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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. 10-035-124**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT]

[Non-Confidential Version]

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

DATED this 26th day of May, 2011.

/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 26th day of May, 2011, on the following:

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BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Non-Confidential Version

[Redacted confidential testimony highlighted]

Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 10-035-124

[Revenue Requirement]

May 26, 2011

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. Are you the same Kevin C. Higgins who testified on behalf of UAE in the test period phase of this docket?

A. Yes, I am.

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-six 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 110 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, 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.

A more detailed description of my qualifications is contained in Attachment A, attached to my prefiled direct test period testimony, filed previously in this docket.

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").

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

A. In its direct filing, RMP is proposing a revenue increase of $232,416,309, or 13.7 percent on an annual basis. It should be noted, however, that RMP's proposed revenue increase does not include the effects in current rates of Schedule 97 or Schedule 98, each of which is scheduled to expire at the start of, or close to the start of, the rate effective period.

Schedule 97 is a temporary percentage rider approved in Docket No. 10-035-89 that is recovering certain deferred costs associated with RMP's first Major Plant Additions case. It is levied at an average rate of 1.56 percent for eight months; as such, it is scheduled to recover $15.7 million and to terminate on August 31, 2011, shortly before the rate effective period in this case.

Schedule 98 is also a temporary percentage rider approved in Docket No. 10-035-89 that is *crediting* customers for 2011 REC revenues in the amount of approximately $3.0 million per month (Utah). It is providing an average credit of 2.39 percent and is scheduled to terminate at the start of the rate effective period in this case.

As neither of these riders is included in RMP's presentation of its revenue increase, the Commission should be aware that RMP's proposed rate increase, *as experienced by customers*, will include the net impact of the Schedule 97 charge and Schedule 98 credit terminating, which together represent an average rate increase to customers of 0.83 percent (relative to rates paid by customers over the first eight months of 2011). From a customer rate impact standpoint, this average increase of 0.83 percent is incremental to the 13.7 percent revenue requirement increase indicated by RMP.

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

A. My recommended revenue requirement adjustments total **$95,021,912** for the test period ending June 2012, plus an additional **$46,209,511** relating to deferrals from a prior period, for a total adjustment of **$141,231,422** in the rate effective period. These adjustments are presented in Table KCH-1 below. My recommended adjustments are as follows:

(1) I recommend using the Rolled-in inter-jurisdictional allocation method, without a premium, to set rates in this case. This adjustment reduces the Utah revenue requirement by approximately **$15,013,228** relative to RMP's filed

case. All subsequent adjustments presented in my testimony are estimated using the Rolled-in method.

(2) I recommend that the Commission deny RMP's proposal to adjust the depreciation rates for the Klamath Hydroelectric Project assets at this time, as such an adjustment is premature. This adjustment reduces RMP's Utah revenue requirement by approximately **$1,713,249**.

(3) I recommend an adjustment to RMP's revenue requirement in this case to recognize a revenue credit attributable to the contributions from Oregon and California customers to fully fund RMP's maximum obligation for the cost of dam removal for the Klamath Hydroelectric Project. This adjustment exactly offsets the cost of removal allocated to Utah by RMP. This adjustment reduces RMP's Utah revenue requirement by approximately **$7,449,210**.

(4) I recommend using a REC sales revenue projection of $110.5 million for the test period. This adjustment reduces Utah's revenue requirement by approximately **$33,029,029**.

(5) I recommend reversing a proposed RMP adjustment to ancillary revenue associated with an expiring contract. This adjustment reduces Utah's revenue requirement by approximately **$1,063,097**.

(6) I recommend that a portion of RMP's environmental upgrade expenditures be determined to be imprudent because they are not cost effective, as explained by UAE witness Howard Gebhart. The Utah revenue requirement reduction, by facility, associated with this adjustment is as follows:

Hunter 1 Scrubber Upgrade	$294,824
Hunter 2 Scrubber Upgrade	$1,820,735
Huntington 1 Scrubber Upgrade	$2,513,687
Dave Johnston 3 SO_2 Project	$3,708,625
TOTAL	**$8,337,870**

(7) I recommend that the Commission approve an overall wage and benefit expense equal to the Company's Calendar Year 2010 actual expense plus 0.75 percent on an annualized basis, which is an increase of 1.13 percent applicable to the test period. Even though 2010 actual wage and benefit expense declined relative to 2009, on average, the year-over-year increase in RMP's wage and benefit expenses has been running about 0.75 percent between 2007 and 2010. I recommend approval of wage and benefit expense in rates that is consistent with this three-year trend in RMP's wage and benefits costs. This adjustment reduces RMP's Utah revenue requirement by approximately **$8,430,269**.

(8) I recommend adjusting RMP's non-labor O&M expense to remove its projected cost escalation increase for the test period. This adjustment reduces Utah revenue requirement by approximately **$7,466,328**.

(9) Based on the analysis presented in the direct testimony of UAE witness Jeff J. Fishman, I am recommending that projected expenses stemming from RMP's gas swap transactions associated with a hedged position greater than 75 percent of the Company's projected monthly gas requirement in the test period

be excluded from cost recovery. This adjustment reduces RMP's Utah revenue requirement by approximately **$12,519,631**.

(10) One hundred percent of the REC revenues deferred since February 22, 2010 should be credited to customers in this proceeding. For the deferral period running from February 22, 2010 through December 31, 2010, a sur-credit should be established at the start of the rate effective period in this case that will refund to customers Utah's share of the difference between actual REC revenues booked during the period and the REC revenues reflected in base rates approved by the Commission in its decision in Docket No. 09-035-23, plus interest. I recommend that this balance be credited back to customers over the one-year period September 21, 2011 through September 20, 2012. I estimate that the REC deferral for this period, inclusive of interest, is **$46,209,511**.

(11) Utah customers should also be credited with a true-up to actual incremental REC revenue for the REC deferral period running from January 1, 2011 through the start of the rate effective period (presumed to be September 21, 2011). I recommend that this balance be credited back (or charged) to customers after the end of the one-year credit period described above. The amount of this sur-credit or surcharge for Utah customers is Utah's share of the difference between actual REC revenues booked during this period and the REC revenues reflected during this period in rates, including those assumed in base rates in the 2009 general rate case and those collected through Schedule 98 and Schedule 40,

the latter of which incorporates incremental revenue associated with the Dunlap I wind facility approved as part of the MPA II Docket, plus interest.

(11) Whether and how customers should be credited with REC revenues booked by RMP prior to February 22, 2010, will presumably be addressed following resolution of the Application filed by UIEC in Docket No. 11-035-46. Accordingly, I do not specifically address that period in this testimony, other than to address the circumstances and factors relevant to that time period and to note the similarity of the same to the post-February 22, 2010 period.

Table KCH-1

Summary of Revenue Requirement Impact of UAE Adjustments

	Adjustment
Adjustment to Reflect Rolled-In Allocation	**(15,013,228)**
Klamath Hydroelectric Depreciation	**(1,713,249)**
Klamath Surcharge Situs Adjustment	**(7,449,210)**
Test Period REC Revenue Adjustment	**(33,029,029)**
Ancillary Revenue Adjustment	**(1,063,097)**
Environmental Projects Disallowance	
Hunter Unit No. 1 Scrubber Upgrade	**(294,824)**
Hunter Unit No. 2 Scrubber Upgrade	**(1,820,735)**
Huntington Unit No. 1 Scrubber Upgrade	**(2,513,687)**
Dave Johnston Unit No. 3 SO_2 Project	**(3,708,625)**
Wage and Benefit Expense Adjustment	**(8,430,269)**
O&M Escalation Adjustment	**(7,466,328)**
Natural Gas SWAP Disallowance	**(12,519,631)**
Sub-Total UAE Test Period Adjustments	**(95,021,912)**
2010 Deferred REC Revenue (Feb. 22, 2010 - Dec. 31, 2010)	**(46,209,511)**
Total UAE Rate Effective Period Adjustments	**($141,231,422)**

INTER-JURISDICTIONAL COST ALLOCATION: MOVE TO ROLLED-IN

Q. What is the role of inter-jurisdictional cost allocation in an RMP general rate case?

A. Because RMP is a multi-jurisdictional utility, it is necessary to allocate the Company's system costs among its various jurisdictions when conducting a general rate case. An inter-jurisdictional cost allocation methodology must be used for this purpose.

