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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. 09-035-23**

PREFILED REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT, COST OF SERVICE, RATE SPREAD]

The UAE Intervention Group ("UAE") hereby submits the Prefiled Rebuttal Testimony of Kevin C. Higgins on revenue requirement, cost of service and rate spread issues.

DATED this 12th day of November, 2009.

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

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 12th day of November, 2009, on the following:

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BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Rebuttal Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 09-035-23

[Revenue Requirement, Cost of Service, Rate Spread]

November 12, 2009

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

A. Yes, I am.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony primarily responds to the rate spread and cost of service testimony filed by witnesses for the Division of Public Utilities ("DPU"), Office of Consumer Services ("OCS"), The Kroger Co. ("Kroger"), the Utah Industrial Energy Consumers ("UIEC"), and Wal-Mart Stores, Inc. / Sam's West, Inc. ("Wal-Mart").

I also respond to aspects of the direct testimony filed by OCS witness Philip Hayet and DPU witness William A. Powell on the subject of wind integration costs.

Q. What are the primary conclusions of your rebuttal testimony?

A. With respect to rate spread, I agree with Kroger witness Stephen J. Baron that the rate spread proposal by RMP witness William Griffith is reasonable at RMP's proposed revenue requirement. I also conclude that the rate spread suggested by DPU witness Thomas C. Brill in his <u>supplemental</u> direct testimony and UIEC witness Maurice Brubaker in his direct testimony fall within the range of reasonable outcomes.

I compare the "revenue apportionment" approach to rate spread that I propose in my direct testimony to the proposal advanced by OCS witness Daniel E. Gimble and show that my approach produces results for Residential customers that are similar to Mr. Gimble's recommendations over a considerable range of outcomes. However, my approach produces results for Schedule 9 customers that are considerably more moderate than Mr. Gimble. For the reasons expressed in my testimony, I strongly believe that my proposed approach is more reasonable and better serves the public interest.

DPU's <u>initial</u> rate spread proposed that the entire amount of DPU's initially-proposed revenue increase of $8.5 million be funded by just two customer classes, Schedules 9 and 10. This proposal is unreasonable and should be rejected by the Commission. In reaching its recommendation, DPU relied upon cost-of-service results that are highly suspect. DPU's proposal also disproportionately assigns the cost of paying for growth to classes that are growing least. Further, DPU does not adequately consider the implications of targeting Utah's industrial customers for so large an increase in the midst of a major recession.

Turning to cost-of-service issues, I generally support the thrust of DPU witness Joseph Mancinelli's position with respect to the need for consistency between inter-jurisdictional cost allocation and class cost allocation. However, I am reserving judgment on specific changes until I have had the opportunity to review RMP's response, as there are likely to be instances in which there are valid reasons for deviation. I also agree with his conclusion that the MSP rate mitigation cap is directly related to production and should be entirely applied to the production function. However, I object to his proposal to re-allocate wind generating plant on a 100 percent energy basis. While I agree that wind generation plant can reasonably be considered as primarily energy-related, I am concerned that adopting significant changes to allocation factors in isolation may potentially unwind the balancing of interests reflected in the approach to inter-jurisdictional allocations used in Utah. Moreover, if a change in classification of wind generation plant is adopted, I disagree that 100 percent energy is appropriate, in light of the 20 percent capacity value that RMP assigned to wind generation in its 2004 IRP. Finally, if a change in classification of costs is adopted, there must be a corresponding change to the classification of wind generation benefits, specifically the allocation of renewable energy tax credits and "Green Tag" renewable energy credits.

I strongly object to OCS witness Paul Chernick's proposal to change the classification of generation plant in future RMP cost-of-service studies such that at least 50 percent of generation plant would be classified as energy-related. The Commission has already determined that a 75 percent demand-related and 25 percent energy-related split is the appropriate basis for allocating production and transmission costs to classes in the Utah jurisdiction. Further, Mr. Chernick's proposal is inconsistent with the Commission's expressly-stated preference for consistency between inter-jurisdictional cost allocation and class cost allocation. In my rebuttal testimony, I explain why the application of Mr. Chernick's argument to RMP's coal fleet is an exercise in revisionist history and examine the theoretical weaknesses in the "peaker methodology" upon which he relies.

In my view, both the OCS proposal to classify generation plant as at least 50 percent energy and the DPU proposal to allocate wind plant 100 percent on energy suffer from the following common defects: they both deviate from the Commission-approved and historical 75/25 classification split in this state and they both address one allocation issue in isolation and fail to examine other challengeable allocations implicit in the existing inter-jurisdictional "compromise." And as any significant change in cost classification or allocation methodology is assured to benefit some customer classes while shifting costs to others, they both invite others to open up a piecemeal attack on the entire cost allocation methodology.

With respect to wind integration costs, OCS witness Philip Hayet correctly noted that the final approved BPA charges for wind integration service are lower than the rates projected by RMP in its direct filing. Consequently, any final adjustment adopted by the Commission for BPA wind integration charges should be additive to the wind integration adjustment I am recommending.

