BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	)))	Docket No. 6690-UR-122

REBUTTAL TESTIMONY OF JONATHAN WALLACH ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN

September 16, 2013

I. Introduction

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Are you the same Jonathan F. Wallach that filed direct testimony in this proceeding?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of CUB.

Q: What is the purpose of your rebuttal testimony?

A: This rebuttal testimony describes my proposal for allocating to customer classes the Commission staff audit forecast of the 2014 test year electric revenue deficiency. This proposal is based on the results of Commission staff's electric cost of service studies, as described in the pre-filed direct testimony of Corey S.J. Singletary.

In addition, I propose specific rate designs for the residential and small C&I electric rate classes, based on the recommendations in my direct testimony with regard to customer charges.[1]

Finally, this rebuttal testimony responds to the proposals by Robert R. Stephens, on behalf of the Wisconsin Industrial Energy Group (WIEG), to: (1) allocate demand-related production plant costs on the basis of each customer class's contribution to the average of the four summer monthly peaks; and (2) allocate single-phase primary voltage distribution costs solely to secondary voltage customers.

II. Cost Allocation and Rate Design

Q: Please describe Commission staff's cost of service analysis.

A: According to Mr. Singletary, Commission staff conducted four cost of service studies based on the Commission staff audit forecast of 2014 test year revenue requirements. These four studies differ with respect to the methods used to classify production and distribution plant costs, as well as with respect to the treatment of interruptible credits:

- The "WPSC Model" adopts the Company's approach for classifying production and distribution plant costs. As I discussed in my direct testimony, the Company classifies all production plant costs as demand-related and classifies distribution plant costs as customer- or demand-related on the basis of a minimum-system analysis. The WPSC Model also

[1] My recommendation for the design of residential and small C&I rates presumes that the Commission rejects the Company's proposal to extend the RSM. In that regard, I note that Commission staff witness John E. Feit offers a well-reasoned argument for terminating the RSM in his pre-filed direct testimony.

adopts the Company's approach of allocating demand-related production plant costs on the basis of class load net of interruptible load.

- The "Capacity Model" modifies the treatment of interruptible load in the WPSC Model. Specifically, the Capacity Model allocates demand-related production plant costs on the basis of gross class load, but explicitly credits interruptible load at Mr. Singletary's estimate of the avoided cost of capacity.
- The "Time-of-Use Model" modifies the Capacity Model by classifying 40% of production plant costs as demand-related and the remaining 60% as energy-related. This demand/energy split is derived from the results of an Equivalent Peaker analysis conducted by Mr. Singletary.
- The "Location Model" modifies the Time-of-Use Model by classifying all distribution plant costs, other than for meters and services, as demand-related.

Q: Are any of these studies more appropriate than the others?

A: Yes. Of the four studies, the Location Model classifies and allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs.

As I discussed in my direct testimony, the Equivalent Peaker method classifies production plant costs in a manner that reasonably reflects cost causation. Based on the results of my Equivalent Peaker analysis (described in my direct testimony), Mr. Singletary's 40%/60% demand/energy split appears reasonable.

Likewise, and as I also discussed in my direct testimony, the approach used in the Location Model for classifying distribution plant costs more-reasonably reflects cost causation than the minimum-system approach used by WPSC.[2]

Q: Please describe the results of the Location Model.

A: Table 1 provides a summary of the results of the Location Model, as reported in Schedule 1 of Ex.-PSC-Singletary-1. As indicated in Table 1, based on Commission staff's audit, the revenue deficiency for the 2014 test year is about $9.29 million, or about 0.96% of 2014 test year electric revenues under current rates. Given that overall deficiency, the Location Model shows a revenue *excess* of about $29.65 million for residential and small C&I customers. This revenue excess represents about 6.11% of 2014 test year revenues under current rates for residential and small C&I customers.[3]

Table 1: Location Model Results

	Current Revenues	Revenue Increase	Percent Increase
Residential and Small C&I	$485,227,045	($29,654,557)	-6.11%
12,500-25,000 kWh	$36,712,371	($6,005,816)	-16.36%
Medium C&I	$206,663,686	$9,811,444	4.75%
Large C&I	$223,575,466	$39,430,690	17.64%
Lighting & Misc.	$13,712,572	($4,308,464)	-31.42%
Total System	$965,891,140	$9,292,263	0.96%

[2] According to a study by the Regulatory Assistance Project, the method used in the Location Model to classify distribution plant costs is employed in more than thirty states. See Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, December, 2000, p. 30.

[3] In other words, residential and small C&I rates would need to be reduced on average by 6.11% to eliminate excess recovery of $29.65 million in the 2014 test year.

Q: Based on the results of the Location Model, how do you propose to allocate the 2014 test year revenue deficiency?