Q. What inter-jurisdictional cost allocation methodologies have been utilized in Utah in recent rate cases?

A. Rate cases filed since 2004 have shown inter-jurisdictional cost allocation results using both the Rolled-in method and the Revised Protocol method. Prior to that, Utah had used the Rolled-in method for several years. While there are several specific differences between these two methods, the most essential difference is that the Revised Protocol removes the benefits and costs of the west-side hydro system from the Utah revenue requirement, whereas the Rolled-in method allocates the benefits and costs of all system resources, including hydro, in a manner that is proportionate to jurisdictional load. Pursuant to a Stipulation that was conditionally approved by the Commission on December 14, 2004 in Docket No. 02-035-04, the revenue requirement for the Utah jurisdiction is determined by selecting the lesser of two revenue requirement calculations: one which uses the Revised Protocol method plus a premium (currently 0.25%, applicable to the first nine months of the test period) or one using the Rolled-in method plus a premium (currently 1.0%).

Q. Which inter-jurisdictional cost allocation method did RMP use in this proceeding?

A. Consistent with each previous rate case filing in Utah made after 2004, RMP filed its case using the Revised Protocol method and the Rolled-in method. According to the Company's filing, Revised Protocol plus a premium of 0.25% applied to the first nine months of the test period produces a lower revenue requirement than Rolled-in plus a premium of 1.0%; consequently, RMP proposes to set Utah rates using the former. In addition, RMP's filing provides revenue requirement results using an alternative proposed allocation method, the "2010 Protocol," which has been under discussion among RMP stakeholders as part of the Multi-State Process ("MSP"), and is the subject of a March 2011 filing by RMP in Docket No. 02-035-04. A number of Utah parties, including UAE, are engaged in discussions with RMP on this issue, but no agreement or Commission acceptance of this methodology has been reached.

Q. What inter-jurisdictional cost allocation method should be used for setting rates in this case?

A. I recommend using the Rolled-in method, without a premium, to set rates in this case.

Q. Please explain your recommendation.

A. In its Order in Docket No. 09-035-15, issued March 3, 2011, the Commission approved an Energy Balancing Account ("EBA") for RMP. UAE has consistently maintained that if an EBA is adopted in Utah, as a condition of such adoption and for at least as long as an EBA remains in effect, inter-jurisdictional costs allocated to Utah should be set based on the Rolled-in allocation methodology. The reason for this linkage is that an EBA subjects Utah to hydro-related risk: a poor hydro year requires the procurement of replacement power, negatively impacting customers through the EBA. Yet a defining characteristic of the Revised Protocol method is that the benefits of west-side hydro resources are removed from the Utah revenue requirement.

In 2004, when the MSP Stipulation was filed and conditionally approved, there was no EBA in Utah. In my opinion, the adoption of an EBA subjecting Utah customers to hydro-related risk is a materially-changed circumstance, and I believe the continued use of the Revised Protocol to determine Utah's allocated share of system revenue requirements in conjunction with an EBA would produce unjust and unreasonable results. In short, it would be fundamentally unreasonable for Utah customers to be fully subjected to hydro-related risk through the EBA while being denied a large proportion of system hydro benefits through the Revised Protocol allocation method.

In contrast, the Rolled-in method apportions to Utah a system hydro benefit that is proportionate to Utah's load. By re-adopting the Rolled-in method, without a premium, the system hydro benefits credited to Utah would be consistent with the system hydro risk allocated to Utah through the EBA.

Q. How does your recommendation comport with the MSP?

A. While adoption of my recommendation in this docket might appear to have implications for MSP discussions among representatives of PacifiCorp's jurisdictions, it is not intended to preclude or preempt a new, negotiated MSP resolution among those parties. Rather, my recommendation is tied to RMP's voluntary pursuit of an EBA; thus, my recommendation is more akin to the adoption of the MSP rate mitigation cap in the 2004 Stipulation, which governs inter-jurisdictional cost allocation to Utah, in co-existence with the MSP Revised Protocol among the signatory states.

Q. As a party to the Utah MSP Stipulation dated June 28, 2004, in Docket 02-035-04 and as a party that supported ratification of the Revised Protocol in that docket, UAE agreed to work in good faith to address inter-jurisdictional issues being considered by the MSP Standing Committee. Has UAE done so?

A. Yes. UAE, along with a number of other Utah participants, has actively monitored and participated in MSP Standing Committee activities over the past several years to address, among other things, concerns of Utah parties regarding continued application of Revised Protocol in Utah. In addition, UAE informed the MSP Standing Committee that adoption of an EBA in Utah would constitute a changed circumstance that would cause it to conclude in good faith that Revised Protocol would no longer produce just and reasonable results for Utah, and that

UAE intended to propose that adoption of any kind of an EBA should be conditioned upon simultaneous adoption of the Rolled-in allocation methodology for all inter-jurisdictional cost allocation ratemaking purposes in Utah.

Q. What is the revenue requirement impact of your recommendation to re-adopt the Rolled-in inter-jurisdictional cost allocation methodology?

A. Adoption of the Rolled-in inter-jurisdictional cost allocation methodology, without a premium, reduces the Utah revenue requirement by approximately **$15,013,228** relative to RMP's filed case. This adjustment is presented in UAE Exhibit RR 1.1.

All subsequent adjustments presented in my testimony are estimated using the Rolled-in method.

KLAMATH HYDROELECTRIC PROJECT

Q. Please explain your adjustments related to the Klamath Hydroelectric Project.

A. RMP is proposing several adjustments pertaining to the Klamath Hydroelectric Project. The Company's rationale for these changes is tied to the Klamath Hydroelectric Settlement Agreement ("KHSA"). I recommend two adjustments relating to the Company's proposal: denial of RMP's proposal to change the depreciation rate for this project and 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.

Q. What is the KHSA?

A. The KHSA is an agreement among PacifiCorp, the U.S. Government, the State of Oregon, the State of California 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.

As described by RMP witness Dean S. Brockbank, 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 must determine by March 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. 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 $73.7 million system-wide, which RMP proposes to include in rate base and amortize over nine years. Utah's annual share of this cost is approximately $7.8 million.[1] Note that pursuant to the Revised Protocol allocation method filed by RMP, much of this cost is removed through the Embedded Cost Differential, which removes west-side hydro benefits and costs from Utah. However, under the Rolled-in method, Utah retains this allocation of cost. The $15 million revenue requirement reduction for Utah associated with the Rolled-in method, discussed above, already takes this cost into account. Although I have some concerns about PacifiCorp's request to begin collecting these costs in this rate case, I am not recommending any adjustments relative to these costs at this time.
- Cost of dam removal. Under the Revised Protocol, this cost is situs assigned to Oregon and California. Under the Rolled-in method, Utah retains this allocation of cost, which is already taken into account in the aforementioned $15 million revenue requirement reduction for Utah associated with the Rolled-in method.
- 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.

[1] Approximately $3.55 million in depreciation expense plus $4.25 million in return on rate base.