From a conceptual standpoint, I view intra-hour wind integration costs for "regulating up" to be a valid expense to be recovered from ratepayers. However, based on the testimony of DPU witness William A. Powell, to the extent that RMP has not met its burden of proof in demonstrating its intra-hour wind integration costs, an adjustment may be warranted. At the same time, my recommendation for treatment of inter-hour wind integration costs is unchanged from my direct testimony: I continue to recommend that RMP's wind integration charges be reduced by $2.08/MWh to remove the cost of assumed transactional losses for performing inter-hour wind integration.

RATE SPREAD

Response to Thomas C. Brill (DPU)

Q. What rate spread has Dr. Brill proposed in this proceeding?

A. Dr. Brill has presented two discrete rate spread proposals, one in DPU's initial direct filing made on October 8, 2009, and another made in DPU's supplemental filing dated October 29, 2009. I assume that the proposal presented by Dr. Brill in his supplemental direct testimony represents DPU's official rate spread recommendation at this juncture in the proceeding; nevertheless, I will respond to DPU's initial proposal in this rebuttal testimony as well.

Q. Please proceed. What rate spread is DPU proposing in its supplemental filing?

A. In its supplemental filing, DPU is recommending an overall revenue reduction for RMP of $0.9 million. DPU's proposal for spreading this revenue change is presented on page 5 of Dr. Brill's supplemental direct testimony. Dr. Brill is recommending an across-the-board equal percentage revenue change of 0 percent for all rate schedules, except Residential, which would receive a revenue reduction of $0.9 million, or (0.16) percent.

Q. What is your assessment of DPU's proposal in its supplemental filing?

A. I believe the rate spread proposed in DPU's <u>supplemental</u> filing is within the range of reasonable outcomes at the DPU's proposed revenue requirement decrease of $0.9 million. By way of comparison, in my direct testimony, I recommended a rate spread approach based on revenue apportionment that is applicable across a broad range of revenue requirement determinations. In Table KCH-R1, below, I compare the results of my recommended approach to DPU's proposed rate spread at DPU's recommended revenue requirement. As shown in the table, at an overall revenue requirement change of - $0.9 million, my approach provides for a somewhat larger revenue requirement reduction for Residential customers of $4.7 million (- 0.82 percent), while rates for Schedules 8, 9 and 10 would be increased by 1.08 percent. Viewed on the whole, DPU's supplemental proposal and my recommendation do not produce very dissimilar results at this particular revenue requirement outcome.

Table KCH-R1

Comparison of UAE and DPU Rate Spreads @ $0.9 Million Revenue Decrease

		DPU Supplemental Recommended Spread		UAE Recommended at DPU Supp. Decrease	
Class	Schedule	($000)	(%)	($000)	(%)
Residential	1,3	($915)	(0.16%)	($4,702)	(0.82%)
GS – Large	6,6A,6B	$0	0.00%	$527	0.13%
GS – 1 MW+	8	$0	0.00%	$1,264	1.08%
GS – High Voltage	9,9A	$0	0.00%	$1,723	1.08%
Irrigation	10,10TOD	$0	0.00%	$118	1.08%
GS – Small	23	$0	0.00%	$133	0.13%
Other	Various	$0	0.00%	$23	0.02%
Total Retail		($915)	(0.06%)	($915)	(0.06%)

Q. You stated that you have recommended a rate spread approach that is applicable to a broad range of revenue requirement outcomes. Does DPU also present an approach that is applicable to a broad range of revenue requirement outcomes?

A. No. DPU does not provide an approach; rather, DPU only proposes discrete rate spreads at the single point(s) associated with its recommended revenue requirement(s). In my opinion, the absence of a more generally applicable approach in DPU's position significantly diminishes the usefulness of DPU's recommendation, particularly in a proceeding (such as this) in which revenue requirement and rate spread are to be determined simultaneously.

Q. Can inferences be drawn from DPU's rate spread recommendation proposed in its initial direct filing?

A. Only on a very limited basis. In its direct filing, DPU provided a rate spread recommendation associated with a revenue requirement increase of $8.5 million. In this proposal, all rate schedules would receive a revenue change of 0 percent, except Schedules 9 and 10, which would absorb the entire rate increase "in proportion to their contribution to the cost of service."[1] This impact amounts to a 4.9 percent increase for Schedule 9 and a 5.4 increase for Schedule 10.

The revenue requirement difference between DPU's supplemental filing and its initial filing is relatively modest: $9.3 million, or 0.68 percent of retail revenues – yet the rate spread implications for Schedules 9 and 10 are dramatic, swinging 4.9 percent and 5.4 percent, respectively, between these two revenue scenarios.

Q. Do DPU's direct filings provide any rate spread guidance for revenue requirement outcomes in excess of the $8.5 million proposed in DPU's initial filing?

A. No. DPU provides no rate spread recommendations for revenue requirement outcomes in excess of $8.5 million. Whether DPU would continue to propose that Schedules 9 and 10 bear the entire burden of such an increase, or whether DPU would propose some other arrangement, is not expressed in DPU's filed case. Indeed, parties have no indication as to whether DPU would propose

[1] Direct testimony of Thomas C. Brill, PhD, p. 15, lines 298-300.

something that has a nexus to its current proposal(s) or whether DPU would propose something completely different.

