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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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge	**Docket No. 07-035-93**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT]

The UAE Intervention Group (UAE) and Wal-Mart Stores, Inc. ("Wal-Mart") hereby submit the Prefiled Direct Testimony of Kevin C. Higgins on revenue requirement issues.

DATED this 7th day of April, 2008.

/s/_______________________________
Gary A. Dodge,
Attorneys for UAE

Holly Rachel Smith,
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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 7th day of April, 2008, on the following:

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BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Direct Testimony of Kevin C. Higgins

on behalf of

UAE and Wal-Mart

[Revenue Requirement]

April 7, 2008

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 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 jointly sponsored by the Utah Association of Energy Users Intervention Group (UAE) and Wal-Mart Stores, Inc. Wal-Mart Stores, Inc. is a member of UAE that has intervened separately in this proceeding.

Q. Are you the same Kevin C. Higgins who previously filed testimony on behalf of UAE in the Test Year phase of this proceeding?

A. Yes, I am. A detailed description of my qualifications is contained in Attachment A, attached to my Test Year direct testimony.

Overview and Conclusions

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

A. My testimony addresses several revenue requirement issues in RMP's general rate case filing, and recommends adjustments to the Company's proposed revenue requirement in support of a just and reasonable outcome. My recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What are your primary conclusions and recommendations?

A. I am recommending the following adjustments to RMP's Utah revenue requirement:

(1) Net power cost should be re-calculated with the following changes:

(a) A minimum operating level of 115 MW for Currant Creek should be utilized, consistent with RMP's representation of the facility's operational flexibility at the time of Currant Creek's certification proceeding;

(b) Removal of the Nebo Heat Rate Option contract, as this contract appears to have expired;

(c) Removal of the Constellation 257677 and 257678 call option contracts in months in which the GRID model's dispatch of these contracts results in higher net power costs.

I estimate that the combined effect of these adjustments to net power cost is to reduce RMP's Utah revenue requirement by $2,602,444. (This adjustment does not include the impact of the re-negotiated power sales agreement between RMP and Sunnyside Cogeneration Associates, which is discussed separately.)

(2) Labor expense should be adjusted to produce a correct Calendar Year 2008 representation of wage increases. This adjustment results in a reduction in the Utah revenue requirement of $243,098.

(3) O&M expenses for the Glenrock and Seven Mile Hill wind energy generation facilities should be removed. These facilities are not scheduled to become operational until the last day of the test period, December 31, 2008. This adjustment reduces Utah revenue requirement by $537,432.

(4) O&M expense for the Marengo wind energy generation facilities should be reduced to reflect the fact that the Marengo Expansion will only be operational for 6 months in the Calendar Year 2008 test period, compared to 11 months in RMP's originally-proposed test period ending June 2009. This adjustment reduces Utah revenue requirement by $263,418.

(5) Lakeside O&M expense should be reduced such that it is no greater than what was projected for the test period ending June 2009. This adjustment reduces Utah revenue requirement by $261,500.

(6) The recent approval by the Utah Commission of RMP's amended contract with Sunnyside Cogeneration Associates should be reflected in rates. This adjustment reduces Utah revenue requirement by approximately $1.57 million, subject to final determination in net power costs.

(7) The amortization period for sales of SO_2 allowances made after January 1, 2008 should be reduced to three years. In addition, the amortization schedules for the remaining unamortized balances as of December 31, 2007 for SO_2 sales made before January 1, 2008 should also be accelerated from a four-year to a three-year schedule. I estimate that this adjustment reduces Utah revenue requirement by $2,923,167.

(8) RMP's Section 199 deduction (i.e., Domestic Production Activities deduction) should be adjusted to better reflect the Company's test period taxable income attributable to generation-related activities. I recommend using a Section 199 deduction of $12,076,887, based on RMP's estimate for the twelve months ending June 2008. This adjustment reduces Utah revenue requirement by $2,155,932.

The combined effect of these adjustments is to reduce Utah revenue requirement by $10,556,991.

<u>Net Power Cost</u>

Q. What issues do you address with respect to RMP's net power cost?

A. My analysis of net power cost focuses on the treatment of several resources in the Company's GRID model: the Currant Creek facility, the Nebo Heat Rate Option contract, and two other call option contracts.