Q. Do you have any comments with respect to the treatment of these costs in this rate proceeding?

A. Yes. 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 conceivably may not 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 either been approved or appears close to approval by those states' regulatory commissions, a second major funding source, up to $250 million in bonds (or other financing) issued by the State of California, has yet to be enacted. In light of significant 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 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 Agreement is speculative and uncertain.

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 1.2, this adjustment reduces RMP's Utah revenue requirement by **$1,713,249**.

Q. Do you have any other comments with respect to the treatment of Klamath-related costs in this rate proceeding?

A. Yes. Just as it is premature to change the depreciation rates for the Klamath Hydroelectric Project assets at this time, it is also premature to charge Utah customers for cost of dam removal. 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 been (or are close to being) 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 moot. Therefore, I recommend that RMP's revenue requirement in this case be adjusted to recognize a revenue credit attributable to the contributions 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 1.3, this adjustment reduces RMP's Utah revenue requirement by **$7,449,210**.

RENEWABLE ENERGY CREDITS

Q. Generally, what role do renewable energy credits play in setting rates for RMP?

A. RMP is able to sell the renewable energy "attributes" associated with the generation output of certain renewable generation facilities such as wind, geothermal, and small hydro plants. These attributes have value to other utilities and other RMP states that require specified amounts of renewable energy pursuant to state statutes and regulations. When these attributes are sold in the marketplace, the exchanged product has come to be known as Renewable Energy Credits ("RECs") or Green Tags. Because REC sales are made using assets that are paid for by customers, the revenues from REC sales are appropriately treated as a revenue credit against the revenue requirement recovered from customers.

Q. What is the current level of REC revenues reflected in Utah rates?

A. Base rates set in the last general rate case reflect REC revenue of $18.6 million per year on a Company-wide basis.[2] Utah's share of these revenues is approximately $9.9 million. This level of REC revenues was approved by the Commission in Docket No. 09-035-23. In addition, as part of the stipulation approved by the Commission in Docket No. 10-035-89 ("MPA II"), a sur-credit that recognizes approximately $3 million per month (Utah-allocated share) has been recognized in rates via Schedule 98 since January 1, 2011. In addition, this stipulation recognizes $0.76 million of REC revenues from the Dunlap I wind facility in Utah rates effective January 1, 2011, implemented through Schedule 40. Schedules 98 and 40 are intended to be in effect until the start of the rate-effective period in this case.

Q. You have previously testified in the EBA case, Docket No. 09-035-15 and the last Major Plant Addition (MPA II) case, Docket No. 10-035-89, regarding the appropriate ratemaking treatment of REC revenues that are being deferred pursuant to Commission Order as a result of UAE's Application for deferred accounting of incremental REC revenue in Docket No. 10-035-14. How does that discussion relate to your testimony in this proceeding?

A. I will address the appropriate ratemaking treatment of these deferred REC revenues below, in a separate section of my direct testimony in this case. <u>This section</u> of my testimony will address only the appropriate level of REC revenues

[2] Unless explicitly stated otherwise, all references to REC sales values in my testimony will be on a total Company basis.

that should be projected for the test period in this case, from July 1, 2011 to June 30, 2012.

Q. Please proceed. What level of REC revenues has RMP projected for the test period?

A. In its filing, RMP's projects $55.7 million of REC revenues in the test period. This is significantly less than actual base period (ending June 2010) REC revenues of approximately $98.5 million. It is also significantly less than actual calendar year 2010 REC revenues of $101.1 million. In his direct testimony, RMP witness Stefan Bird attributes a large part of this differential to uncertainty in the California market associated with the pendency of a major ruling by the California Public Utilities Commission ("CPUC") concerning the eligibility of using out-of-state resources for compliance with California renewable energy requirements. According to Mr. Bird, prior to the issuance of CPUC Decision 11-01-025 (which was issued on January 14, 2011, shortly before RMP's filing), the California REC market had become "paralyzed." The subsequent issuance of CPUC Decision 11-01-025, which authorizes the use of tradable renewable energy credits ("TRECs") for compliance with a portion of California Renewables Portfolio Standard ("RPS") requirements, and lifts a stay on the use of TRECs imposed by a prior CPUC decision, has now alleviated a significant portion of the uncertainty concerning access to the California market referenced by Mr. Bird, and is allowing transactions to proceed.

Q. What further developments have occurred in the California market since the filing of RMP's direct testimony?

A. On March 1, 2011, the three large California investor-owned utilities ("IOUs") submitted their RPS compliance reports as mandated by CPUC Decision 05-07-039. Those compliance reports identify "historic performance in the RPS program, current year targets and procurement data, and forecast targets and procurement data for at least three years."[3] Based on renewable procurement data in these reports, the utilities expect to continue to utilize TRECs in their RPS portfolios at higher levels than 2010, with steady growth through at least year 2014. Current and forecasted TREC procurement details for Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E) are shown in Table KCH-2, below.

Table KCH-2

California IOU TREC Forecast[4]

SCE Procurement Detail	**2010**	**2011**	**2012**	**2013**	**2014**
Existing TREC Contracts:	1,331,598	1,070,314	2,014,233	2,787,410	2,787,410
TREC Contracts Pending Approval:	0	194,840	835,374	1,046,347	892,288
Total TREC Contracts:	**1,331,598**	**1,265,154**	**2,849,607**	**3,833,757**	**3,679,698**

PG&E Procurement Detail	**2010**	**2011**	**2012**	**2013**	**2014**
Existing TREC Contracts:	1,489,954	2,718,594	2,152,411	2,385,230	2,671,550
TREC Contracts Pending Approval:	1,429,525	1,613,650	605,000	605,000	605,000
Total TREC Contracts:	**2,919,479**	**4,332,244**	**2,757,411**	**2,990,230**	**3,276,550**

SDG&E Procurement Detail	**2010**	**2011**	**2012**	**2013**	**2014**

[3] Source: http://www.cpuc.ca.gov/PUC/energy/Renewables/compliance.htm

[4] Source: IOUs' RPS Compliance Reports, March 1, 2011. Available at www.cpuc.ca.gov/PUC/energy/Renewables/compliance.htm

Existing TREC Contracts:	724,863	656,441	635,000	635,000	635,000
TREC Contracts Pending Approval:	0	0	0	0	0
Total TREC Contracts:	**724,863**	**656,441**	**635,000**	**635,000**	**635,000**

Total: SCE, PG&E and SDG&E Combined Procurement Detail	**2010**	**2011**	**2012**	**2013**	**2014**
Existing TREC Contracts:	3,546,415	4,445,349	4,801,644	5,807,640	6,093,960
TREC Contracts Pending Approval:	1,429,525	1,808,490	1,440,374	1,651,347	1,497,288
Total TREC Contracts:	**4,975,940**	**6,253,839**	**6,242,018**	**7,458,987**	**7,591,248**

Q. What inferences can you draw regarding the continued demand in the California market for TRECs during the test period in this case?

A. As shown in Table KCH-2, the projected demand in California for TRECs continues to be strong in 2011 and 2012, which overlaps the test period in this case. The projected demand continues to be strong beyond the test period as well.

Q. What conclusion do you draw based on this information?

A. I conclude that it would not be reasonable to assume that regulatory uncertainty in California will cause a fall-off in TREC sales to that state relative to 2010. Indeed Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric have recently issued, in May 2011, a Request for Offers for TRECs for the period of 2011 and beyond.

Q. Have there been other developments with implications for REC sales in the test period?

A. Yes. As indicated in RMP's Confidential Response to DPU 10.52, the Company has entered into a REC sales agreement with [redacted].