A: I provide my proposed revenue allocation for each customer class in Table 2 and for each electric rate class in Ex.-CUB-Wallach-2. As can be seen by comparing Tables 1 and 2, I propose to hold revenues essentially constant for the residential and small C&I customer class (as well as for the 12,500-25,000 kWh and lighting classes), even though substantial revenue reductions would be justified by the results of the Location Model. On the other hand, I propose a substantially smaller revenue increase for the large C&I class than would be warranted from a cost-causation perspective.

Table 2: Recommended Revenue Allocation

	Current Revenues	Revenue Increase	Percent Increase
Residential and Small C&I	$485,227,045	($15,357)	0.00%
12,500-25,000 kWh	$36,712,371	$1,459	0.00%
Medium C&I	$206,663,686	$4,133,274	2.00%
Large C&I	$223,575,466	$5,172,884	2.31%
Lighting & Misc.	$13,712,572	$0	0.00%
Total System	$965,891,140	$9,292,263	0.96%

Q: How would you recommend that any changes by the Commission to the Commission staff audit revenue requirements be allocated to customer classes?

A: I would continue to recommend that the Commission staff audit revenue deficiency be allocated as shown in Table 2, above. I would then recommend that the total-system *difference* between the Commission's revenue requirements and the Commission staff audit revenue requirements be allocated to customer

classes in equal proportion, such that all customer classes would experience an equal percentage change in revenues due to the difference between the Commission's and the Commission staff audit revenue requirements.

For example, as indicated in Table 3, if the Commission were to increase the Commission staff audit revenue deficiency by $10 million, that increase would amount to a 1.03% increase in the Commission staff audit revenue requirements. In this case, I would recommend that the Commission staff audit revenue deficiency of $9.29 million be allocated as recommended in Table 2, above. I would further recommend the Commission's additional $10 million revenue deficiency be allocated to customer classes such that each class's revenues (after my recommended allocation of the Commission staff audit revenue deficiency) increase by a uniform 1.03%.

Table 3: Recommended Allocation of Hypothetical Commission Additional Revenue

	Current Revenues	Audit Revenue Increase	Audit Revenues	Commission Increase over Audit Revenues	Percent Increase over Audit	Total Increase over Current Revenues
Residential and Small C&I	$485,227,045	($15,357)	$485,211,687	$4,975,594	1.03%	1.02%
12,500-25,000 kWh	$36,712,371	$1,459	$36,713,833	$376,481	1.03%	1.03%
Medium C&I	$206,663,686	$4,133,274	$210,796,963	$2,161,614	1.03%	3.05%
Large C&I	$223,575,466	$5,172,884	$228,748,349	$2,345,696	1.03%	3.36%
Lighting & Misc.	$13,712,572	$0	$13,712,572	$140,615	1.03%	1.03%
Total System	$965,891,140	$9,292,263	$975,183,403	$10,000,000	1.03%	2.00%

Q: What do you recommend with regard to the design of residential and small C&I rates?

A: I provide my recommended rate designs for the residential and small C&I rate classes in Ex.-CUB-Wallach-3. These rates reflect the customer charges that I

recommended in my direct testimony. These recommended customer charges, which presume that the RSM is not extended, are shown in Table 4.

Table 4. Proposed Monthly Customer Charges with RSM Termination

	Current Charge	Proposed Charge	Percent Change
Rg-1, 3, 5 Single Phase	$5.70	$8.40	47.4%
Rg-2, 4, 6 Single Phase	$7.00	$8.40	20.0%
Rg-1, 3, 5 Three Phase	$9.70	$10.25	5.7%
Rg-2, 4, 6 Three Phase	$11.00	$10.25	(6.8%)
Cg-1, 3 Single Phase	$7.25	$8.50	17.2%
Cg-2, 4 Single Phase	$8.50	$8.50	0.0%
Cg-1, 3 Three Phase	$10.25	$10.25	0.0%
Cg-2, 4 Three Phase	$11.50	$10.25	(10.9%)

With customer charges set at these recommended levels, I then reduced current energy rates for all of the individual rate classes by a uniform percentage in order to achieve my recommended revenue allocation for the residential and small C&I classes as a whole (as shown in Table 2, above.)[4]

III. Response to Mr. Stephens

Q: What does WIEG witness Mr. Stephens propose with regard to the allocation of demand-related production plant costs?

A: In both the Company's and Commission staff's cost of service studies, demand-related production plant costs are allocated to customer classes based on each

[4] I describe above a procedure for allocating to customer classes any modification to the Commission staff audit revenue requirement approved by the Commission. To the extent that the revenue allocation for the residential and small C&I classes pursuant to this procedure is different than shown in Table 2, above, I recommend modifying the uniform percentage factor applied to current energy rates in order to achieve the modified revenue allocation for the residential and small C&I classes.

class's contribution to the average of the twelve monthly peaks (12CP). Mr. Stephens proposes instead that demand-related production plant costs be allocated based on each class's contribution to the average of the monthly peaks for the four summer months (4CP).