Q. What is your assessment of DPU's rate spread proposal in its initial filing?

A. In my opinion, DPU's initial rate spread places an undue burden on Schedules 9 and 10. In proposing that the entire rate increase fall on these two rate schedules, DPU relied upon cost-of-service results that are highly suspect; indeed, DPU's own witness, Jonathan Nunes, raises serious questions concerning the quality of the RMP load research estimates that are critical inputs into the class cost-of-service study, concluding that the resulting class load estimates do not appear to meet the PURPA standard. Mr. Nunes goes so far as to state that the "poor performance of the Company's load research program appears to be a long-standing problem."[2] Yet, while Dr. Brill acknowledges that "Mr. Nunes testimony casts considerable doubt upon the load forecasting that is an input into the cost of service analysis," and that, therefore, the cost-of-service results of DPU's witness, Mr. Mancinelli, "have a margin of error that he is unable to address," DPU nevertheless relied on these results to assign its entire proposed rate increase to just two rate schedules "in proportion to their contribution to the cost of service."[3] DPU's reliance on such questionable cost-of-service results in reaching a one-sided rate spread recommendation is misplaced.

Although DPU did not attempt to calculate the referenced "margin of error" in the RMP/DPU cost-of-service results, I did perform such an analysis for

[2] Direct testimony of Jonathan Nunes, p. 19, lines 243-244.
[3] Direct testimony of Thomas C. Brill, PhD, p. 15, lines 290-300.

the census-measured Schedules 8 and 9, which was presented in my direct testimony. As I explained in that testimony, the potential revenue requirement error for Schedule 9 is as much as 5 percentage points; that is, the revenue deficiency for Schedule 9 (at RMP's overall filed revenue requirement proposal) decreases from 11.87 percent to 6.85 percent when the cost-of-service analysis is rerun using the jurisdictional loads assigned to Utah, rather than RMP's sample estimates. UIEC witness Maurice Brubaker, who also presents a detailed and persuasive critique of the load measurement problems in the RMP cost-of-service study, similarly identifies a substantial potential error in his direct testimony.[4] With a potential error of this magnitude in the cost-of-service results for Schedule 9, DPU's initial proposal to assign the lion's share of the system revenue increase to Schedule 9 is disproportionate and unreasonable.

Q. What rate spread results from your recommended approach at the $8.5 million revenue increase initially proposed by DPU?

A. The rate spread from my recommended approach is presented in Table KCH-R2, below, where it is also compared to DPU's initial rate spread. As shown in the table, at an $8.5 million increase, my recommended approach is slightly *more* favorable to Residential customers than DPU's recommendation; and while my approach results in a higher-than-average increase for Schedules 8 9, and 10, it is far less impactful on Schedules 9 and 10 than DPU's proposal. Given the full range of considerations that must be taken into account in

[4] UIEC Exhibit__(MEB-3), p. 2.

determining rate spread, I believe my approach produces a more balanced and reasonable outcome.

Table KCH-R2

Comparison of UAE and DPU Rate Spreads @ $8.5 Million Revenue Increase

		DPU Direct Recommended Spread		UAE Recommended at DPU Direct Increase	
Class	Schedule	($000)	(%)	($000)	(%)
Residential	1,3	$0	0.00%	($870)	(0.15%)
GS – Large	6,6A,6B	$0	0.00%	$3,292	0.81%
GS – 1 MW+	8	$0	0.00%	$2,067	1.76%
GS – High Voltage	9,9A	$7,868	4.93%	$2,816	1.76%
Irrigation	10,10TOD	$593	5.41%	$193	1.76%
GS – Small	23	$0	0.00%	$826	0.81%
Other	Various	$0	0.00%	$138	0.13%
Total Retail		$8,461	0.57%	$8,461	0.57%

Q. Do you have other reasons for objecting to DPU's initial rate spread, in addition to DPU's reliance on questionable cost-of-service results?

A. Yes. In assigning the full burden of the system rate increase to Schedules 9 and 10, DPU fails to take into consideration that the cost of paying for growth is being disproportionately assigned to classes that have been growing least. Further, DPU does not adequately consider the implications of targeting Utah's industrial customers for so large an increase in the midst of a major recession.

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

A. For the reasons discussed above, I recommend that DPU's initial rate spread recommendation <u>not</u> be used to guide the determination of the spread of rates. If the final revenue requirement adopted results in a rate decrease of $0.9 million as proposed by DPU, the spread recommendation in DPU's supplemental testimony is reasonable. As a general proposition, however, I believe my "revenue apportionment" recommendation is the most appropriate approach for spreading rates across the full range of revenue requirement outcomes being proposed in this proceeding.

<u>Response to Daniel E. Gimble (OCS)</u>

Q. What rate spread has OCS proposed in this proceeding?

A. OSC is recommending an overall revenue reduction for RMP of $5.9 million, or (0.40) percent. OCS's proposal for spreading this revenue change is presented on page 3 of Mr. Gimble's direct testimony. Mr. Gimble proposes a revenue reduction of 1.5 percent for Residential customers, as well as a reduction of approximately 0.4 percent for Schedules 6, 10, and 23. He recommends no revenue change for Schedule 8. According to OCS's proposal, the only customer class that would receive an increase is Schedule 9, which would see its rates increase by 3.0 percent.

