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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 REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

[COST OF SERVICE / RATE DESIGN]

The UAE Intervention Group (UAE) and Wal-Mart Stores, Inc. ("Wal-Mart") hereby submit the Prefiled Rebuttal Testimony of Kevin C. Higgins on cost of service/rate design issues.

DATED this 3rd day of September, 2008.

/s/______________________________

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 3rd day of September, 2008, on the following:

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BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Rebuttal Testimony of Kevin C. Higgins

on behalf of

UAE and Wal-Mart

[Cost of Service / Rate Design]

September 3, 2008

REBUTTAL 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 jointly sponsored by the Utah Association of Energy Users Intervention Group 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 direct testimony on behalf of UAE and Wal-Mart Stores, Inc. in this 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, Exhibit UAE TP-1.

Overview and Conclusions

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

A. My testimony addresses: (1) rate spread proposals advanced by the Committee of Consumers Services ("CCS"), Utah Industrial Energy Consumers ("UIEC"), and Division of Public Utilities ("DPU"); (2) the rate design proposal advanced by DPU for Schedule 9; (3) cost-of-service arguments advanced by CCS witness Paul Chernick; and (4) the proposals by Western Resources Advocates ("WRA") witness Michael Mendelsohn to expand upon RMP's Schedule 500 proposal and to adopt new tariff provisions pertaining to service for new customers with demands of 5 MW or more.

Q. What conclusions and recommendations do you offer based on your analysis?

A. I offer the following conclusions and recommendations:

(1) I continue to support the general rate spread proposal advanced by RMP. If the Commission elects not to adopt RMP's rate spread proposal, then I recommend adoption of the equal percentage proposal(s) advanced separately by CCS and UIEC as the next best alternative.

(2) I recommend that the Commission reject DPU's proposal to place a disproportionate share of the Schedule 9 increase on the energy charges. In making its proposal to overweight the increase in the energy charge, DPU makes no reference whatsoever to the underlying alignment of demand-related costs and

energy-related costs. Rather, DPU simply proposes to shift cost recovery from demand charges to energy charges in the name of energy conservation. Such a rationale is arbitrary and unreasonable, and creates unwarranted subsidization within rate schedules.

(3) The changes in cost-of-service methodology advocated by CCS witness Paul Chernick are intended to shift responsibility for cost recovery from residential customers to other customer classes – even though it is well understood that a major contributor to the need for new plant on the RMP system is to meet the load growth needs of Utah residential customers. My recommendation is that the Commission should <u>not</u> pursue the cost-of-service approaches advanced by Mr. Chernick. If, in the alternative, the topics identified by Mr. Chernick are to be explored, then consideration ought to be given to alternative approaches sponsored by other parties, such as UAE/Wal-Mart and UIEC.

(4) In my direct testimony I recommended that the Commission reject RMP's proposal to introduce vintage pricing to Utah through its proposed Schedule 500. For the same reasons, I recommend that the Commission reject WRA's proposal to expand the scope of the Schedule 500 proposal. I also recommend that the Commission reject WRA's proposal for new tariff language applicable to new service with demands of 5 MW or more, which would impose onerous conditions on new businesses in Utah. Adoption of WRA's proposals would send a strong anti-development message to businesses that wish to locate

or grow in Utah, undercutting the efforts of Utah policymakers to advance the economic vitality of the state for the wellbeing of its residents.

Rate Spread

Q. In your direct testimony you supported the basic rate spread proposal put forward by RMP. What are the results of adopting your recommended rate spread at the $36.164 million rate increase adopted by the Commission in its erratum order dated August 21, 2008?

A. The results of this rate spread are summarized in Table KCH-1, below.

Table KCH-1
Impact of UAE-WM Rate Spread Proposal

Schedule No.	Description	Current Annual Revenue ($M)	UAE-WM Recommended Increase ($M)	UAE-WM Recommended Percent (%)
1	Residential	$539.7	$17.0	3.15%
6	GS – Large	381.0	6.2	1.61%
8	GS - > 1 MW	114.9	3.6	3.15%
7,11,12,13	Str. & Area Light.	13.1	0.4	3.15%
9	GS – High Voltage	170.4	5.4	3.15%
10	Irrigation	10.0	0.5	5.23%
12	Traffic Light.	0.4	0.01	3.15%
12	Outdoor Light.	0.7	0.02	3.15%
23	GS – Small	97.6	3.0	3.15%
25	Mobile Home Parks	0.8	0.02	3.15%
SpC	Customer A	8.6	0.0*	0.00%
SpC	Customer B	23.3	0.0*	0.00%
SpC	Customer C	22.7	0.0*	0.00%
	Utah Total	$1,383.1	$36.2	2.61%

* UAE-WM recommends that any increase in special contract revenues recognized at the conclusion of this docket be earmarked to further reduce the revenue increase for Schedule 6.