Q: Why does Mr. Stephens recommend allocating demand-related production plant costs using a 4CP allocator?

A: Mr. Stephen first argues generally that investments in production plant are driven by "only the hourly demands that are reasonably close to the annual system peak," because "it is only during the highest system load hours that production capacity is most likely to be fully utilized."[5] He then asserts that it is more appropriate to use a 4CP rather than a 12CP allocator, since the peaks for the four summer months fall within a reasonable range of the annual system peak, while the peaks for the remaining eight months do not.

Q: Are production plant costs incurred solely for the purposes of meeting demand in the highest-load hours, as Mr. Stephens contends?

A: No. As I discussed in my direct testimony, under typical generation expansion planning practice, plant investment is driven by both reliability requirements and system energy requirements, with the overall goal of meeting both peak and energy requirements at lowest total cost. System planners would likely invest solely in peaking capacity if plant investment were driven solely by reliability requirements, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. However, the Company has also invested in baseload and intermediate capacity, even though these units have higher fixed costs than peaking capacity, in order to minimize

[5] Direct-WIEG-Stephens-13, ll. 23-25 (PSC REF#: 190109).

the total cost of meeting an increase in energy requirements.[6] In other words, investments in baseload or intermediate capacity are driven by demand in all hours of the year, not just those in the highest-load hours.

Q: Are investments in peaking plant driven solely by monthly peaks during the summer?

A: No. Peak demands during non-summer months also contribute to annual loss of load probability (LOLP) and thus system reserve requirements. For example, the scheduling of plant maintenance during low-demand shoulder months can reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLP and reserve requirements. Consequently, peak demands in non-summer months also contribute to the need for investments in demand-related production plant.

Q: What do you conclude from your review of Mr. Stephens's proposal for allocating demand-related production plant costs?

A: Mr. Stephens has failed to offer a reasonable basis for his proposal. The Commission should therefore reject his recommendation to allocate demand-related production plant costs using a 4CP allocator.

Q: What does Mr. Stephens propose with regard to the allocation of single-phase primary voltage distribution plant costs?

A: Mr. Stephens argues that all such costs should be allocated to secondary voltage customers, since primary voltage customers are not served from the single-phase portion of primary networks and instead rely solely on three-phase service.

[6] As I argued in my direct testimony, from a cost-causation perspective, the fixed costs incurred for baseload or intermediate capacity over and above those incurred for peaking capacity are appropriately classified as energy-related, since these additional fixed costs are incurred to meet energy requirements at lowest total cost.

Consequently, Mr. Stephens proposes that distribution plant costs associated with the three-phase portion of the primary network be allocated among all primary and secondary rate classes, and that those costs associated with the single-phase portion of the primary network be allocated among only the secondary rate classes.

Q: Does Mr. Stephens's proposal allocate primary voltage distribution plant costs in a manner that reasonably reflects cost causation?

A: No. To the contrary, Mr. Stephens's proposal amounts to cherry picking, since he wants primary voltage customers to pay for single-phase costs in proportion to their minimal reliance on the single-phase system, but not to pay for three-phase costs in proportion to their relatively heavy use of the three-phase system.

Mr. Stephens proposes to allocate single-phase primary costs to primary voltage classes not on the basis of those classes' contribution to total system demand or total number of customers, but on the extent to which those classes make use of the single-phase system relative to secondary voltage customers (i.e., zero). In essence, Mr. Stephens argues that allocating single-phase primary cost on the basis of demand or number of customers overstates primary customers' contribution to the total cost of the single-phase system.

However, Mr. Stephens does not propose the same allocation scheme for three-phase primary costs, even though primary customers likely make much greater use of the three-phase system than secondary customers. Instead, under Mr. Stephens's proposal, three-phase primary costs would continue to be allocated to primary voltage customers on the basis of their contributions to total system demand or total number of customers. By Mr. Stephens's own logic, the resulting allocation would *understate* primary customers' contribution to the

total cost of the three-phase system and would thus be unreasonable from a cost-causation perspective.

Q: What do you conclude with regard to Mr. Stephens's proposal for allocating single-phase primary voltage distribution plant costs?

A: Mr. Stephens's proposal is not consistent with cost-causation principles. The Commission should therefore reject his recommendation to allocate all single-phase primary voltage distribution plant costs to secondary voltage customers.

Q: Does this complete your rebuttal testimony?

A: Yes.