Q. How does Mr. Gimble's recommendation compare with the rate spread that would result from applying your recommended approach using OCS's recommended revenue reduction of $5.9 million?

A. This comparison is shown in Table KCH-R3, below. As shown in the table, the revenue reduction for Residential customers produced using my approach is 1.2 percent – very similar to OCS's proposed reduction of 1.5 percent. My approach also produces reductions for Schedules 6 and 23 that are similar to those recommended by OCS. The primary difference between our recommendations is the magnitude of the recommended increase for Schedule 9: 0.72 percent in my recommendation versus 3.0 percent in OCS's recommendation.

Table KCH-R3

Comparison of UAE and OCS Rate Spreads @ $5.9 Million Revenue Decrease

		OCS Direct Recommended Spread		UAE Recommended at OCS Decrease	
Class	Schedule	($000)	(%)	($000)	(%)
Residential	1,3	($8,560)	(1.50%)	($6,738)	(1.18%)
GS – Large	6,6A,6B	($1,632)	(0.40%)	($942)	(0.23%)
GS – 1 MW+	8	$0	0.00%	$838	0.71%
GS – High Voltage	9,9A	$4,791	3.00%	$1,142	0.72%
Irrigation	10,10TOD	($47)	(0.43%)	$78	0.71%
GS – Small	23	($409)	(0.40%)	($235)	(0.23%)
Other	Various	($39)	(0.04%)	($38)	(0.04%)
Total Retail		($5,896)	(0.40%)	($5,896)	(0.40%)

Q. What justification does Mr. Gimble offer in singling out Schedule 9 for a significantly greater increase than other rate schedules?

A. Mr. Gimble identifies two factors supporting this recommendation – the rate of return indices produced by RMP's cost-of-service study and the pattern of class cost-of-service results since 2003.

Q. Do you have any comments on Mr. Gimble's application of these factors?

A. Yes. In general, I agree with using class rate-of-return information and the pattern of results over time to move classes closer to cost of service, as Mr. Gimble proposes. However, as I explained in my direct testimony, because RMP *allocates*, rather than calculates, income tax responsibility to customer classes at current revenues, the class rate-of-return results produced by RMP's cost-of-service calculation are overstated for classes earning above the average return and understated for classes earning below the average return. To the extent that Mr. Gimble has relied upon RMP's presentation of class relative rates of return in reaching his rate spread recommendation, his proposal may have been influenced by the exaggeration built into RMP's results.

Second, as I discussed in my direct testimony and in my response to Dr. Brill, above, the RMP cost-of-service results used in supporting Mr. Gimble's recommendation are highly questionable due to data quality problems. Moreover, Mr. Gimble's reference to cost-of-service results over the past several years provides no greater assurance that his recommendation is based on accurate information: as Mr. Nunes has stated, the poor performance of the Company's load research program appears to be a long-standing problem. Indeed, RMP's decision to cease calibrating non-census loads to the Utah jurisdictional load represents a methodology change that dates back to the issuance of a Load Research Working Group Report in July 2002, corresponding to the period Mr. Gimble analyzes in his testimony. As it turns out, the cost-shifting implications of a relatively obscure, and quite possibly problematic, recommendation in that report – which, to my knowledge, was never adopted by the Commission – are only now becoming more widely understood.

Q. Does OCS also express concerns with the quality of the data used in RMP cost-of-service studies?

A. Yes. Mr. Gimble states that RMP's irrigation load data is "highly inaccurate" and "unsuitable for use" in RMP's cost-of-service study.[5] Because of OCS's concern about the quality of irrigation load data, Mr. Gimble recommends completely ignoring RMP's cost-of-service results for irrigation customers, and adjusting Schedule 10 rates by the jurisdictional average.

Q. Do you have any comments with respect to OCS's position on data quality?

A. Yes. As explained in the testimony of Mr. Nunes, the data quality problems are more widespread than problems with irrigation load data. Whereas OCS's proposed rate spread takes into account concerns regarding irrigation load data, it fails to recognize the implications of data quality problems for other customer classes, most notably Schedule 9.

Q. Does OCS provide any rate spread guidance if the Commission-authorized revenue change differs from OCS's own proposal?

A. Yes. In such an event, Mr. Gimble recommends that there should be no Residential rate increase if the overall rate increase in this proceeding is less than $10 million, and further, that there should be no Residential rate increase in excess of 1.0 percent. Mr. Gimble also recommends that Schedules 10, 23, and 25 should receive revenue changes equal to, or close to, the jurisdictional average.

Q. Do you have any comments with respect to OCS's proposed guidance?

A. Yes. Similar to Mr. Gimble's recommendation, the revenue apportionment approach I am recommending in my direct testimony would not result in a rate increase for Residential customers unless an overall revenue

[5] Direct testimony of Daniel E. Gimble, p. 4, lines 84-87.

increase exceeded $10.6 million. However, I do not concur with Mr. Gimble's recommendation for a 1.0 percent cap on a Residential rate increase under all circumstances. Consistent with the approach I have proposed, if the overall revenue increase exceeds $24.6 million, then I believe it is necessary for Residential customers to share to a larger extent in the increase to ensure a reasonable outcome for all customer classes.