Q. Are you supportive of any rate spread proposals advanced by other parties?

A. Yes. Both CCS and UIEC have proposed equal percentage increases for all rate schedules. While I continue to support RMP's spread proposal, I also believe that the approach advanced separately by CCS and UIEC is within the range of reasonableness. If the Commission elects not to adopt RMP's rate spread proposal, then I would recommend the adoption of the CCS/UIEC proposal as the next best alternative.

Q. What is your assessment of DPU's rate spread proposal?

A. DPU's rate spread proposal is presented in the direct testimony of Abdinasir M. Abdulle. DPU agrees with RMP and UAE/Wal-Mart that it is appropriate to set the increase for Schedule 6 one percentage point below the jurisdictional average. However, DPU disagrees with the RMP/UAE position that Schedules 9 and 23 should receive the same uniform increase as Schedules 1 and 8. Instead, DPU recommends that Schedules 9 and 23 receive a rate increase that is 1.63 percent above the jurisdictional average. In addition, DPU disagrees with the RMP (and UAE/Wal-Mart) proposal to set the increase for irrigation customers at 200 percent of the jurisdictional average, and instead recommends a 10.16 increase for these customers.

One difficulty in assessing DPU's proposal is that it is specifically designed for the 7.5 percent jurisdictional revenue requirement increase proposed by RMP in its supplemental filing; DPU does not propose decision rules for determining rate spread at other, lower, revenue requirements. Consequently, at the lower revenue increase of 2.6 percent approved by the Commission, DPU's specific spread parameters do not appear to be applicable. For example, DPU's recommendation for a 10.16 percent increase for irrigation customers is intended to produce a revenue requirement for this rate schedule that is less than the 200 percent of jurisdictional average recommended by RMP – and at RMP's proposed revenue increase in the Company's supplemental filing, this is the case. However, at the Commission-adopted 2.6 percent jurisdictional increase, 200 percent of system average is just 5.2 percent, well below DPU's specific recommendation of 10.16 percent. DPU does not specify how its proposal for irrigation customers should be translated for an overall rate increase that is less than RMP proposed.

Similarly, DPU's recommendation that Schedules 9 and 23 should be assigned a rate increase that is 1.63 percent greater than the jurisdictional average is tied to the Company's earlier proposed revenue increased of 7.5 percent. Presumably, DPU's proposed mark-up over the jurisdictional average should be scaled back in light of the smaller Commission-approved increase, but DPU's testimony does not address how this could be accomplished.

Q. Do you have any other comments regarding DPU's proposed rate spread?

A. DPU's recommendation for the treatment of Schedule 9 is based on the cost-of-service results presented in RMP's filing. However, as I pointed out in my direct testimony, RMP's treatment of the MSP rate mitigation cap in its class cost-of-service analysis contains a conceptual error that overstates the cost responsibility of Schedule 9. The presence of this conceptual error weakens DPU's case for singling out Schedule 9 for an increase above the uniform amount.

Q. What is your recommendation to the Commission regarding DPU's rate spread proposal?

A. I recommend against adopting DPU's rate spread proposal. I make this recommendation in part because DPU's rate spread proposal does not have explicit decision rules that describe how it would apply over varying revenue requirements, including the final rate increase adopted by the Commission. Because the rate spread recommended by RMP (and UAE/Wal-Mart), as well as the equal percentage approach recommended by CCS and UIEC, produce reasonable results, one of these options should be selected instead.

<u>Schedule 9 Rate Design</u>

Q. What has DPU proposed with respect to Schedule 9 rate design?

A. As presented in the direct testimony of DPU witness Abdinasir M. Abdulle, DPU is recommending that Schedule 9 customers receive a higher percentage increase in the energy charge relative to the demand charge.[1]

Q. What is DPU's justification for this proposal?

A. The justification offered by DPU is that adopting higher energy charges "encourages energy conservation." Dr. Abdulle states that he believes this approach will help curb the summer peak.

