Response to UAE Data Request 4.1 Attachment.
Total				$18,194,449	

UAE Recommended Disallowance Percentage		67%

Derivation of UAE Adjustment To Remove a Portion of the Contingency Costs included in Pro Forma Capital Additions

Schedule M and Accumulated Deferred Income Tax Impacts

	Depreciable / 20 Yr MACRS					
2011 Projects	2011 Jan.-Jun.	2011 Jul.-Dec.	2012 Jan.-Jun.	2012 Jul.-Dec.	2013 Jan.-Jun.	2013 Jul.-Dec.
Capital Addition ($)		$2,389,118				
Applicable Amount Per Period ($)	$1,194,559	$1,194,559				
Book Depreciation Expense ($)		$7,079	$28,315	$28,315	$28,315	$28,315
Applicable Amount Per Period ($)	$3,539	$3,539	$28,315	$28,315	$28,315	$28,315
Monthly Book Depreciation Expense ($)	$590	$590	$4,719	$4,719	$4,719	$4,719
Applicable Bonus Tax Depreciation (%)	50%	50%				
Applicable Amortization/MACRS (%)		3.750%		7.219%		14.286%
Bonus Tax Depreciation Expense Per Period ($)	$597,280	$597,280				
MACRS Tax Depreciation Expense ($)	$22,398	$22,398	$43,118	$43,118	$85,326	$85,326
Monthly Tax Depreciation Expense ($)	$103,280	$103,280	$7,186	$7,186	$14,221	$14,221
Tax/Book Depreciation Expense Difference ($)	$616,138	$616,138	$14,803	$14,803	$57,011	$57,011
Monthly Tax/Book Depreciation Exp. Difference ($)	$102,690	$102,690	$2,467	$2,467	$9,502	$9,502
Tax Rate (%)	37.95%	37.95%	37.95%	37.95%	37.95%	37.95%
Deferred Income Tax Expense ($)	$233,831	$233,831	$5,618	$5,618	$21,636	$21,636
Monthly Deferred Income Tax Expense ($)	$38,972	$38,972	$19,954	$936	$2,271	$3,606

	Depreciable / 20 Yr MACRS					
2012 Projects	2011 Jan.-Jun.	2011 Jul.-Dec.	2012 Jan.-Jun.	2012 Jul.-Dec.	2013 Jan.-Jun.	2013 Jul.-Dec.
Capital Addition ($)			$5,275,313	$3,621,350		
Applicable Amount Per Period ($)			$4,448,331	$4,448,331		
Book Depreciation Expense ($)			$17,001	$69,910	$100,018	$100,018
Applicable Amount Per Period ($)			$43,456	$43,456	$100,018	$100,018
Monthly Book Depreciation Expense ($)			$7,243	$7,243	$16,670	$16,670
Applicable Bonus Tax Depreciation (%)			50%	50%		
Applicable Amortization/MACRS (%)				3.750%		7.219%
Bonus Tax Depreciation Expense Per Period ($)			$2,224,166	$2,224,166		
MACRS Tax Depreciation Expense ($)			$83,406	$83,406	$160,563	$160,563
Monthly Tax Depreciation Expense ($)			$384,595	$384,595	$26,760	$26,760
Tax/Book Depreciation Expense Difference ($)	$0	$0	$2,264,116	$2,264,116	$60,545	$60,545
Monthly Tax/Book Depreciation Exp. Difference ($)			$377,353	$377,353	$10,091	$10,091
Tax Rate (%)			37.95%	37.95%	37.95%	37.95%
Deferred Income Tax Expense ($)	$0	$0	$859,255	$859,255	$22,977	$22,977
Monthly Deferred Income Tax Expense ($)	$0	$0	$71,605	$143,209	$73,519	$3,830