Q. What is your assessment of the model's treatment of the Currant Creek facility?

A. The GRID model constrains the Currant Creek facility's operation such that the facility is not operated below 340 MW (with both units operating at 170 MW). This minimum run level is significantly higher than the minimum run level that RMP represented to the Commission in the Currant Creek certification proceeding in 2003. In that proceeding, RMP stressed Currant Creek's operational flexibility, with Company witness J. Rand Thurgood testifying that the Currant Creek facility could operate with an output as low as 115 MW.

Q. What are the implications of constraining the output of Currant Creek such that it cannot be run below 340 MW in the GRID model?

A. Such a constraint increases the net power cost charged to customers, because when lower-cost generation is available, and the Currant Creek facility is otherwise running in the model, the operation of the plant is not reduced below 340 MW. Instead, the plant stays in operation at this level in the model, displacing lower-cost resources (often coal-fired generation) resulting in higher net power costs for customers.

Q. Do you believe this constraint is reasonable?

A. No. This constraint in GRID unreasonably increases the cost of power charged to customers. In the Currant Creek certification proceeding, RMP persuaded the Commission that Currant Creek was the best option to meet the Company's resource needs, and was superior to proposals offered by competitive providers. In making its case, RMP emphasized the operational flexibility the Currant Creek facility would provide. For example, in describing the Currant Creek option Dr. Thurgood stated:

> Each gas turbine will be capable of independent dispatch and able to be dispatched from 50 percent to 100 percent of full load. Each gas turbine will be able to produce full power within 30 minutes of the initiation of a start and will be available for daily cycling duty. The units will be capable of operating up to 24 hours per day.
>
> During this simple cycle phase each turbine will be able to provide up to 70 MW of spinning reserve capability if the unit is dispatched at 50 percent of full load. The ramp rate of each simple cycle gas turbine will be approximately 13.5 MW per minute. After the conversion to combined cycle, each gas turbine can be dispatched separately and will have the capability to operate from 50 percent to 100 percent of full load. This capability, along with the duct firing capability, provides substantial operating flexibility. The 2x1 plant will be able to provide anywhere from 115 MW to 525 MW depending on the number of gas turbines operating, the load on each gas turbine, ambient conditions, and the level of duct firing."[1] [Emphasis added.]

The operational flexibility claimed by RMP for Currant Creek was emphasized by the Company when it justified the selection of Currant Creek over the proposals provided by other parties. For example, Dr. Thurgood testified:

> In developing Next Best Alternative (NBA) options as a benchmark for evaluating responses to the Request for Proposals (RFP) 2003A, the focus was on resource alternatives with operational flexibility, fuel efficiency, minimized environmental impact, and low overall evaluated cost. The proposed 2x1 configuration with its substantial flexibility from both the duct fired and non-duct fired capability, was

[1] Docket No. 03-035-29, Direct testimony of J. Rand Thurgood, pp. 5-6.

> selected as the most cost effective technology to help meet the Company's obligation to serve.[2] [Emphasis added.]

Q. What explanation has RMP offered with respect to the apparent change in operational flexibility for Currant Creek?

A. In its Response to CCS 2.24, RMP states that Currant Creek certification proceeding includes estimates of Currant Creek performance based on manufacturer specifications. RMP goes on to state:

> The Company's current unit ratings for Currant Creek include more than a year of operational experience at the facility. Further, for regulatory normalized ratemaking the Currant Creek plant is modeled in combined cycle mode with both gas turbines operating. This configuration is the most efficient configuration available, and all things being equal, is the configuration that the Company generally expects to operate the plant.

Q. In your opinion, is this explanation sufficient justification for calculating net power costs using a minimum operating level of 340 MW for Currant Creek rather than 115 MW as advertised by RMP in the Currant Creek certification hearing?

A. No. The flexibility of being able to operate Currant Creek at 115 MW was part of the decision criteria used to select this option over other alternatives that were proposed and was an integral part of the argument RMP used in attempting to persuade the Commission that the Company's selection of Currant Creek was the best decision. Customers should not now be expected to pay higher net power costs because the Company's representation of Currant Creek's operational flexibility was incorrect. Had

[2] Ibid., pp. 12-13.

one of the competitive alternatives to Currant Creek instead been selected, and if that independent supplier turned out to be unable to meet the operational flexibility to which it had committed in becoming the winning bidder, it seems highly unlikely that the incremental cost of the diminished operational flexibility would become a customer burden rather than a supplier burden.

To borrow RMP's terminology, for "regulatory normalized ratemaking", the GRID model should calculate net power costs using the same 115 MW minimum operating level for Currant Creek that RMP relied upon in selecting itself as the winning bidder to its RFP 2003A and which the Company represented in justifying its decision to the Commission. I believe this is a matter of basic fairness and accountability.