Q. Has RMP updated its forecast of REC sales for the test period?

A. Yes. As of the date of this testimony, RMP has updated its REC revenue projections twice. The first update occurred on March 17, 2011, when the Company increased its projection to $76.3 million.[5] Then, on March 28, RMP further updated its test period forecast for REC sales to $86.1 million.[6]

Q. What is your assessment of RMP's updated forecast?

A. In my opinion, the most recent updated forecast provided by RMP in the data response referenced still understates the likely value of REC revenues that will be received in the test period, just as its prior forecasts in this docket did. For ratemaking purposes, the REC revenue credit should be set substantially higher than any of RMP's projections.

Q. Please explain the basis of your assessment.

A. There are two main components of RMP's REC sales projection for the test period: (1) known transactions and (2) projected incremental transactions. As of March 28, 2011, the known REC transactions for the test period have a value of [redacted] million. RMP's projected incremental transactions amount to only [redacted] million.

RMP calculates the value of the projected incremental transactions by assuming that it can sell the RECs associated with 75 percent of the wind output that remains after the RECs needed to meet RMP's Oregon and California RPS's are subtracted from total wind output. Of this 75 percent target, a portion is used for the known transactions. RMP then values the remaining RECs (of the 75

[5] Source: Confidential RMP Response to DPU 10.52. It is my understanding that the price and quantity of these projected sales are confidential, but that projected total revenue is not.

percent target) at a price of only $7.00 per REC to estimate the value of the projected incremental transactions. RMP also projects approximately [redacted] million for sales of vintage RECs.

RMP's price estimate of $7.00/REC for its projected incremental transactions is [redacted] than the average transaction price for known wind transactions in the test period of [redacted]/REC and dramatically lower than RMP's average REC sale price in 2010 or 2009 of [redacted]/REC and [redacted]/REC, respectively. RMP's assumed pricing of incremental sales at a [redacted] of average actual prices gives rise to the Company's unreasonably low estimate of test period REC revenues.

Q. How accurate has RMP's approach to projecting REC revenues in general rate cases been in recent years?

A. Not very accurate. RMP has significantly under-projected the REC revenues in its recent rate cases in Utah and Wyoming. In the 2009 Utah general rate case, RMP initially projected REC sales revenues of $7.4 million for the test period ending June 2010. This estimate was subsequently revised to $18.6 million in RMP's rebuttal filing. Actual REC revenues for the test period turned out to be $98.5 million. While certain extraordinary conditions occurred during the pendency of that rate case, which I will address later in my testimony, RMP also significantly underestimated REC revenues for Calendar Year 2010 in a subsequent Wyoming docket.

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6 Source: Confidential RMP Response to DPU 10.52-2, 1st Supplemental.

Q. How much did RMP's projections in Wyoming underestimate actual REC sales for Calendar Year 2010?

A. In its October 2, 2009 filing in the 2009 Wyoming general rate case, Docket 20000-352-ER-09, RMP projected REC revenues of $36.4 million for the test period ending December 2010. Based on discovery produced during the course of the case, parties to the case stipulated to a sales projection of $84.4 million, with a one-time true-up. Actual REC revenues in the test period turned out to be $101.1 million.

Q. Did you offer a REC sales projection in that Wyoming case?

A. Yes.

Q. What was it?

A. I estimated REC sales of $95.2 million – which was more accurate than RMP's projection, but which still understated actual results.

Q. Does the use of a test period 17¼ months beyond the filing date have implications for the REC revenue projection in this case?

A. Yes. Because RMP consistently uses a sales price for projected incremental sales that is dramatically lower than the price of known transactions, the Company's REC sales forecast turns out to be very sensitive to the length of the forecast horizon. The further out the test period extends from the forecast, the fewer the known transactions, and the more likely the Company's approach will lead to an understatement of REC revenues. This concern was one of the reasons I proposed a closer-in-time test period, and this is one of RMP's projections that should be carefully scrutinized, as suggested in the Commission's test period order.

Q. What projected level of REC sales revenue should be used in setting rates in this case?

A. I recommend using a REC sales revenue projection of $110.5 million for the test period.

Q. How did you derive this value?

A. I start with the most recent information provided by RMP regarding the value of known transactions. I then estimate that 50 percent of the still-available wind RECs will be sold at a price that is 90 percent of the average price of known transactions in the test period.

Q. Why do you believe it is reasonable to estimate that wind RECs will be sold at a price that is 90 percent of the average price of known transactions in the test period?

A. The best proxy price for incremental REC sales would be to use the average price of known transactions in the test period, which is [redacted]/REC. However, I am only proposing to use 90 percent of this price ([redacted]/REC) to be conservative. I note that this price is comparable to the average REC sales price registered by RMP in 2010 of [redacted]/REC and is consistent with RMP's projection of wind REC price forecast provided in discovery of [redacted]/REC for

2011 and [redacted]/REC for 2012.[7] In contrast, RMP's assumption that incremental REC sales will occur at a price of only $7.00/MWH is simply not credible in light of the price of known transactions, as well as RMP's own wind REC price forecast. Use of the $7.00/MWH price to forecast the value of incremental REC sales is not reasonable as it is likely to significantly understate the value of the REC revenue credit to Utah customers, resulting in rates that are artificially high.

Q. Why do you believe it is reasonable to estimate that 50 percent of still-available wind RECs will be sold?

A. This conservative projection is informed by several factors. For example, in 2010, RMP's actual REC sales were [redacted] percent of the RECs predicted by RMP to be available for that year. My estimate is equivalent to RMP selling [redacted] percent of the RECs predicted by the Company to be available for the test period – less than last year's actual performance on a percentage basis.

Further, as shown in Confidential UAE Exhibit RR 1.4, page 6, my REC sales volume estimate for the test period represents projected growth over 2010 volumes of [redacted] percent, whereas RMP's estimate of RECs available for sale is projected to grow by [redacted] percent. Meanwhile, as shown in Table KCH-2, above, the important California TREC market is projected to grow by 25.7 percent between 2010 and 2011, with 2012 TREC purchases holding fairly steady relative to 2011.

Q. How does your REC sales volume estimate compare with that of RMP?

[7] RMP Response to UAE 5.4, Confidential Attachment UAE 5.4.

A. The two estimates are very close. As shown in Confidential UAE Exhibit RR 1.4, page 6, my estimate exceeds RMP's by less than 0.2 percent.

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

A. My recommended adjustment is presented in Confidential UAE Exhibit RR 1.4. This adjustment reduces Utah's revenue requirement by approximately **$33,029,029**.

ANCILLARY REVENUE

Q. Please explain your adjustment to ancillary revenue.

A. In its filed case, RMP removed approximately $2.5 million in ancillary revenue from its total Company revenue requirement to reflect the termination of an ancillary services contract on December 31, 2011. Because the contract terminates midway through RMP's test period, the Company made an adjustment that removes 50 percent of the annual revenue derived from this contract.[8]

The contract in question is long-term in nature. RMP has stated in discovery that "the Company is in discussion over terms and conditions for a new contract but nothing is final at this time."[9] The counterparty is a public entity that has entered into an agreement to purchase from a third party the energy and environmental attributes of a wind generating facility. The counterparty has stated in public documents that it is "critical" that it acquire, prior to 2012,

[8] Exhibit RMP__(SRM-3), p. 3.6.'
[9] RMP Response to UAE 8.1(d).

transmission and/or integration and exchange services from RMP for the last ten years of its wind purchase agreement. A copy of this public document is included in Confidential UAE Exhibit RR 1.5.[10] Given the apparent dependence of the counterparty on RMP for provision of some type of service going forward, RMP's assumption that zero revenue will be recovered from this ancillary services agreement after December 31, 2011 seems highly implausible. Although the revenue may wind up increasing or decreasing, the best assumption for ratemaking purposes is to retain the revenues in the revenue requirement at the status quo. Consequently, I have made an adjustment that reverses RMP's adjustment and restores the full annual revenue as a credit in rates.