<u>Response to Intervenor Rate Spread Proposals</u>

Q. Do you have any comments on the rate spread testimony put forward by other intervenors?

A. Yes. In his direct testimony, Kroger witness Stephen J. Baron concluded that the rate spread proposal by RMP witness William Griffith is reasonable at RMP's proposed revenue requirement. I agree with his conclusion.

On behalf of UIEC, Mr. Brubaker recommended an equal percentage increase for all customer classes, based on his analysis of cost-of-service. In my opinion, his proposal is within the range of reasonableness.

Wal-Mart witness Steve W. Chriss supports moving customer classes closer to cost-based rates. I agree with this objective, although as discussed at length in my direct and rebuttal testimony, there are significant questions in this case regarding the quality of the data used to determine cost of service. Moreover, as also discussed, additional factors need to be considered in determining a just and reasonable rate spread. Mr. Chriss indicates that Wal-Mart does not necessarily oppose a rate mitigation mechanism. However, as I understand his description of the mechanism, no rate schedule would pay more than its cost of service. Thus, it is not clear to me how the mitigation would be funded under Mr. Chriss' proposal.

Summary of UAE Rate Spread Rebuttal

Q. Do you have any summary comments to offer on the subject of rate spread?

A. Yes. In this rebuttal testimony, I have compared the results of the revenue apportionment approach I recommended in my direct testimony to the rate spread proposals of DPU and OCS. It is significant to note that my recommended approach produces results that are <u>more favorable</u> for Residential customers than DPU's proposal at each of DPU's recommended revenue outcomes. It also produces results for Residential customers that are comparable to OCS's recommendations at a revenue decrease of $5.9 million, as well as for revenue increases up to $24.6 million. The key difference between my approach and the proposals of DPU and OCS is the treatment of Schedule 9: while I propose a higher-than-average increase for this customer class, my proposed increase is much more tempered than either of these two parties recommend. I believe that achieving a more tempered result for Schedule 9, while providing comparable (or more favorable) results for Residential customers, demonstrates the balance and reasonableness of the rate spread approach I have put forward. I continue to recommend its adoption by the Commission.

COST OF SERVICE

<u>Response to Joseph Mancinelli</u>

Q. What major cost-of-service issues does Mr. Mancinelli address?

A. Mr. Mancinelli addresses three major issues:

(1) He performed a detailed examination of the alignment between RMP's inter-jurisdictional classification of costs and the Company's classification of costs used for cost allocation in the Utah jurisdiction, and concluded that there are a number of discrepancies between the classification of costs for inter-jurisdictional purposes relative to class cost allocation purposes. Mr. Mancinelli recommends eliminating most of these differences by making the allocation treatments consistent.

(2) Mr. Mancinelli recommends allocating wind generating plant on a 100 percent energy basis, rather than on a 75 percent demand/25 percent energy basis, as is currently the case; and

(3) Mr. Mancinelli critiques RMP's treatment of the rate mitigation cap in the Company's allocation of costs to customer classes. He concludes that the rate mitigation cap is directly related to production and therefore should be entirely applied to the production function.

Q. What is your response to Mr. Mancinelli's recommendations with respect to the need for consistency between inter-jurisdictional cost allocation and class cost allocation?

A. In general, I support the thrust of Mr. Mancinelli's position. However, I am reserving judgment on specific changes until I have had the opportunity to review RMP's response, as there are likely to be instances in which there are valid reasons for apparent deviations.

I am aware of at least one important example for which this may be the case. Mr. Mancinelli notes that the inter-jurisdictional allocation of seasonal system generation plant costs (CTs and Cholla) differs from how these plant costs are allocated on a class cost-of-service basis. Yet, in the case of seasonal plant costs, the differences stem from changes in inter-jurisdictional allocations that were introduced as part of the MSP Revised Protocol. The class cost allocation of these plants appears to be consistent with how these costs were allocated under the previous Rolled-in methodology.[6] Since, as a practical matter, the Rolled-in method still governs the final allocation of costs to Utah, it is a matter of judgment as to whether the classification of seasonal plant costs for class cost allocation purposes is consistent or inconsistent with the inter-jurisdictional treatment. The answer depends on which inter-jurisdictional method the class cost allocation is being compared to. Since, for purposes of this discussion, both the MSP Revised Protocol and Rolled-in methods are still relevant, the apparent discrepancy between class cost allocation treatment and Revised Protocol treatment may be reasonable.

Q. Do you have any comments on Mr. Mancinelli's recommendation for the allocation of wind generating plant?

A. Yes, I have several observations here. First, the allocation of inter-jurisdictional costs is a comprehensive package that reflects a balancing of interests and the adoption of compromises across states and customer groups. I am concerned that adopting significant changes to allocation factors in isolation, such as Mr. Mancinelli's proposal for wind generation, could potentially unwind the balance of interests achieved in the current inter-jurisdictional allocation approach. Consequently, I object to Mr. Mancinelli's proposed change at this time.

Second, I note that adoption of Mr. Mancinelli's suggested allocation of wind plant would be inconsistent with the interstate allocation of those costs – a result that appears contrary to the thrust of a significant portion of his testimony.