Q. Have you calculated the impact on net power costs of using a minimum operating level of 115 MW for Currant Creek?

A. Yes. On a stand alone basis, this adjustment reduces system-wide net power costs by $4.58 million. This calculation is shown in Confidential UAE-WM Exhibit RR 1.1, page 2. However, because I am also recommending other changes in net power costs, the impact must be calculated in combination with the other net power cost adjustments I am recommending.

Q. What change are you recommending with respect to the Nebo Heat Rate Option contract?

A. The documentation provided with the GRID model indicates that this contract expired in 2007.[3] Consequently, this contract and its costs should be removed from the net power cost calculation. The removal of this contract reduces net power costs.

Q. What other call option contracts do you address?

A. My analysis examines the impact on net power cost of two other call option contracts: Constellation 257677 and 257678. These are contracts in which RMP commits to a fixed premium (or capacity charge) that is paid whether or not the option is exercised. If the option is exercised, then RMP must also pay for the energy per the terms of the contract.

Q. What does your analysis show?

A. I tested the reasonableness of charging customers for the variable cost of these contracts by removing them from GRID's dispatch logic. For one of the contracts, the results show that its removal always reduces net power costs – even after paying the fixed premiums. The removal of the other contract reduces net power costs in two months and increases it for two months.

Q. What do you conclude from this result?

A. Customers should not be paying for the dispatch of contracts in GRID that cause net power costs to increase, as doing so artificially increases costs to customers. At a minimum, net power costs should be recalculated with these contracts not being

[3] Neither is it listed as a current contract in RMP Response to MDR 2.64.

dispatched in any month in which the variable cost of calling on these resources causes net power costs to increase.

Q. What is the impact on net power cost of removing the Nebo Heat Rate Option contract and of not dispatching these other two call options in months in which the variable cost of calling on these resources causes net power costs to increase?

A. On a stand alone basis, making this adjustment reduces system net power cost by $1.73 million. This calculation is shown in Confidential UAE-WM Exhibit RR 1.1, page 3. Making this adjustment in combination with the Currant Creek minimum operating level adjustment causes a reduction in net power cost of $6.28 million. This calculation is shown in Confidential UAE-WM Exhibit RR 1.1, page 4.

Q. How should the call option premiums be treated?

A. At the current prices utilized in the GRID model, these contracts are often “out of the money” for the months in which the contracts are applicable; thus, the Commission may wish to consider disallowing these premium costs for such months. However, it is conceivable that under a different set of market prices these contracts might have provided a benefit to customers in GRID. Therefore, I am limiting my recommended adjustment at this time to removal of the variable costs in months in which calling on these resources causes net power costs to increase.

Q. Please summarize your recommended adjustments to net power cost.

A. Net power costs should be reduced by assuming a minimum operating level of 115 MW for Currant Creek, by removing the Nebo Heat Rate Option contract, and by not dispatching two other call option contracts in months in which the variable cost of exercising these options causes net power costs to increase. The result of these adjustments reduces system net power costs by $6.28 million. I estimate that this adjustment reduces the Utah revenue requirement by $2,602,444. This adjustment is presented in Confidential UAE-WM Exhibit RR 1.1, page 1 (the first page of which is not confidential).

Q. Do these limited adjustments preclude other adjustments to net power costs?

A. No. These adjustments are the result of my examination of the GRID model's treatment of the resources I chose to examine. It does not preclude other adjustments to net power costs based on a more comprehensive examination. I note also that the adjustment I present here does not include the impact of the re-negotiated power sales agreement between RMP and Sunnyside Cogeneration Associates, which I discuss separately.

Labor Expense

Q. Please explain your adjustment to labor expense.

A. In re-filing its case using a Calendar Year 2008 test period, RMP incorrectly calculated pro-forma labor expense. The Company correctly used pro-forma wage increases for the July 2008 through December 2008 period, but used end of period (June 2008) annualized wages for the first half of the year rather than pro-forma wage increases.[4] This error overstates system labor costs for the calendar year by $568,633. Correcting this calculation results in a reduction in the Utah revenue requirement of $243,098, as shown in UAE-WM Exhibit RR 1.2.

<u>Glenrock and Seven Mile Hill O&M Expense</u>

Q. Please explain your adjustment to the Glenrock and Seven Mile Hill O&M expense.

A. Glenrock and Seven Mile Hill are wind facilities that are scheduled to become operational December 31, 2008. RMP has included O&M expense for these facilities for the period starting September 2008. These expenses should be removed, as the facilities will not be operational in that time period. This adjustment reduces Utah revenue requirement by $537,432, as shown in UAE-WM Exhibit RR 1.3.

