BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, to Conduct a Biennial Review of Costs and Rates – Test Year 2015	))))	Docket No. 05-UR-107

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

September 12, 2014

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 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: In your direct testimony you reserved the ability to supplement your recommendation regarding WEPCO's proposed RTMP baseline extension based on information provided in Commission staff's RTMP analysis. Have you reviewed the analysis provided in the pre-filed direct testimony of Corey S.J. Singletary?

A: Yes. There is nothing in Commission staff's analysis that would lead me to revise my recommendation that the original baselines not be extended for existing contracts.

Q: What is the purpose of your rebuttal testimony?

A: This rebuttal testimony describes my proposal for allocating to customer classes the settlement revenue requirements for the 2015 and 2016 test years.[1] 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 Mr. Singletary. I also rely on Commission staff's allocation of the fuel cost deferral, CSAPR amortization, and biomass tax grant credits, as described in the pre-filed direct testimony of Jerry Albrecht.

In addition, I propose specific rate designs for the residential and small C&I electric rate classes, based on the recommendation in my direct testimony that there be no change to residential and small C&I facilities charges.

Finally, this rebuttal testimony responds to the recommendations by WIEG witness Richard A. Baudino to: (1) classify 100% of production plant costs as demand-related; and (2) allocate demand-related production plant costs using the 4CP allocator.

[1] "Settlement revenue requirements" refers to the results of discussions as described by witness Candice C. Spanjar at Direct-PSC-Spanjar-2, line 17 through Direct-PSC-Spanjar-4, line 10. This is distinct from the settlement agreement between WIEG and WEPCO as identified in my direct testimony and referred to in this testimony as the "WIEG/WEPCO settlement agreement."

II. Cost Allocation and Rate Design

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

A: At the request of Commission staff, WEPCO conducted five cost of service studies based on the settlement revenue requirements for the 2015 and 2016 test years. According to Commission staff witness Mr. Singletary, these five studies differ with respect to the methods used to classify and allocate production and distribution plant costs:

- The "Adjusted Base Case COSS" adopts the approach for classifying and allocating production and distribution plant costs adopted by the Company in the WEPCO COSS pursuant to the WIEG/WEPCO settlement agreement. As I discussed in my direct testimony, the WEPCO COSS classifies production plant costs as 75% demand-related and 25% energy-related, and allocates demand-related production plant costs using the 4CP allocator. In addition, the WEPCO COSS classifies distribution plant costs as customer- or demand-related on the basis of a minimum distribution system analysis.
- The "Scenario 1 COSS" modifies the classification of distribution plant costs in the Adjusted Base Case COSS by adopting the demand-related and customer-related classification percentages used in Docket No. 05-UR-106.[2]

[2] According to Mr. Singletary, the Company used ten years of historical data to develop its minimum distribution system classifications in this proceeding, rather than the thirty years of data used in Docket No. 05-UR-106. Commission staff requested the Scenario 1 COSS "in order to illustrate the effect of the change [in historical data period] on the class COSS analysis." (Direct-PSC-Singletary-4, ll. 21-22) However, Mr. Singletary does not appear to support adoption of the Docket No. 05-UR-106 classifications in this proceeding.

- The "Scenario 2 COSS" modifies the Adjusted Base Case COSS by using the 12CP allocator rather than the 4CP allocator to allocate demand-related production plant costs.
- The "Scenario 3 COSS" modifies the Scenario 2 COSS by classifying 60% of production plant costs as demand-related and the remaining 40% as energy-related. In addition, the Scenario 3 COSS classifies non-fuel production O&M costs as 10% demand-related and 90% energy-related. These demand/energy splits are based on the results of Commission staff's Equivalent Peaker analysis.
- The "Scenario 4 COSS" modifies the Scenario 3 COSS by classifying all distribution plant costs, other than for meters and services, as demand-related.

Q: Please describe the results of the five Commission staff cost of service studies.

A: According to Mr. Singletary, the settlement agreement base revenue deficiency (i.e., excluding the fuel cost deferral, CSAPR amortization, and biomass tax grant credits) is about $71.1 million for the 2015 and 2016 test years, or about 2.5% of revenues under current rates.[3] For each of the five cost of service studies, Table 1 shows the allocation of this overall deficiency to each of the major customer classes, expressed as a percentage of revenues under current rates for each class.