Third, viewed on a standalone basis, I agree with Mr. Mancinelli that wind generation plant can reasonably be viewed as primarily energy-related. However, if, notwithstanding my other objections, the classification of wind generating plant is changed, then I do not believe that classifying it as 100 percent energy-related is appropriate for the Utah jurisdiction. As part of the evaluation presented by PacifiCorp in its 2004 IRP supporting its huge planned investment in wind generation, the Company assigned wind plant a 20 percent capacity value.[7] In general, the classification of embedded costs should be consistent with the decisions made at the time of the investment(s). Consequently, if the classification of wind generating plant is changed from 75 percent demand/25

[6] Holding aside the fact that class allocations use a weighted 12-CP rather than an un-weighted 12-CP.
[7] PacifiCorp – 2004 Integrated Resource Plan, p. 94; also Appendix J, p. 144.

percent energy, then a classification of at least 20 percent demand would be more appropriate than a classification of 100 percent energy.

Fourth, Mr. Mancinelli proposes to change the allocation of costs for wind generating plant, but does not propose corresponding changes in the allocation of benefits from these facilities. Specifically, the allocation of certain benefits, such as renewable energy tax credits and "Green Tag" sales of renewable energy credits, should be consistent with the allocation of wind generating plant costs. If the allocation of costs is changed to reflect a primarily energy weighting, then a corresponding change should also be made to the allocation of the benefits deriving from these investments.

Finally, if the historical approach to cost allocation used in Utah is to be changed for one major cost component such as wind plant, others may reasonably argue that it should also be re-examined with respect to other items. I do not believe that major departures from the allocation methodology currently used in this jurisdiction should be undertaken lightly. Moreover, no significant re-evaluation of class cost responsibility should be undertaken in reliance upon the flawed input data used in this docket.

Q. Do you have any comments on Mr. Mancinelli's discussion of RMP's treatment of the rate mitigation cap in its allocation of costs to customer classes?

A. Yes. I agree with Mr. Mancinelli. His conclusion that the rate mitigation cap is directly related to production and should be entirely applied to the production function is consistent with my own observations and recommendations on this issue.

Response to Paul Chernick (OCS)

Q. On what issues do you wish to respond to Mr. Chernick's testimony?

A. I respond to the following topics in Mr. Chernick's testimony: (1) his proposal to change prospectively the classification of generation plant in RMP cost-of-service studies such that at least 50 percent of generation plant is classified as energy-related; and (2) Mr. Chernick's proposed changes to the determination of distribution cost of service.

Q. What is your response to Mr. Chernick's proposal to change the classification of generation plant in future RMP cost-of-service studies such that at least 50 percent of generation plant is classified as energy-related?

A. I strongly recommend against adoption of Mr. Chernick's proposal. I believe it should be rejected for several reasons.

First, the classification Mr. Chernick proposes is obviously inconsistent with the manner in which inter-jurisdictional costs are allocated to Utah. In this sense, his policy prescription is diametrically opposite that of DPU witness Mr. Mancinelli, who argues for greater conformity between inter-jurisdictional and jurisdictional cost classification. Adoption of Mr. Chernick's proposal would mean that costs would be assigned to Utah on one basis, but allocated across classes on a different basis. This outcome appears to be directly opposite the

Commission's stated intent in its Order in Docket No. 97-035-01, in which the Commission expressly considered the relationship between inter-jurisdictional and class cost allocations and stated: "We also want to insure that these fundamental cost-of-service decisions are applied consistently at the interjurisdictional and class levels."[8] In that same Order, the Commission established a task force to address cost-of-service issues. Its first order of business was to "[r]establish the link between interjurisdictional and class cost allocations."[9]

Q. Does the Commission's Order in Docket No. 97-035-01 expressly provide for an exception to this linkage between interjurisdictional and class cost allocations based on "good and sufficient cause" as asserted by Mr. Chernick?

A. As I am not an attorney, I will not attempt to express an opinion regarding the proper interpretation of the clause referenced by Mr. Chernick. Nor do I wish to suggest that the Commission would not consider taking any action when "good and sufficient cause" is shown. However, I question whether Mr. Chernick is fairly characterizing the Commission's commitment to consistency between inter-jurisdictional and class cost allocations. The clause he cites does not follow immediately after the Commission's discussion of the need for consistency between inter-jurisdictional and class cost allocations, but rather it follows the Commission's discussion of whether functionally unbundling cost of service

[8] Order at 108.
[9] Ibid.

should change the apportionment of class cost responsibility relative to a bundled cost-of-service study.

Mr. Chernick's citation from the Order reads as follows:

> We also want to insure that these fundamental cost-of-service decisions are applied consistently at interjurisdictional and class levels…*unless good and sufficient cause shows otherwise* [emphasis added by Mr. Chernick].