<u>Marengo Expansion O&M Expense</u>

Q. Please explain your reason for proposing an adjustment for the Marengo Expansion O&M Expense.

[4] This can be seen by examining RMP Exhibit (SRM-1S), p. 4.10.4 - 4.10.5. For example, the January 08 pro-forma entry of $2.773 million for Group Code 3 (bottom of p. 4.10.4) is treated as $2.856 million in the Test Year (bottom of p. 4.10.5) even though the wage increase for this group does not occur until February 2008.

A. As described in the direct testimony of RMP witness A. Robert Lasich, the Marengo Expansion (Marengo II) is a 70.2 MW wind energy generation facility consisting of 39 Vestas 1.8 MW wind turbine generators. According to Mr. Lasich's testimony, the project is expected to be operational by August 2008.[5] A subsequent data response indicates a slightly earlier date of July 2008.

The Marengo Expansion project is located outside Dayton, Washington near the 140.4 MW Marengo wind energy generation facility, which became operational in August 2007.[6] The Marengo Expansion project has exactly 50 percent of the nameplate capacity of the Marengo facility, which consists of 68 Vestas 1.8 MW wind turbine generators.

The expense adjustments and workpapers prepared by RMP for these two projects do not distinguish between the Marengo facility and the Marengo Expansion project, even though they have different operational dates. (See for example, Exhibit RMP (SRM-1S), p. 4.12.1.) In the Company's original filing seeking a test period ending June 2009, RMP projected an O&M expense for the two projects combined of $5,786,073 – which assumed 11 months of Marengo Expansion operation (August 2008 to June 2009).[7] In its

[5] Direct testimony of A. Robert Lasich, p. 22, line 499.
[6] Ibid., p. 18, line 394 & p. 20, line 455.
[7] Exhibit RMP (SRM-1), p. 4.12.1

revised filing, with a test period ending December 2008, the combined O&M expense for the Marengo facilities is only reduced 4.3 percent to $5,540,118 – even though the Marengo Expansion is only operational for 6 months of this period (assuming a revised July 2008 operational date). Of this reduction, about 1.3 percent is attributable to backing out inflation. Clearly, it appears that the reduced period of operation of the Marengo Expansion project in the new test period is not being fully reflected in the updated O&M expense.[8]

Q. What adjustment do you recommend?

A. As the Marengo Expansion project is exactly one-third of the overall capacity of the combined projects, I have imputed one-third of the annual total Marengo O&M expense to it. I have re-calculated the combined Marengo O&M expense to reflect 6 months of operation of the Marengo Expansion project during the test period while accounting for the reduction of costs of 1.3 percent attributable to the test period ending December 2008. These calculations are shown in UAE-WM Exhibit RR 1.4. This adjustment results in a $263,418 reduction in Utah revenue requirement.

[8] In RMP Response to DPU 38.3, the Company indicates that $1,053,572 of the total Marengo O&M expense is attributable to Marengo II project. This means the balance, $4,486,546, is attributable to Marengo I. However, for the test period ending June 2009, this further means the Marengo II O&M expense would be in excess of $2 million, leaving some $3.8 million in O&M expense for Marengo I – 15 percent less than the test period ending 6 months prior. These implied expense combinations are problematic and should be modified per the adjustment I recommend below.

<u>Lakeside O&M Expense</u>

Q. Please explain your reason for proposing an adjustment to the Lakeside O&M Expense.

A. In the Company's original filing seeking a test period ending June 2009, RMP forecasted an O&M expense for the Lakeside generating facility of $4,806,594. In its revised filing, with a test period ending December 2008, the Company forecasted a Lakeside O&M expense that is considerably higher, $5,423,676. The Company's revised filing provides no explanation for this higher expense in the earlier test period. Absent a reasonable explanation, this level of forecasted expense appears implausible.

Q. What adjustment do you recommend?

A. I recommend setting the Lakeside O&M expense no greater than what was projected for the test period ending June 2009. This adjustment is shown in UAE-WM Exhibit RR 1.5, and results in a reduction of $261,500 in the Utah revenue requirement.