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

A. This adjustment is presented in UAE Exhibit RR 1.6. This adjustment reduces Utah's revenue requirement by approximately **$1,063,097**.

IMPRUDENCE OF CERTAIN ENVIRONMENTAL UPGRADE EXPENDITURES

Q. What recommendation are you making with respect to RMP's environmental expenditures?

A. I am recommending that a portion of RMP's environmental upgrade expenditures be determined to be imprudent because they are not cost effective, as

[10] Although this document is public and came into my possession over the internet, RMP has treated the identity of the counterparty and the details surrounding this contract as confidential. Consequently, I am presenting it in a confidential exhibit.

explained by UAE witness Howard Gebhart. The imprudent expenditures pertain to the Company's share of costs for scrubbers/SO_2 reduction projects at the following plants:

Huntington Unit No. 1
Total Disallowed Expenditure: $52.5 million
RMP share: 100%
In service dates: Nov. 2010, Dec. 2010, Mar. 2011

Hunter Unit No. 1
Total Disallowed Expenditure: $19.8 million
RMP Share: 93.75%
In service date: Mar. 2012

Hunter Unit No. 2
Total Disallowed Expenditure: $70.2 million
RMP Share: 60.31%
In service dates: May 2011, Mar. 2012

Dave Johnston Unit No. 3
Total Disallowed Expenditure: $78 million[11]
RMP Share: 100% In service date: May 2010

Q. Why should Mr. Gebhart's findings that these investments are not cost effective be the grounds for a finding of imprudence and disallowance of cost recovery by this Commission?

A. Only those costs that are reasonably incurred to provide service to customers should be recovered in rates. Mr. Gebhart has demonstrated that these

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In a very recent data response, RMP suggested that this cost figure is too high, despite the fact that it is the same number reported by RMP to the Wyoming Department of Environmental Quality (WDEQ) and relied on by the WDEQ in preparing its BART analysis. UAE has not yet had adequate time to explore RMP's recent claims, but will do so prior to the next round of testimony. I note that, even at the lower incremental cost now claimed by RMP, the upgrade option selected by RMP is not cost-effective according to an analysis provided by RMP's consultants. If RMP's revised numbers are accurate, it will reduce my proposed disallowance for this facility, but will not eliminate it.

expenditures were voluntary, in that RMP was <u>not</u> required by existing or reasonably anticipated environmental regulatory requirements or authorities to make these investments. Nor can the investments reasonably be construed to be cost effective in contributing to meaningful environmental improvements. Customers should not be expected to pay for utility investments that are neither necessary nor cost effective.

Q. Is your recommendation for disallowance indicative of an unwillingness of UAE members to pay for environmental improvement costs?

A. No, not at all. Mr. Gebhart carefully considered each environmental upgrade investment that is proposed in this case for inclusion in rate base and evaluated each on its merit. In many instances, Mr. Gebhart identified investments that were not required by regulators, but nonetheless proved to be cost effective in terms of achieving environmental improvement. UAE is not recommending disallowance of such costs. Rather, UAE's recommendation for disallowance is limited to the most egregious examples of unnecessary expenditures.

Q. What is the revenue requirement impact of UAE's recommendation for disallowance?

A. The revenue requirement impact of the disallowance is presented in UAE Exhibit RR 1.7. The Utah revenue requirement reduction, by facility, is as follows:

Hunter 1 Scrubber Upgrade	$294,824
Hunter 2 Scrubber Upgrade	$1,820,735
Huntington 1 Scrubber Upgrade	$2,513,687
Dave Johnston 3 SO_2 Project	$3,708,625
TOTAL	**$8,337,870**

Q. You include a disallowance for Dave Johnston Unit #3. Are the impacts of the SO_2 upgrade costs for that unit being included in Utah rates for the first time in this docket?

A: No, they were first brought into Utah rates as a result of a stipulation in the first Major Plant Additions case ("MPA I") on July 1, 2010.

Q: If you did not challenge the inclusion of these costs in rates at that time, why are you challenging them now?

A: The MPA statute is designed to permit RMP to recover the annual revenue requirement impact of a major plant addition as soon as it goes into service. The MPA I stipulation was intended to resolve this immediate revenue requirement impact of the facilities addressed in that case, which it did. My testimony here does not address the annual revenue requirement allowed into rates under the MPA I Stipulation. That stipulation has no further relevance when the facilities are rolled into base rates in this general rate case. This is the first time that the prudence of the Dave Johnston Unit #3 scrubber upgrade facilities has been challenged before this Commission.

WAGE AND BENEFITS EXPENSE

Q. What is RMP proposing for its wage and benefit expense?

A. RMP is proposing an increase of $34.9 million (total Company), or 7.2%, over the wage and benefit expense for the historical period ending June 2010. A summary of the Company's wage and benefit expense history since 2007 is presented in UAE Exhibit RR 1.8, page 3. This exhibit also presents RMP's proposed wage and benefit expense for the test period ending June 2012.

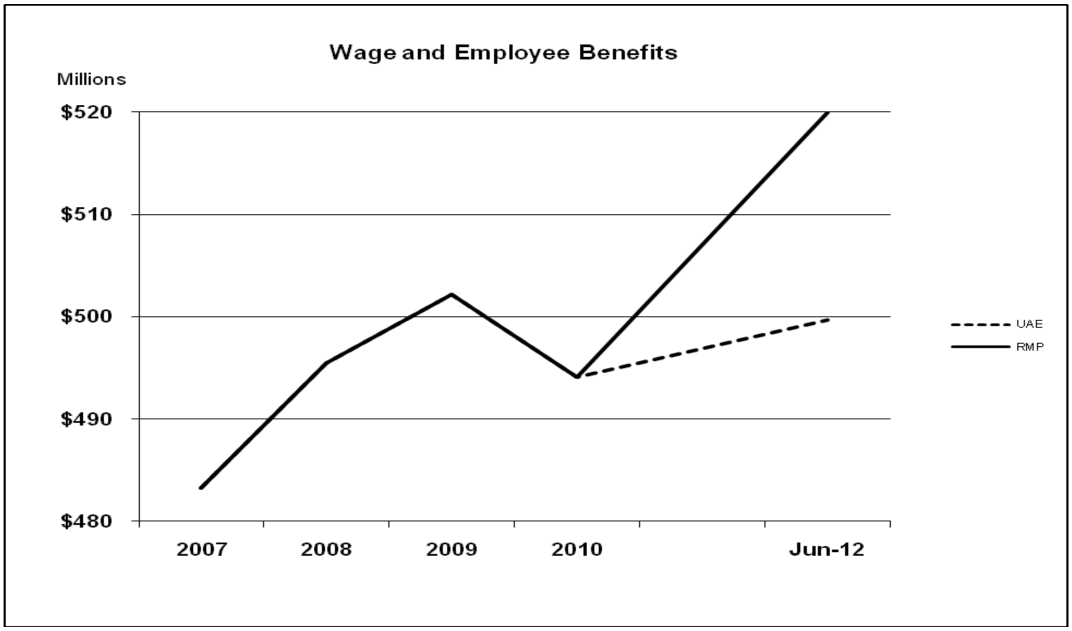
Q. What are your observations concerning RMP's proposed wage and benefit expense?

A. RMP's actual annual wage and benefit expense (which excludes capitalized labor) for the period 2007 through 2010 ranged between $483 million and $502 million. The maximum expense occurred in 2009. In 2010, wage and benefit expense fell to $494 million, and for the period ending June 2010 (filed in this case), it was $485 million.