Q. What is your assessment of this proposal?

A. I strongly disagree with the rationale underlying DPU's proposal. For classes that are demand-billed, such as Schedule 9, demand charges should be set at levels sufficient to recover each class's demand-related costs and energy charges should be set to recover energy-related costs. If these costs and charges become misaligned, it creates unwarranted subsidies among customers within the affected rate schedule. In making its proposal to overweight the increase in the energy charge, <u>DPU makes no reference whatsoever to the underlying alignment of demand-related costs and energy-related costs</u>. Rather, DPU simply proposes that its recommended incremental increase for Schedule 9 (relative to RMP's proposed increase) be applied exclusively to the Schedule 9 energy charges. Such an approach shifts cost recovery from demand charges to energy charges without a clear basis in cost causation, with the sole rationale being energy conservation. Such a rationale is arbitrary and unreasonable.

Q. Please explain why such an approach to pricing is unreasonable.

Firstly, an approach that shifts cost recovery from demand charges to energy charges in the name of energy conservation incorrectly presumes that the only important price signal is that sent by the energy charge – it ignores the need to send a price signal for demand, i.e., capacity. Yet, providing the resources to meet RMP's growing capacity needs is an expensive proposition: sending a proper price signal for demand is every bit as important as sending a proper price signal for energy. DPU's approach ignores this point entirely.

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[1] Direct testimony of Abdinasir M. Abdulle, p. 22, line 631 to p. 23, line 646.

Secondly, a policy that purposefully understates the price of demand while overstating the price of energy creates unwarranted subsidies within the affected rate schedules, and therefore, is patently inequitable. In the case at hand, higher-load-factor customers would be disproportionately penalized through the higher energy charges, while lower-load-factor customers would disproportionately benefit from the lower demand charges. This pattern is evident by inspecting DPU Exhibit 16, which shows the rate impacts on Schedule 9 customers: as customer load factor increases, so does the impact of the rate increase. Specifically, the rate increase for the higher load-factor customers illustrated in DPU Exhibit 16 is 0.3 percent greater than for lower-load-factor customers in the winter, and up to 0.7 percent greater in the summer.[2] While the magnitude of this impact is modest, adoption of the rationale proposed by DPU would be an unwelcome precedent. If DPU's intent is to send a stronger price signal during the summer and winter peaks, then the proper place to accomplish that objective is to increase the differential between the energy charges in the on-peak and off-peak periods – not shifting cost recovery between demand and energy.

Q. What is your recommendation on this issue?

A. I recommend that the Commission reject DPU's proposal to place a disproportionate share of the Schedule 9 increase on the energy charges. Instead, the demand charge and the energy charges should be increased in the same proportion as proposed by RMP.

[2] I ignored the results shown in DPU Exhibit 16 for a 6,000 kW customer consuming 3,942,000 kWh per month, assuming the increases in excess of 20 percent during the summer to be in error.

Class Cost of Service

Q. Have you reviewed the testimony of CCS witness Paul Chernick on the topic of class cost-of-service?

A. Yes, I have.

Q. What comments do you have on Mr. Chernick's positions?

A. Mr. Chernick explores five general propositions for changing RMP's cost allocation methodology. Four of the five propositions shift costs from residential customers to Schedule 9 customers. The fifth proposition shifts costs from residential customers to commercial customers.

My understanding of CCS's testimony as a whole is that CCS is not seeking adoption of the proposals discussed by Mr. Chernick at this time. Consequently, I will not present a comprehensive rebuttal to these propositions in this testimony. Instead, I will identify a number of the concerns with several of the propositions Mr. Chernick discusses. Any absence of comment on my part on an aspect of Mr. Chernick's testimony does not signify concurrence with Mr. Chernick's position.

Q. Please proceed. What are some of your concerns with adoption of the peaker method for classifying and allocating production plant costs in Utah as discussed by Mr. Chernick?

A. The underlying premise of the peaker method is that a utility would only incur production plant costs greater than the cost of a peaking plant (e.g., combustion turbine) in order to provide energy – not capacity. Following this reasoning, the only production plant costs that are classified as demand-related is the portion equivalent to the cost of a peaking plant – the rest is classified as energy. The implications of this approach for cost allocation are fairly straightforward: it shifts cost responsibility for production plant from customer classes whose usage is relatively peaky to classes whose usage is relatively flat.

A significant concern with the peaker approach is that the portion of production plant cost deemed to be demand-related (i.e., capacity-related) under this approach bears little resemblance to the true cost consequences of what actually has occurred – and continues to occur – on RMP's system when the utility responds to increased capacity requirements by acquiring new generation plant.