In contrast, the full passage from the Order reads as follows:

> The very basis for task force evaluation of allocations must be that all functionalization, classification, and allocation decisions are correct. This means that the decisions flow from an acceptable characterization of the engineering economics of integrated, single system operation. We expect the task force to assure us that this is so. We also want to insure that these fundamental cost-of-service decisions are applied consistently at interjurisdictional and class levels. The task force therefore should address changes to interjurisdictional allocation method that may be necessary. Moreover, we see no reason why the added step of functionally unbundling cost of service should alter the apportionment of cost of service to classes that results from a properly conducted, but not unbundled, cost-of-service study. In our view, these presumptions must hold unless good and sufficient cause shows otherwise. [Order at 108.]

I will not debate here whether the Commission's apparent expression of its intent ("We also want…") qualifies as a "presumption" in the passage above. But context is important. It is fair to say that I do not view the qualifier at the end of this paragraph as signaling an open invitation to parties to perennially re-challenge the Commission's findings in Docket No. 97-035-01 for the advantage of one's client.

Q. In its Order in Docket No. 97-035-01, did the Commission address the issue of the proper weighting between demand and energy in the allocation of production and transmission costs in Utah?

A. Yes. This is acknowledged by Mr. Chernick, who quotes from the Order. However, Mr. Chernick's quotation omits the express conclusion stated by the Commission on this matter:

> We conclude that twelve monthly coincident peaks, with a 75 percent demand-related and 25 percent energy-related mix, is the appropriate basis for allocating production and transmission costs to classes in the Utah jurisdiction. [Order at 79]

Mr. Chernick goes on to dismiss the 75-25 split as "an arbitrary compromise."

Q. Do you agree with Mr. Chernick's characterization?

A. No. While there are undoubtedly compromises inherent in the determination of the 75-25 split, I do not view it as arbitrary. The Commission determined that the 75-25 split is appropriate for Utah based on the evidence in the record and the recommendation of DPU, among others.

Viewed in context, prior to the PacifiCorp merger, Utah had classified generation and transmission plant as 100 percent demand-related, and the Commission adopted the 75-25 split as part of a consensus-building effort with the other PacifiCorp states. The shift from 100 percent demand-related to 75-25 significantly increases the costs allocated to high load-factor classes, such as Schedule 9. However, this cost shift was accompanied by a presumed long-term benefit associated with the newly-merged system. No such offsetting benefit is envisioned with Mr. Chernick's proposal to further shift costs to higher-load factor customer classes.

In the 97-035-01 docket, when the Large Customer Group (predecessor to the UAE Intervention Group) argued for a return to an allocation based on 100 percent demand, the Commission ruled in favor of the 75-25 split and emphasized the importance of consistency between inter-jurisdictional and class cost allocations (as discussed above). Now Mr. Chernick recommends that this decision be overturned and consistency between inter-jurisdictional and class cost allocations be ignored.

Q. Do you wish to respond to Mr. Chernick's argument that at least 50 percent of generation plant is energy-related?

A. Yes. Mr. Chernick is seeking to have RMP's existing coal fleet classified as at least 50 percent energy-related, based on the argument that the true cost of capacity is represented by a natural gas peaking plant, and that fixed costs above that amount are incurred for energy-related purposes. In my view, the application of this argument to RMP's coal fleet is an exercise in revisionist history.

RMP's coal fleet came on line between 1954 and 1979. Prior to the repeal of the Power Plant and Industrial Fuel Use Act in 1987, electric utilities *could not* just as easily install combustion turbines 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. In the period during which much of RMP's coal fleet was built, a prudent utility seeking to add reliable capacity needed to plan for a plant that did not rely on natural gas. The most feasible capacity option at that time was coal, particularly in the intermountain west, where coal supplies are abundant. Given the conditions under which RMP acquired its coal fleet, the production plant costs of these units can only reasonably be viewed as primarily capacity-related.

This perspective is reinforced by the cost allocation principles that were applicable in Utah when the coal fleet was fully assembled: the costs were classified as 100 percent demand. This classification accurately reflects the manner in which capacity needs were met in Utah. To now re-classify these coal plant costs as 50 percent energy, some thirty-plus years after they were built, is inappropriate, as it does not reflect conditions at the time the investments were made.

It is particularly ironic that the customer classes most responsible for the growth in demand in Utah over the past decade, and who are chiefly responsible for placing continued upward pressure on demand-related costs, would be the primary beneficiaries of the cost-shifting that would result from Mr. Chernick's proposed revisionism.

Q. Do you believe that Mr. Chernick's references to ISO capacity prices provide useful guidance for determining the demand/energy split for class cost allocation purposes in Utah?

A. No. The ISO prices referenced by Mr. Chernick are for wholesale markets and are not meaningful for the purpose of allocating costs among retail customers taking service at cost-based rates. Generally, wholesale power is sold in flat-load blocks, whereas retail service requires shaping, the cost of which is unique to each retail customer class. More fundamentally, the allocation of fixed plant costs in Utah is concerned with fairly apportioning embedded cost responsibility for facilities that are acquired to meet retail load projections by an entity that has an obligation to serve. It is a fundamentally different exercise than structuring a wholesale power market.

Moreover, although Mr. Chernick relies on wholesale market information to support his case, he makes no attempt to price capacity at current market prices in his cost-of-service proposal, but merely uses this information to derive ratios that would be applied to embedded costs. This approach is assured to understate the value of capacity in setting rates, distorting price signals to customers.