The wage and benefit expense that RMP is proposing to be included in rates is materially greater than the Company's experience over the past four years: it is 5.2% greater than actual 2010 expense and, as noted above, 7.2% greater than the actual expense for the 12 months ending June 2010. The trend line for the four calendar years plus RMP's proposal for 2011 is shown in Figure KCH-1 below.

Figure KCH-1

RMP Wage and Employee Benefits
2007-2012



Q. **What are the main drivers behind RMP's proposed increase in wages and benefits?**

A. As shown in UAE Exhibit RR 1.8, page 3, two significant components of the increase are pension expense (an increase of $10.3 million relative to 2010) and medical benefits ($5.8 million increase). RMP is also proposing an increase of $7.1 million in its annual incentive program, while regular wage expense ("regular ordinary time") is proposed to increase by $16.4 million.

Q. **Has any other utility commission recently ruled on RMP's proposed wage and benefit expense in a general rate case?**

A. Yes. On February 28, 2011, the Idaho Public Utilities Commission issued its Order in RMP's general rate proceeding, Case No. PAC-E-10-07. On the subject of wages, the Idaho Commission Staff cited to the difficult economic conditions prevalent in the Company's Idaho service territory and proposed that all wage increases awarded by the Company to its employees during 2009 and 2010 be disallowed in rates. The Idaho Commission concurred, ruling that:

> The Commission finds that in challenging economic times the local economy in the Company's service area is a greater indicator as to the appropriateness of a wage increase than market data and industry averages. We find no demonstration by the Company that the union and non-union wage increases were required for the Company to be a competitive employer able to retain or attract employees. We find no evidence that without the union and non-union wage increase the service provided by the Company would be degraded and safety compromised. We find that as a certificated provider of service RMP has elected to be a member of the communities it serves. We find Staff's proposed wage adjustment to be reasonable. The Company may choose to implement its wage increases, but we will not allow recovery of that expense from its Idaho customers. [Order 32196 at 18-19]

Q. What is your recommendation for addressing RMP's proposed increase in wage and benefit expense?

A. I agree with the Idaho Commission that it is important to be sensitive to the economic conditions faced by customers when determining the amount of increased wage and benefit expense that will be passed on to those customers in rates. Utilities should not be exempt from the belt-tightening that its customers must endure during challenging economic circumstances. I find it especially troubling that RMP is proposing to recover an additional 26.7% ($7.1 million) for its incentive pay plan at a time when the Company is proposing to increase Utah rates by a very substantial 13.7 percent.[12]

As shown in UAE Exhibit RR 1.8, RMP's *actual* wage and benefit expense has been relatively contained within the past four years: indeed the Company's wage and benefit expense was only 2.24 percent higher in 2010 than it was in 2007. It is only when we come to the projected test period used for setting rates that a projected large year-over-year jump occurs.

From a regulatory standpoint, it is not necessary to adjust each line item of the Company's wage and benefit expense, particularly when using a future test period. My recommendation is that the Commission set an overall level of wage and benefit expense that is acceptable in rates, recognizing that it is RMP's choice to pursue a test period that extends significantly into the future and the Commission must use its best judgment to ascertain the level of projected wage and benefit expense that ratepayers should bear. For the purposes of this case, I recommend that the Commission approve an overall wage and benefit expense equal to the Company's Calendar Year 2010 actual expense plus 0.75 percent on an annualized basis, which is an increase of 1.13 percent for the test period relative to 2010. This approach results in a wage and benefit expense for ratemaking purposes of $499.7 million (total Company).

Q. Why do you propose allowing a 0.75 percent annualized increase over the level experienced in the year ending December 2010?

[12] When the termination of Schedules 97 and 98 is taken into account, the increase is closer to 14.5 percent.

A. Such an increase is consistent with the Company's experience over the past several years. Even though 2010 actual wage and benefit expense declined relative to 2009, on average, the year-over-year increase in RMP's wage and benefit expenses has been running about 0.75 percent since 2007. I recommend approval of wage and benefit expense in rates that is consistent with this three-year trend in RMP's wage and benefits costs.

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 **$8,430,269**. The impact of this adjustment on net operating income is shown in UAE Exhibit RR 1.8.

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 2010 through June 2012.

To apply this cost escalator, RMP starts with its actual non-labor O&M expense for the base period, July 2009 to June 2010. 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. 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 published Minutes of the Federal Reserve Open Market Committee since the beginning of the year. The Minutes of the April 26-27, 2011 meeting indicate that the Fed's central tendency forecast for core inflation is in the range of 1.3% to 1.6% for 2011, and 1.3% to 1.8% for 2012.

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 1.9.

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

A. This adjustment reduces Utah revenue requirement by **$7,466,328**.

Q. Does removing the cost escalation from non-labor O&M prevent RMP from recovering increased O&M costs associated with new facilities?

A. No. Incremental O&M cost for new facilities is presented in a separate adjustment by RMP and is not affected by this adjustment.

Q. Does removing the cost escalation from non-labor O&M eliminate the effects of all input-related price changes from the general rate case?

A. No. As I discussed above, I am recommending a modest increase in rates to account for higher wage and benefit costs, which includes labor input prices. Even more significantly, the revenue requirement for net power costs incorporates projected prices for inputs related to power production.

GAS SWAPS

Q. What is the impact of gas swaps on RMP's revenue requirement in this case?

A. Gas swaps are a component of RMP's net power cost. The gas swap cost represents the difference between the cost of RMP's gas hedges and the projected market cost of the natural gas in the test period. If the cost of the hedges is less than the projected market cost, then gas swaps provide a credit against net power cost. Conversely, if the cost of the hedges is greater than the projected market price, then gas swaps represent a cost.

In RMP's filed case, gas swaps represent a projected system cost of $160.7 million.

Q. Is this swap cost unusual?

A. The fact that the gas swap is a cost and not a credit is not unusual: RMP's gas hedges have consistently added materially to net power cost for several rate cases. However, the magnitude of the swap cost in this case is worth noting. Utah's share of the $160.7 million gas swap cost is about $68.4 million, representing nearly 30 percent of the Company's proposed increase in this case.

Q. Has the Commission commented recently on gas swaps?

A. Yes. In its March 3, 2011 Order issued in the EBA Docket, the Commission stated that swap transactions should be excluded from the calculation of both base and actual net power cost. [Order at 72] However, in its Order on Petition for Clarification and Reconsideration or Rehearing, issued May 9, 2011, the Commission agreed to examine this question further.

In its March 3, 2011 EBA Order, the Commission also concluded that swap transactions "must be reviewed and approved in each general rate case, which is an appropriate proceeding for determining the prudence of Company decisions." [Order at 72]

Q. In light of this latter directive, have you prepared any adjustments to RMP's gas swap expenses?

A. Yes. Based on the analysis presented in the direct testimony of UAE Jeff J. Fishman, I am recommending that RMP's gas swaps associated with a hedged position greater than 75 percent of the Company's projected monthly gas requirement in the test period be excluded from cost recovery.

Q. What is the basis of your recommendation?

A. A hedged fuel supply <u>should</u> be part of a utility's portfolio, and to the extent that reasonably-transacted hedges cause an increase in net power costs, then it is reasonable for customers to bear this cost. The issue here is one of extent. RMP's hedging practices have been the subject of extensive inquiry by this Commission in recent years and it is now well understood that the aggressiveness (i.e., extensiveness) of the Company's gas hedges cause RMP to be an outlier in this respect relative to other utilities.