Let's start with RMP's coal fleet. The peaker method would reclassify coal generating units as primarily energy-related, and only the portion of coal production plant equivalent to the capacity cost of a peaking plant would be classified as demand-related. Central to the reasoning behind the peaker method is the following assumption: rather than having assembled its current coal generation fleet, RMP just as easily could have opted to serve its highest maximum loads using combustion turbines or other peaking capacity. The implication is that the utility, faced with this choice, rationally would – and could – have built only combustion turbines, but for energy cost considerations. However, this simplification ignores the planning reality faced by electric utilities at the time RMP (and its predecessors) assembled the fleet of coal plants that are the subject of today's cost-of-service analyses.

The first problem with the underlying assumption of the peaker method is that prior to the repeal of the Power Plant and Industrial Fuel Use Act in 1987, electric utilities *could not* just as easily install gas-fired peaking facilities as other technologies, as the use of natural gas and petroleum for electric power generation was severely restricted under Federal law. Even though that Act allowed an exception for peaking plants, that exception was only permitted through petition to the Secretary of Energy. Moreover, in the years prior to the adoption of the Power Plant and Industrial Fuel Use Act in 1978, the availability of natural gas supplies for electric power generation had become notoriously unreliable in the United States, as the country was buffeted by natural gas supply shortages – due in large part to a Federal regulatory pricing system that had broken down.

This historical framework is especially applicable to RMP, as the first unit at every one of the Company's current coal generation facilities came on line prior to 1980. The assumptions underlying the peaker method were simply not applicable when RMP's coal fleet was planned and built. Prior to 1980, any prudent utility seeking to add reliable capacity needed to acquire a plant that did not use natural gas. The most feasible capacity option at that time for RMP was coal. Given the conditions under which RMP assembled its coal generation fleet, the cost of these plants can only reasonably be viewed as primarily capacity-related. Applying the peaker method to classify these plant costs would be an exercise in revisionist history.

With respect to RMP's newer plants, even though the Power Plant and Industrial Fuel Use Act has long been repealed, I nonetheless challenge the relevancy of using peaking plants for determining the cost allocation consequences of adding new generation capacity for this utility. In recent years, RMP's response to its increasing capacity needs has been to construct combined-cycle generating plants – not simple cycle plants – because the former are so much more efficient than the latter. Consider this excerpt from the Commission's order in Docket No. 03-035-29, approving the Certificate of Convenience and Necessity for the Company's Currant Creek plant:

> Several witnesses express concern that bids in the peak bid category of RFP 2003-A are measured against a cost based resource that is typically characterized as a baseload unit, that is, a resource that operates economically for most hours of the year rather than just for peak hours of demand. However, the record shows that this configuration is an appropriate design when gas prices are high and when the equipment can effectively dispatch daily. No party presented evidence that the gas price assumptions used by PacifiCorp are unreasonable **nor disputed the ability of combined-cycle equipment to provide cost-effective peaking capacity.** Navigant testifies that ten bids in the 2005 category are based on combined cycle technology and that two include duct firing and PacifiCorp testifies that four of these made the short list. Indeed, Spring Canyon Energy witnesses testify that they did not consider bidding a simple cycle combustion turbine because a combined-cycle facility has a much better heat rate and a much lower cost to the rate payer. **Further, they state that the only reason for considering a simple-cycle facility is to meet an online date not possible for a combined-cycle facility. Calpine testifies that an economic way to provide peaking power in 2005 is to stage construction of a combined cycle by starting with a simple cycle in the first year. In fact, no party in this case testifies that a simple cycle combustion turbine without staged conversion to combined cycle is least cost to fill the need identified in IRP 2003 for the resource added in 2005.** [Emphasis added.] Order at 12.

It is clear that in Utah, and for RMP's system generally, combined-cycle units have been selected to meet the system's increased capacity requirements. The peaker method advocate would respond that such decisions simply reflect energy cost differentials; my response is that technologies that are so inefficient that they are unlikely to actually be built to meet capacity needs should not be used to set the value of capacity for cost allocation purposes, for to do so is to under-assign cost responsibility of the new plants to classes whose growth in capacity needs is making the new plants necessary.

Q. Do you have any comments on Mr. Chernick's discussion of the allocation of firm sales revenue?

A. Yes. Currently, firm sales revenue is allocated on the same basis as most production plant: 75 percent demand, 25 percent energy. In my opinion, this consistency is reasonable, as it allocates the benefit from the sales revenue in the same manner as the costs of the production plant that makes these sales possible. Mr. Chernick describes a complex alternative approach to allocating the benefit of off-system sales revenues to customer classes based on the extent to which classes are *not* using the system's generation for each month in which sales are made.