	Depreciable / 20 Yr MACRS					
2013 Projects	2011 Jan.-Jun.	2011 Jul.-Dec.	2012 Jan.-Jun.	2012 Jul.-Dec.	2013 Jan.-Jun.	2013 Jul.-Dec.
Capital Addition ($)					$904,500	
Applicable Amount Per Period ($)					$452,250	$452,250
Book Depreciation Expense ($)					$2,318	$9,272
Applicable Amount Per Period ($)					$5,795	$5,795
Monthly Book Depreciation Expense ($)					$966	$966
Applicable Bonus Tax Depreciation (%)					50%	50%
Applicable Amortization/MACRS (%)						3.750%
Bonus Tax Depreciation Expense Per Period ($)					$226,125	$226,125
MACRS Tax Depreciation Expense ($)					$8,480	$8,480
Monthly Tax Depreciation Expense ($)					$39,101	$39,101
Tax/Book Depreciation Expense Difference ($)	$0	$0	$0	$0	$228,810	$228,810
Monthly Tax/Book Depreciation Exp. Difference ($)					$38,135	$38,135
Tax Rate (%)					37.95%	37.95%
Deferred Income Tax Expense ($)	$0	$0	$0	$0	$86,836	$86,836
Monthly Deferred Income Tax Expense ($)	$0	$0	$0	$0	$7,236	$14,473

Total Deferred Income Tax Expense ($)	$233,831	$233,831	$864,873	$864,873	$131,449	$131,449
Accumulated Deferred Income Tax Expense ($)	$233,831	$467,661	$1,332,534	$2,197,406	$2,328,856	$2,460,305

Rocky Mountain Power

Utah Retail Operations
UAE Casper Lease Buy-out Rate Base Allocation Correction Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Casper Lease Buy-out Allocation Correction (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	10,875
24	Income Taxes - State	1,478
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	12,353
29		
30	Operating Rev For Return:	(12,353)
31		
32	Rate Base:	
33	Electric Plant In Service	(1,264,181)
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	167
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	(1,264,015)
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	-
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	-
55		
56	Total Rate Base:	(1,264,015)
	UTAH REV. REQ'T CHANGE	(141,442)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Casper Lease Buy-out Rate Base Allocation Correction Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($1,264,015) x 7.906% x 1.6151
≈ ($161,393)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Casper Lease Buy-out Rate Base Allocation Correction Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= $12,353 x 1.6151
≈ $19,951

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
General Plant Additions Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to General Plant:					
Casper Service Center Lease Buy-out	397	(2,950,000)	SO	42.854%	(1,264,181)
Casper Service Center Lease Buy-out	397	2,950,000	WY	0.000%	0

Data Sources : Exhibit RMP__(SRM-3), page 8.6.27; RMP Response to OCS Data Request 8.26 (d).

Rocky Mountain Power

Utah Retail Operations
UAE Accumulated Deferred Income Tax Update Rate Base Adjustment
Twelve Months Ending May 31,2013

Line No.	(A)	Utah Allocated Accumulated Deferred Income Tax Update (B)
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19	Total O&M Expenses	-
20	Depreciation	-
21	Amortization	-
22	Taxes Other Than Income	-
23	Income Taxes - Federal	36,683
24	Income Taxes - State	4,985
25	Income Taxes - Def Net	-
26	Investment Tax Credit Adj.	-
27	Misc Revenue & Expense	-
28	Total Operating Expenses:	41,668
29		
30	Operating Rev For Return:	(41,668)
31		
32	Rate Base:	
33	Electric Plant In Service	-
34	Plant Held for Future Use	-
35	Misc Deferred Debits	-
36	Elec Plant Acq Adj	-
37	Nuclear Fuel	-
38	Prepayments	-
39	Fuel Stock	-
40	Material & Supplies	-
41	Working Capital	562
42	Weatherization Loans	-
43	Misc Rate Base	-
44	Total Electric Plant:	562
45		
46	Rate Base Deductions:	
47	Accum Prov For Deprec	-
48	Accum Prov For Amort	-
49	Accum Def Income Tax	(4,264,163)
50	Unamortized ITC	-
51	Customer Adv For Const	-
52	Customer Service Deposits	-
53	Misc Rate Base Deductions	-
54	Total Rate Base Deductions	(4,264,163)
55		
56	Total Rate Base:	(4,263,601)
	UTAH REV. REQ'T CHANGE	(477,092)