Based on Mr. Fishman's analysis, I have concluded that a reasonable *upper boundary* for utility hedged gas supply is 75 percent. In contrast, RMP actually forecasts three instances in which its gas hedge position for a given test period month exceeds [redacted]. After observing RMP's hedging practices over several proceedings, I have concluded that the Company appears to be motivated more by a corporate preference to [redacted] its future gas supply costs than to create a strategically diversified portfolio of gas supply pricing. While it is reasonable for customers to bear the hedging costs of achieving a diversified fuel supply portfolio, it is not reasonable for customers to bear the incremental cost of what appears to be an idiosyncratic corporate predilection. Consequently, I am recommending that RMP's gas swaps associated with a hedged position greater than 75 percent of the Company's projected monthly gas requirement in the test period be excluded from cost recovery.

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

A. This adjustment is shown in Confidential UAE Exhibit RR 1.10. This adjustment reduces RMP's Utah revenue requirement by approximately **$12,519,631**.

SALE OF ASSETS

Q. Has RMP proposed to sell any assets, the sale of which is not included in the Company's revenue requirement in this case?

A. Yes. I am aware of two proposed sales. On April 20, 2011, RMP filed an application with the Wyoming Public Service Commission for authority to sell its interest in the Snake Creek Hydroelectric Generating Plant in Utah. The approximate sales price reported in the application is $1.2 million. If the sale goes forward, then the plant should be removed from rate base and any gain on the sale should be credited to customers in this rate case. The gain on the sale would be the difference between the sales price and the net book value of the facility. The application for the sale filed by RMP in Wyoming does not indicate how much of the sales price represents a gain, but that is the subject of a pending data response.

In addition, in Wyoming PSC Docket No. 20000-382-EA-10, RMP received authority to sell its interest in the Windstar Substation and Dave Johnston Substations to Black Hills Power Corporation. As this sale is either imminent or completed, this plant should be removed from rate base and any gain on the sale should be credited to customers in this rate case. The details on this sale are also the subject of a pending data response. I intend to supplement my testimony with the amount of the appropriate adjustments following receipt of this information.

RENEWABLE ENERGY CREDITS – RECOGNITION OF DEFERRED REVENUES IN RATES

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I address the issue of RECs that have been deferred from prior periods. I recommend establishment of a credit to customers in this docket that would be reflected in rates at the start of the rate effective period in this case and would be returned to customers over two years using two consecutive one-year recovery periods, as described below.

Q. Please identify the deferral time periods to which your discussion pertains.

A. My discussion applies to two time periods:

(1) February 22, 2010 through December 31, 2010. This period starts on the date of UAE's application filed in Docket No. 10-035-14 for a deferred

accounting order applicable to incremental REC revenues. It runs until the initiation of Schedule 98, which was approved in the MPA II Docket. Schedule 98 provides a sur-credit to Utah customers of approximately $3 million per month for 2011 REC revenues. The appropriate revenue credit to customers for this period (2/22/10-12/31/10) is Utah's share of the difference between actual REC revenues booked during the period and the REC revenues reflected in base rates approved by the Commission in its decision in Docket No. 09-035-23, plus interest. I recommend that this balance be credited back to customers over the one-year period September 21, 2011 through September 20, 2012.

(2) January 1, 2011 through September 20, 2011. This period runs from the initiation of Schedule 98 through the start of the rate effective period in this case. The appropriate revenue credit (or debit) to customers for this period is Utah's share of the difference between actual REC revenues booked during this period and the combined REC revenues reflected during this period in base rates, Schedule 98, and Schedule 40, the latter of which incorporates incremental revenue associated with the Dunlap I wind facility approved as part of the MPA II Docket, plus interest. I recommend that this balance be credited back to customers over the one-year period September 21, 2012 through September 20, 2013. Thus, the crediting back to customers for this period would immediately follow upon the conclusion of the crediting period for the deferrals recorded from February 22, 2010 through December 31, 2010 deferrals.

Q. Have you reviewed the application for deferred accounting filed by UIEC in Docket No. 11-035-46?

A. Yes, I have.

Q. How does the time period implicated by that application relate to your testimony in this proceeding?

A. UIEC's application is addressed to the time period prior to February 22, 2010. The Commission has set a separate schedule for UIEC's application and it is UAE's assumption that the issue of incremental REC revenue recovery for the time period prior to February 22, 2010 will be determined in connection with or following resolution of UIEC's application in that docket. I note, however, that many of the facts and circumstances described below are equally applicable to periods covered by the UIEC Application.

Q. What is the basis of your recommendation that a credit to customers for REC deferrals for the period beginning February 22, 2010 should be reflected in rates in this case?

A. My recommendation in this proceeding is an extension of prior recommendations I have presented to the Commission in both the EBA Docket and the MPA II Docket. These recommendations have their origins in the contentions made by UAE in its application for a deferred accounting order for incremental REC revenue filed in Docket 10-035-14, as well as in Docket No. 11-035-46.

UAE's application in Docket No. 10-035-14, dated February 22, 2010, was filed four days following the Commission's general rate case order issued in Docket No. 09-035-23, in which the Commission approved a revenue requirement increase for RMP of $32.4 million. As explained in that application, the market value available to RMP in selling RECs had recently increased in a manner that was dramatic, unprecedented, unforeseeable, and extraordinary. Moreover, RMP did not incorporate into its rate case projections or disclose to the Commission in the recently-concluded general rate case the extraordinary increase in the value of RECs that it was receiving and projecting. As a result, RMP received significant incremental revenue from selling RECs over and above the value reflected in Utah rates. Based on these facts and the legal principles discussed in UAE's application, UAE argued that a deferred accounting order should be issued to require RMP to defer for future ratemaking treatment all incremental REC revenue from the date of UAE's application to the effective date of new rates in a future RMP proceeding.

Pursuant to a stipulation entered among parties to Docket No. 10-035-14, the Commission approved UAE's deferred accounting request for incremental REC revenues in its order issued July 14, 2010. However, the appropriate ratemaking treatment of the deferred REC revenue was left for future determination by the Commission.

Q. Do you have a recommendation regarding the appropriate ratemaking treatment of the REC revenues deferred as a result of UAE's application?

A. Yes. One hundred percent of the deferred REC revenues should be credited to customers. A sur-credit should be established at the start of the rate effective period in this case that will refund to customers over a period of two years the deferred balance (including interest) accrued through the start of the rate effective period (presumed to be September 21, 2011), as described in my testimony. These steps are the most reasonable actions that can be taken in response to the extraordinary and unforeseeable orders-of-magnitude increase in REC revenues that RMP experienced at the time the last general rate case, Docket No. 09-035-23, was being concluded.

Q. Please explain why the increase in REC revenue realized by RMP over and above what is recognized in Utah rates was unforeseeable and extraordinary.

A. Towards the latter part of 2009, REC values soared to unprecedented levels. As I will discuss in more detail below, in a matter of weeks, between the time of the Company's rebuttal filing and the issuance of a final order in Docket No. 09-035-23, RMP's own projections for annual REC revenues increased by more than fourfold. This orders-of-magnitude of change is clearly extraordinary by any reasonable standard. Moreover, the scale of dollars involved is substantial. RMP's booked REC revenues for the test period used in the prior rate case turned out to be $98.5 million[13] – more than five times the level included in

[13] There appears to be some discrepancy between the REC revenues reported in RMP's filing of its base year REC revenues in this docket ($98.5 million) and the REC revenues reported by RMP for the same period in discovery of $97.3 million. This apparent discrepancy is the subject of a pending data response.

rates. Proper recognition of these revenues in Utah rates would have made the rate increase adopted by the Commission on February 18, 2010 entirely unnecessary. The scale of the dollars involved reinforces the extraordinary nature of the change in REC revenue received by RMP.

Further, as also discussed in more detail below, given the timing of the information released by the Company, the extraordinary change in revenue was not foreseeable to parties who were not directly involved in the negotiations that led to the tremendous run-up in the price of the RECs that RMP sold to others.