Q. Do you have any other comments on the Mr. Chernick's proposed use of the "peaker method?"

A. Yes. The peaker method deems the lowest-cost capacity option to be the "true" cost of demand, and imputes all capacity costs above that amount to energy, on the grounds that any additional capacity expenditure is incurred to reduce energy costs. While this argument produces convenient results for parties that wish to shift costs to higher-load-factor customer classes, its premise does not hold up well upon closer scrutiny. Implicit in this argument is the assumption that the unit energy cost of the peaker plant represents the energy cost avoided when a baseload unit is built. But if the relatively-poor energy efficiency and operating characteristics of the peaker plant limit its application in real-world utility planning, does it really represent a meaningful benchmark for energy savings when a peaker is avoided and a baseload plant is built instead? If not, then why should it be accepted as representing the "true" cost of capacity? To push the theoretical argument further, if a technology existed that could generate power at a very low capital cost, but a prohibitively high energy cost, such that it would never actually be commercially installed, would the "true" cost of demand really fall to near zero simply because such a plant was theoretically possible to construct? According to the peaker method, the answer would be yes. I disagree that an unrealistic option should set the price of demand in determining class cost responsibility. And to the extent that peaking plants do not represent a realistic option for meeting more than a small portion of a utility's capacity needs, the "peaker method" should not be employed for cost allocation purposes.

It is clear that equitable resolution of this issue requires the exercise of reasoned judgment to appropriately balance the cost causative elements of the jointly-supplied products of capacity and energy. This judgment has already been appropriately exercised in the previous decisions of the Commission to adopt and retain the 75 percent demand, 25 percent energy classification. I recommend that the Commission continue to uphold this apportionment.

Q. Mr. Chernick also proposes to classify wind generating plant as at least 50 percent energy. What is your response to that proposal?

A. I oppose this change for the reasons discussed in my response to Mr. Mancinelli's proposal to change the classification of wind generating plants, discussed above.

Q. Do you have any comments regarding Mr. Chernick's proposals for modifying distribution cost of service?

A. Yes. Mr. Chernick makes a number of proposals for modifying distribution cost of service in a manner that would produce more favorable results for Residential customers, such as adjusting the cost allocation for service drops to recognize multiple occupancy housing units. Taken in isolation, such adjustments may be reasonable. However, before adopting these changes, the Commission should consider the broader perspective of how distribution cost of service is determined in Utah. The current approach is extremely favorable to Residential customers, in that it allocates the cost of distribution facilities such as poles, conductors, and transformers exclusively on the basis of demand, without considering that these facilities are installed to deliver service to customer premises, and consequently, should be allocated in part on a customer-related basis.

This principle is well recognized in the Electric Utility Cost Allocation Manual published by NARUC, which states: "The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system."[10] A well-designed and fair distribution cost-of-service study should take these aspects of cost causation into account. As these aspects are <u>not</u> taken into account in Utah for poles, conductors, and transformers, the cost of distribution service allocated to the Residential class is artificially suppressed.

Mr. Chernick's recommendations for modifying distribution cost-of-service amount to "fine-tuning" an analysis that is already fundamentally biased in favor of the beneficiaries of the fine-tuning. If the Commission is disposed to modify RMP's methodology for determining distribution cost of service, then I respectfully suggest that a more comprehensive examination of fundamental cost causation should be undertaken.

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[10] NARUC Electric Utility Cost Allocation Manual, 1992, p. 90.

WIND INTEGRATION COSTS

Q. What issues do you wish to address with respect to wind integration costs in your rebuttal testimony?

A. I addressed wind integration costs in my direct testimony. In this rebuttal testimony, I wish to place my direct testimony on this topic into context relative to the direct testimony on this subject presented by OCS witness Philip Hayet and DPU witness William A. Powell.

Q. Please proceed. What are your comments concerning Mr. Hayet's testimony?

A. In his direct testimony, Mr. Hayet correctly noted that the final approved BPA charges for wind integration service are lower than the rates projected by RMP in its direct filing. Consequently, any final adjustment adopted by the Commission for BPA wind integration charges should be in addition to the wind integration adjustment I am recommending.

Q. What are your comments concerning Dr. Powell's testimony?

A. Dr. Powell objects to RMP's calculation of intra-hour wind integration costs based on his analysis of the statistical validity of the Company's calculations. Based on his review, Dr. Powell recommends disallowing the Company's proposed intra-hour wind integration expense. In essence, this is a "burden of proof" argument. I take no position on the merit of this argument, except to agree that RMP has a substantial burden in defending its proposal to dramatically increase its charges to customers for wind integration.

From a conceptual standpoint, I view intra-hour wind integration costs for "regulating up" to be a valid expense to be recovered from ratepayers. As stated in my direct testimony, RMP's proposed recovery of these costs should be adjusted to remove costs associated with "regulating down." Based on Dr. Powell's testimony, to the extent that RMP has not met its burden of proof in demonstrating its intra-hour wind integration costs, a further adjustment may be warranted. At the same time, my recommendation for treatment of inter-hour wind integration costs is unchanged from my direct testimony: I continue to recommend that RMP's wind integration charges be reduced by $2.08/MWh to remove the cost of assumed transactional losses for performing inter-hour wind integration.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.