Utah Revenue Requirement Impact:

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Accumulated Deferred Income Tax Update Rate Base Adjustment (rate base portion) is:

= rate base adj. x RMP rate of return x tax gross-up factor
= ($4,263,601) x 7.906% x 1.6151
≈ ($544,389)

Taken in the sequence of adjustments shown in Table KCH-1, the revenue requirement impact of reflecting UAE's Accumulated Deferred Income Tax Update Rate Base Adjustment (income statement portion) is:

= -Operating rev. for return adj. x tax gross-up factor
= $41,668 x 1.6151
≈ $67,298

Utah Association of Energy Users (UAE)
Utah General Rate Case - May 2013
Accumulated Deferred Income Tax Update Adjustment

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED
Adjustment to ADIT:					
ADIT Balance	282	(9,881,114)	SG	43.155%	(4,264,163)

Data Source: CONF RMP Response to OCS Data Request 26.1.

UAE Exhibit RR 1.17

[Confidential]

UAE Exhibit RR 1.18

[Confidential]

UE-246/PacifiCorp
April 9, 2012
ICNU Data Request 2.28

ICNU Data Request 2.28

Please identify the total legal department costs for 2006-2011, and expected legal department costs for 2010-2015. Please provide a categorical breakdown and description of PacifiCorp's legal department costs.

Response to ICNU Data Request 2.28

The Company objects to this request to the extent that it requests information related to time periods not relevant to these proceedings and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Confidential Attachment 2.28 for actual legal department costs and outside legal fees for calendar years 2006 through 2011. The budgeted information for 2012 is also provided. The information provided in Confidential Attachment ICNU 2.28 is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

The Company has not budgeted at the same level of granularity beyond 2012. The legal department costs for 2012-2015 are expected to escalate due to inflation and will fluctuate based on the number of matters processed.

UE-246/PacifiCorp
April 9, 2012
ICNU Data Request 2.36

ICNU Data Request 2.36

Please provide an explanation and all supporting information regarding the difference between the amount of outside legal expenses included in the test period, and the calendar year outside legal expense for 2008, 2009, 2010 and 2011. For example, please identify specific cost categories, cases or matters that are expected to differ.

Response to ICNU Data Request 2.36

Please refer to Confidential Attachment ICNU 2.36 for actual total company outside legal expenses for 2008 through 2011, and estimated total company legal expenses for the 2013 test period.

The information provided in Confidential Attachment ICNU 2.36 is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

Calendar year 2008 included environmental litigation expenses associated with McConnell v PacifiCorp that did not continue beyond 2008. Litigation was commenced in 2010 by Deseret Power against PacifiCorp. Continued litigation associated with seeking to terminate the Grant P.U.D. contract resulted in higher legal expenses in CY2010. Taylor v. Saberhagen was scheduled for trial in 2010, which the court then postponed, *sua sponte*, days before trial. This expected trial led to higher legal expenses in CY2010. Continued litigation associated with Wah Chang v PacifiCorp resulted in higher legal expenses in CY2010.

CONFIDENTIAL

PacifiCorp Legal Department Costs

Legal Department Costs (Above the Line):							PLAN
	CY 2006	CY 2007	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012
Category	$	$	$	$	$	$	$
Total Labor Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employee Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials & Supplies	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts & Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
External Legal Fees	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OMAG Expenses - Intercompany	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Legal Department Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Legal Department Costs (Above the Line):							
Category	CY 2006	CY 2007	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012
External Legal Fees	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Non-Legal Department Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Legal Costs	15,685,803	16,914,405	21,161,922	15,840,759	20,083,049	23,751,979	#VALUE!

Fees - CY2008 - CY 2011 and 12 ME June 2011

FERC Account	Cost Object Description	CY2008 $	CY2009 $	CY2010 $	CY2011 $	12ME June 2011 $