As indicated in Table 1, the Adjusted Base Case COSS – reflecting the classification and allocation methods adopted pursuant to the WIEG/WEPCO

[3] Ex.-PSC-Singletary-1, Schedule 1. The revenue deficiency for the 2015 test year falls to $44.5 million, or 1.5% of revenues under current rates, when the fuel cost deferral, CSAPR amortization, and biomass tax grant credits are included.

settlement agreement – shows a base revenue deficiency for residential and small C&I customers of 5.9%. In contrast, the Scenario 2, Scenario 3, and Scenario 4 cost of service studies show a residential and small C&I revenue deficiency that ranges from 3.8% to 0.9%. On average across the Scenario 2, 3, and 4 studies, the revenue deficiency for residential and small C&I customers is 2.4%.[4]

Table 1: Staff COSS Base Revenue Deficiency (% of Current Revenues)

`	System Average	Small Class	Medium Class	Large Class	Lighting Class
Adjusted Base Case COSS	2.5%	5.9%	-6.5%	0.4%	-24.6%
Scenario 1 COSS	2.5%	6.2%	-6.3%	0.0%	-23.8%
Scenario 2 COSS	2.5%	3.8%	-4.9%	2.2%	-4.4%
Scenario 3 COSS	2.5%	2.6%	-4.9%	3.6%	-1.3%
Scenario 4 COSS	2.5%	0.9%	-1.0%	5.1%	-4.5%

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

A: Of the five studies, the Scenario 4 COSS classifies and allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs because it: (1) appropriately classifies production plant costs based on the results of an Equivalent Peaker analysis; and (2) corrects for the inappropriate use of the minimum distribution system method for classifying distribution plant costs.[5]

[4] The average residential and small C&I deficiency across the Scenario 2, 3, and 4 studies falls to 1.6% when the fuel cost deferral, CSAPR amortization, and biomass tax grant credits are included in revenue requirements for the 2015 test year.

[5] Mr. Singletary believes that the Scenario 3 and 4 cost of service studies "provide the most reasonable … allocation of WEPCO's costs." Direct-PSC-Singletary-12, line 6.

However, for the purposes of allocating the overall revenue deficiency to customer classes and setting rates for the 2015 and 2016 test years, it would be appropriate to consider the results of the Scenario 2, 3, and 4 studies. The range of results from these three studies indicate that it would not be reasonable to increase residential and small C&I rates by more than the system-average increase of 2.5% (before accounting for the fuel cost deferral, CSAPR amortization, and biomass tax grant credits).

Q: Based on the results of Commission staff's cost of service studies, how do you propose to allocate the revenue deficiency for the 2015 and 2016 test years?

A: I provide in Table 2 my proposed allocation of base revenues (i.e., excluding the fuel cost deferral, CSAPR amortization, and biomass tax grant credits) to each customer class. As indicated in Table 2, I propose to increase revenues for the residential and small C&I customer class by the system-average revenue increase. As noted above, my proposal for increasing residential and small C&I revenues is consistent with the range of results from the Scenario 2, 3, and 4 cost of service studies.

Table 2: Recommended Base Revenue Allocation

	Current Revenues	Revenue Increase	Percent Increase
Residential & Small C&I	$1,457,365,565	$35,817,419	2.5%
Medium C&I	$196,963,689	$1,969,637	1.0%
Large C&I	$1,210,599,801	$33,205,116	2.7%
Lighting & Other	$29,693,786	$148,469	0.5%
Total Wisconsin Retail	$2,894,622,841	$71,140,641	2.5%

I provide my proposed revenue allocations inclusive of the fuel cost deferral, CSAPR amortization, and biomass tax grant credits in Ex.-CUB-Wallach-3. I use Commission staff witness Mr. Albrecht's allocation of these credits to customer classes in the 2015 test year. As indicated in Ex.-CUB-Wallach-3, my proposed revenue allocation inclusive of these credits amounts to an average rate increase of 1.7% for residential and small C&I customers in the 2015 test year. Average rates for residential and small C&I customers increase by another 0.8% in the 2016 test year, reflecting the expiration of the credits at the end of 2015.

Q: Are you revising the recommendation in your direct testimony to maintain residential and small C&I facilities charges at current rates in light of the results of Commission staff's cost of service studies?

A: No. To the contrary, the results of Commission staff's cost of service studies confirm my recommendation, because they show that residential and small C&I charges would be *reduced* if such charges were set to recover costs that are appropriately classified as customer-related. Specifically, the results of the Scenario 4 COSS show that the customer-related costs allocated to the residential and small C&I classes amount to $9.04 per month, or about 1% less than the current facilities charge of $9.13 per month.[6]

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

[6] See worksheet 'Scenario 4 Customer Cost Detail' of 'PSCW Staff COSS Scenarios Jul 31 2014.xlsx', provided in PSCW Response to 1-CUB/DR-1 (PSC REF#: 214973).

A: I provide my recommended rate designs for the residential and small C&I rate classes in Ex.-CUB-Wallach-4.[7] These rates reflect my proposal for allocating the settlement agreement revenue deficiency for the 2015 and 2016 test years, as shown in Table 2 and Ex.-CUB-Wallach-3. In addition, these rates reflect my recommendation in direct testimony to maintain residential and small C&I facilities charges at current levels.[8]

III. Response to Mr. Baudino

Q: What does Mr. Baudino propose with regard to the classification and allocation of production plant costs?