It appears to me that Mr. Chernick's approach does not square very well with his preference for the allocation of production plant generally, which is to shift cost responsibility from classes whose usage is relatively peaky to classes whose usage is relatively flat. That is, Mr. Chernick advocates that production plant costs in the first instance should be classified primarily as energy-related – as opposed to capacity-related. But then for the purpose of allocating sales revenue benefits, Mr. Chernick advocates for assigning benefits to classes based on a notion of "avoided *capacity*" attributable to each class. These two approaches advocated by Mr. Chernick strike me as fundamentally inconsistent.

Q. Do you have any comments on Mr. Chernick's discussion of the classification and allocation of distribution plant?

A. Yes. Mr. Chernick advocates for classifying a significant portion of distribution plant on an energy basis. I strongly disagree. Distribution costs are customer-related and demand-related – they are not energy-related. There is a strong consensus on this point. For example, in discussing distribution cost of service, the NARUC Cost Allocation Manual states: "…[A]ll costs of service can be identified as energy-related, demand-related, or customer-related. **Because there is no energy component of distribution-related costs, we need to consider only the demand and customer components**." [3] [Emphasis added] To further appreciate this point, one can make the following inquiry with respect to distribution plant: to what extent could distribution plant investment be reduced if the customer configuration and demand requirements remained constant, but energy usage declined? The answer is very little, if anything – which is an important reason why distribution plant is generally not classified or allocated on the basis of energy.

[3] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 89.

In my opinion, any revamping of distribution cost classification and allocation in Utah should focus on a different matter: the significant understatement of customer-related costs in the classification and allocation of distribution plant in Utah. In Utah, RMP allocates primary lines, secondary lines, and line transformers exclusively on the basis of demand, even though a portion of these costs are more properly classified and allocated as customer-related costs, consistent with the guidelines in the NARUC Cost Allocation Manual.[4] The systematic understatement of customer-related costs in the current methodology unreasonably shifts cost responsibility to customers on Schedules 6 and 8. If RMP's methodology for classifying and allocating distribution plant is to be reevaluated, then this issue should be made a high priority.

Q. In summary, what is your recommendation to the Commission with respect to the five general propositions Mr. Chernick presents with respect to the classification and allocation of costs?

A. The propositions presented by Mr. Chernick are intended to shift responsibility for cost recovery from residential customers to other customer classes – even though it is well understood that a major contributor to the need for new plant on the RMP system is to meet the load growth needs of Utah residential customers. My recommendation is that the Commission should <u>not</u> pursue the approaches proposed by Mr. Chernick. If, in the alternative, the topics identified by Mr. Chernick are to be explored, then consideration ought to be given to alternative approaches sponsored by other parties, such as UAE/Wal-Mart and

[4] Ibid., p. 89.

UIEC. In light of the significant time requirements demanded by upcoming proceedings, such an exercise may not be the best use of parties' resources at this time.

<u>**Schedule 500 and Beyond**</u>

Q. Do you have any comments on the proposal by WRA witness Michael Mendelsohn to expand upon RMP's Schedule 500 proposal and to add new tariff language applicable to new service with demands of 5 MW or greater?

A. Yes. In its filing, RMP has proposed that Schedule 500 be applied to new or growing customers with incremental loads of 10 MW or greater. Mr. Mendelsohn proposes to go further by extending Schedule 500 to loads starting at 5 MW. He also proposes to add tariff language that would require all new loads that are 5 MW or greater to enter into seven-year take-or-pay contracts for electric service. Under WRA's proposal, affected new customers would be required to pay a 75 percent demand ratchet going back as far as seven years. Further, if the customer terminates service, the customer would be liable for liquidated damages equal to the nominal value of all future customer, facilities, and power charges that otherwise would have been incurred for the remainder of the contract term had the customer continued to take service at 75 percent of the highest monthly demand level it had previously experienced. In other words, if someone is going to start a new business in Utah, they must commit in advance to pay 75 percent of the power costs they are projected to incur for the next seven years, subject to liquidated damages.

In my direct testimony, I provided an extensive response to RMP's Schedule 500 proposal. That response applies equally to WRA's proposal to expand the scope of the proposal and will not be repeated here.

WRA's proposed "new service" provision is wrapped in the cloak of "protecting other customers," but primarily appears to be an attempt to stifle economic development in Utah by requiring onerous contracting provisions for new businesses. As I pointed out in my direct testimony, Utah's projected average annual industrial load growth over the next five years is approximately one-half of one percent of the current demand on the PacifiCorp system. This level of growth does not warrant consideration – let alone adoption – of radical pricing and tariff schemes. WRA's proposals should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.