<u>Sunnyside Cogeneration Associates Contract Amendment</u>

Q. Please explain your adjustment for the Sunnyside Cogeneration Associates contract.

A. RMP purchases 53 MW of energy and capacity from Sunnyside Cogeneration Associates (SCA) from SCA's facility located in Carbon County, Utah. RMP and SCA recently renegotiated the energy price in the contract, which was approved by the Commission on April 3, 2008 in Docket Nos. 07-305-99, 05-035-46, and 96-2018-01. As stated in the Commission's April 3 Order, RMP estimates that the new energy purchase price for Sunnyside will reduce Utah's revenue requirement by $1.57 million.[9] Given that the renegotiated contract has been approved by the Commission, RMP's revenue requirement should be reduced by this amount, as shown in UAE-WM Exhibit RR 1.6, subject to final calculation as part of net power cost.

I address this matter here separately from net power cost due to the fact that this information was provided by RMP in the Sunnyside dockets on a stand alone basis.

Amortization Period for Revenues from Sales of SO_2 Allowances

Q. Please explain your adjustment for the amortization period for revenues from sales of SO_2 allowances.

A. RMP sells excess SO_2 allowances to other parties. In Docket No. 97-035-01, Utah parties stipulated that the revenues from these sales would be amortized over four years; this approach was approved by the Commission. As shown in RMP Exhibit (SRM-1S), p. 3.2.1, these sales occur with regularity. In 2007, revenue from sales of SO_2 allowances was $14.6 million; in 2008, sales are projected to be $15.9 million.

While the four-year amortization period was reasonable at the time of its adoption, I believe it is preferable to shorten the amortization period to allow customers to realize the benefits from the sales more quickly. Accordingly, I am recommending that

[9] Public Service Commission of Utah, Order, Docket Nos. 07-305-99, 05-035-46, and 96-2018-01, April 3, 2008, p. 6.

the amortization period for sales of SO_2 allowances made after January 1, 2008 be reduced to three years. Further, the amortization schedules for the remaining unamortized balances as of December 31, 2007 for SO_2 sales made before January 1, 2008 should also be accelerated from a four-year to a three-year schedule.

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

A. As shown in UAE-WM Exhibit RR 1.7, page 3, I estimate that this change would reduce the Utah revenue requirement by $2,923,167.

Domestic Production Activities Deduction

Q. What is the Domestic Production Activities deduction?

A. The Domestic Production Activities deduction, sometimes called the Section 199 deduction, was introduced as part of the American Jobs Creation Act of 2004 and became effective for taxable years beginning in 2005. For electric utilities, the Section 199 deduction reduces the amount of the utility's net income associated with electric power generation that is subject to Federal Income Tax. In 2006, this deduction was 3 percent of taxable net income. In 2007, the deduction increased to 6 percent. In 2010, the deduction will increase to its permanent level of 9 percent. At this permanent level, the deduction will effectively reduce the marginal Federal Income Tax rate on generation-related activities to 31.85 percent.

For ratemaking purposes, these tax benefits should be passed through to ratepayers.

Q. Does the Domestic Production Activities deduction apply to distribution and transmission service?

A. No. For that reason, taxable income must be separately calculated for generation-related activities.

Q. How does RMP treat the Domestic Production Activities deduction in its rate filing?

A. RMP projects a Section 199 deduction of $3,776,273 for Calendar Year 2008.

Q. Do you believe this projection is reasonable?

A. No, in my opinion, a Section 199 deduction this low is highly implausible. It implies that pre-tax income for generation-related activities would only be around $63 million on a total Company basis – even though RMP is projecting pre-tax income in excess of $825 million before a rate increase.[10] This would mean that generation-related activities would be responsible for less than 8 percent of the Company's pre-tax operating income – even though the Company's 2006 tax return attributed over 63 percent of its profit to generation.

Further, consider that in RMP's initial filing using a test period ending June 2009, the Company projected a Section 199 deduction of $12,000,521.[11] In addition, the Company's workpapers show a projected Section 199 deduction of $12,076,887 for the

[10] See ROO, RMP Exhibit (SRM-1S), p. 2.2.
[11] RMP Exhibit (SRM-1), p. 7.1.11, line 112.

twelve months ending June 2008, and $12,555,888 for the twelve months ending June 2007.[12]

Q. What is your recommended Section 199 deduction for this proceeding?

A. I recommend using a Section 199 deduction of $12,076,887, based on RMP's estimate for the twelve months ending June 2008, cited above.

Q. What is the impact on Utah revenue requirement from this adjustment?

A. The impact of this adjustment is to reduce Utah revenue requirement by $2,155,932, as shown in UAE-WM Exhibit RR 1.8.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[12] RMP Response to MDR 1.4 (Original).