Q. Please describe the timing and magnitude of the changes in projected REC revenues issued by RMP.

A. In the Company's filing in Docket No. 09-035-23, submitted in June 2009, RMP projected $7.4 million in REC revenues for the test period ending June 2010. RMP's rebuttal testimony in that same docket, filed November 12, 2009, stated that for purposes of the rate case, $18.6 million represented a reasonable estimate of its system-wide REC revenues for that test period.[14] The Commission's Report and Order in that docket, dated February 18, 2010, utilized that value in setting Utah rates.

A timeline of RMP REC revenue projections based on RMP confidential data responses is presented in Confidential UAE Exhibit RR 1.11. By early October 2009, RMP was already internally projecting REC sales for Calendar Year 2009 in excess of $40 million.[15] Indeed, REC revenues for October 2009

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[14] Rebuttal testimony of Steven R. McDougal, pp. 5-6.
[15] See Confidential UAE Exhibit RR 1.11.

alone spiked to [redacted] million.[16] Actual monthly REC booked revenue from January 2009 through December 2010 is presented in Confidential UAE Exhibit RR 1.12, page 3. As shown in that exhibit, the Company's booked REC revenue in the fourth quarter of 2009 alone exceeded [redacted] million – which is more than [redacted] the amount of REC revenues the Company had indicated on November 12 was reasonable for the *entire test period*. This was followed by another [redacted] million of REC revenues booked for January 2010. Thus, in the four months preceding the Commission's February 18 Order in the rate case, RMP booked over [redacted] million in REC revenues, while rates set in that order assumed just $18.6 million for the entire test period.

By January 2010, just two months after filing its rebuttal testimony in Utah, and prior to the issuance of the final order in Docket No. 09-035-23, RMP projected REC sales of $84.4 million for Calendar Year 2010 – more than four times the value of the RECs used in setting rates in Utah one month later.[17]

In a matter of weeks, RMP's own projections for REC sales had grown by orders of magnitude prior to the conclusion of the Utah rate case. Yet this information was not disclosed by RMP to the parties in the Utah rate case. Nor was it disclosed, to my knowledge, to the Utah Commission.

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[16] Source: RMP Response to DPU 7.62(c). Also shown in Confidential UAE Exhibit RR 1.12, page 3.
[17] The $84.4 million value appeared in a confidential data response provided to parties in a general rate case in Wyoming, and thus was not publicly disseminated until March 18, 2011 when RMP stipulated in Wyoming to system-wide REC sales of $84.4 million for Calendar Year 2010 (with a provision for a true-up).

The hearings in the revenue requirement phase of the rate case took place from December 2, 2009 to December 8, 2009. Given the speed at which REC values changed, and the timing of the information made available to the parties in the proceeding, the extraordinary and rapid increase in projected REC revenues was not reasonably foreseeable to the parties in the Utah case within the framework of the procedural schedule – at least not for those parties without firsthand knowledge of the transactions that were unfolding.

With this surge in REC revenue, it seems RMP was in a position prior to the issuance of the Commission's Order to inform the parties and Commission that the Company's actual and projected REC revenues were growing in a dramatic and unprecedented fashion, with serious implications for the pending rate case decision. Yet the Company apparently chose not to disclose this information in the Utah docket. In any case, whether or not RMP should have disclosed these facts at the time, they clearly represent events that were extraordinary in relation to past REC values and sales and that were unforeseeable to the Commission or the other parties to the 2009 general rate case.

Q. What amount of REC sales revenue did RMP book between October 2009 and February 22, 2010, the date of UAE's application for deferred accounting?

A. I estimate that RMP booked approximately [redacted] million in REC revenues during that time. This level of bookings was clearly extraordinary and not foreseeable when then-current rates were set. As noted above, because these revenues were booked prior to February 22, 2010, UAE will address the issue of the potential crediting to customers of the incremental portion of these revenues in or after resolution of Docket No. 11-035-46, as I indicated above.

Q. What amount of REC revenues was ultimately recorded by RMP for the test period used in the previous rate case?

A. According to the Company's base year filing in this case, the REC revenues actually recorded by the Company during the July 2009 to June 2010 test period totaled $98.5 million – approximately $80 million more than the REC revenues recognized in Utah rates for that test period. The difference in REC values actually received by RMP for the test period ending June 2010 and the REC values included in Utah rates translates into a <u>Utah</u> revenue requirement differential of approximately $46.2 million. Put another way, proper recognition of the surge in REC revenues in Utah rates would have wiped out the entire $32.4 million rate increase that was approved on February 18, 2010 in Docket No. 09-035-23 – and then some.

Q. By not disclosing the updated information on REC sales, was RMP simply maintaining consistency with a policy of not providing new revenue requirement adjustments in rebuttal testimony?

A. No. In that same docket RMP <u>did</u> provide a new revenue requirement adjustment in its rebuttal filing seeking a system net power cost increase of $7.9 million associated with a BPA peaking contract. This adjustment corrected an oversight in the Company's direct case – and was approved by the Commission.

Thus, RMP was clearly willing to bring new revenue requirement information to the Commission in its rebuttal case.

Q. Why should the deferred REC revenues be credited 100 percent to customers?

A. As stated above, REC sales are made using assets that are paid for entirely by customers; consequently, 100 percent of the revenues from REC sales are appropriately treated as a revenue credit against the revenue requirement recovered from customers in a rate case. This treatment is especially appropriate in light of the increasing cost burden borne by Utah customers to pay for RMP's aggressive expansion of its fleet of wind resources used for making REC sales; over the past several Utah rate proceedings the Company has added over $1.8 billion in wind-related plant in service (total Company). Utah's allocated share of these recent additions to wind plant in service is approximately $800 million. In addition, the Company's claims for wind integration costs have increased dramatically over the years. RMP's proposed cost recovery for wind integration now exceeds [redacted] million per year.[18] Finally, the circumstances under which the deferral was created – deriving from a surge in REC revenues during the pendency of a general rate case which, if recognized, would have obviated the need for a rate increase at all – strongly weigh in favor of 100 percent crediting to customers as soon as practicable.

[18] Source: Confidential RMP Response to DPU 10.37.

Q. What is the amount of the REC deferral for the period February 22, 2010 through December 31, 2010?

A. I estimate that the REC deferral for this period is **$46,209,511**. This calculation is presented in Confidential UAE Exhibit RR 1.12. This calculation was performed by taking the difference between the REC revenues booked each month as reported by RMP and the level of RECs in current rates. This calculation includes the accrual of interest at a rate of 5.98%, consistent with the rate approved by the Commission for this purpose in its Order issued July 14, 2010 in Docket Nos. 09-035-15 and 10-035-14.

Q. How did you measure the level of RECs in current rates?

A. I distributed Utah's share of REC revenues in rates across the months on the basis of monthly retail sales. For the month of February 2010, I assigned one-fourth of the retail load for the month to correspond to the February 22 starting date of the deferral period. I treated the REC revenues booked in that month in the same way.

Q. What is your recommended course of action with respect to the deferral period from January 1, 2011 through September 20, 2011?

A. This period has yet to run its course. As stated above, the appropriate revenue credit (or debit) to customers for this period is Utah's share of the difference between actual REC revenues booked during this period and the REC revenues reflected during this period in base rates, Schedule 98, and Schedule 40, the latter of which incorporates incremental revenue associated with the Dunlap I wind facility approved as part of the MPA II Docket, plus interest. I recommend that this balance be credited (or charged) back to customers over the one-year period September 21, 2012 through September 20, 2013.

Q. Does this conclude your direct testimony?

A. Yes, it does.