A: Mr. Baudino proposes that all production plant costs be classified as demand-related, and that all such demand-related costs be allocated using the 4CP allocator.

Q: What is the basis for Mr. Baudino's proposal that all production plant be classified as demand-related?

A: Mr. Baudino offers two arguments in support of his proposal to classify all production plant costs as demand-related. First, Mr. Baudino argues that only peak loads, and not system energy requirements, drive investments in production plant:

[7] My rate designs assume a uniform percentage increase to base energy charges for all residential and small C&I rate classes. I do not adjust the energy charges for the time-of-use (TOU) rate classes to reflect either the Company's or Commission staff's proposals for redesigning residential and small C&I TOU rates.

[8] Any increase to residential and small C&I revenues allowed by the Commission should be recovered solely through energy charges.

> All production plant costs should be classified as demand-related and allocated to customer classes on the basis of class contribution to system peak demand or, in this case, 4CP. This recognizes the fact that all production plant must be available and on line to meet the peak demand requirements of WEPCO's customers. Excess capacity exists during off-peak periods, indicating that off-peak loads and consumption do not contribute to the need for full production capacity throughout the year.[9]

Second, Mr. Baudino asserts that classifying fixed production costs as energy-related would result in off-peak prices that exceed marginal off-peak energy costs and therefore "discourages the improvement of customer load factors and the use of existing base load and intermediate load plant."[10]

Q: Are production plant costs incurred solely for the purposes of meeting peak demand, as Mr. Baudino 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

[9] Direct-WIEG-Baudino-7, line 22 through Direct-WIEG-Baudino-8, line 4.

[10] Direct-WIEG-Baudino-8, ll. 8-9. Mr. Baudino also argues that energy classification of production plant costs would penalize customers with high load factors, because these customers would incur higher costs than would be the case with demand classification if they were to shift usage to off-peak periods. However, this argument appears to be the same as his second argument that energy classification would drive off-peak prices above marginal energy costs.

than peaking capacity, in order to minimize the total cost of meeting an increase in energy requirements.

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. According to testimony by Company witness Eric A. Rogers in Docket No. 05-UR-106, this is in fact the reason why WEPCO relied on the Equivalent Peaker method to classify production plant costs in that proceeding (as well as in prior rate cases, starting with Docket No. 05-UR-102):

> We used the equivalent peaker method to split production plant costs into demand-related and energy-related components. This is the method that best fits the theory that base load and intermediate load plants are built to provide less expensive energy, as well as providing capacity.[11]

Q: Do you agree that classifying production plant costs as energy-related would dampen customer incentives to improve load factor or reduce peak demand?

A: I do not. The process of classifying and allocating costs has little bearing on whether demand or energy rates provide efficient price signals.

Mr. Baudino's concern is one of rate design, not cost allocation. The cost-allocation process is primarily concerned with the assignment of system costs to customer classes based on cost causation. Once those costs have been allocated to customer classes, the rate-design process attempts to create rate structures that recover those allocated costs while promoting efficient outcomes. In other words, it is the rate-design process, not the cost-allocation

[11] Direct-WEPCO/WG-Rogers-16, ll. 10-13, Docket No. 05-UR-106 (PSC REF #: 164646).

process, that determines whether rates provide efficient price signals and promote economic improvements to load factor or reductions in peak demand.

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

A: Mr. Baudino's argument appears to be that the 4CP allocator is justified because reliability requirements, and thus demand-related production plant costs, are driven solely by peak demands in the four summer months:

> WEPCO is clearly and consistently a summer peaking utility during the months of June through September. The 4CP method captures this relationship and appropriately allocates cost to customers based on how WEPCO's customers actually use the system.[12]

Q: Is this a valid argument?

A: No. As Mr. Rogers acknowledged in his direct testimony in Docket No. 05-UR-106, WEPCO "must plan for capacity in all twelve months of the year."[13] In other words, the Company must maintain an adequate margin of available capacity over demand throughout the year in order to ensure that that the annual loss of load probability (LOLP) does not exceed acceptable levels. For example, the scheduling of plant maintenance during low-demand shoulder months may reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLP and reserve requirements. If so, peak demands in these shoulder months would also contribute to the need for investments in reserve capacity.

[12] Direct-WIEG-Baudino-9, ll. 4-7.

[13] Direct-WEPCO/WG-Rogers-13,line 7, Docket No. 05-UR-106.

Q: What do you conclude from your review of Mr. Baudino's proposal for classifying and allocating production plant costs?

A: Mr. Baudino has failed to offer a reasonable basis for his proposal. The Commission should therefore reject Mr. Baudino's recommendations to classify all production plant costs as demand-related and to allocate such costs using the 4CP allocator. Instead, as I discussed in my direct testimony, WEPCO should classify production plant costs using the Equivalent Peaker method, and should allocate demand-related production plant costs to customer classes using the 12CP allocator.

Q: Does this conclude your rebuttal testimony?

A: Yes.