BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light	)	
Company for Authority to Adjust	)	Docket No. 6680-UR-120
Electric and Natural Gas Rates	)	
For 2017 and 2018 Test Years	)	

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

September 21, 2016

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: My rebuttal testimony responds to direct testimony by:

- Commission staff witness Kate Christensen regarding her adjustments to the Company's cost of service studies to reflect the results of Commission staff's annual fuel audit.

- Kavita Maini, on behalf of Wisconsin Industrial Energy Group (WIEG), regarding the classification and allocation of production and distribution plant costs and in support of the development of market-based rates for industrial customers.
- Daniel Tyson Steadman Cook, on behalf of Clean Wisconsin, regarding his proposal to implement "opt-out" pilots for residential time-of-day and demand rates.

II. Response to Ms. Christensen

Q: Please summarize Commission staff witness Ms. Christensen's direct testimony regarding her adjustments to the Company's cost of service studies.

A: Ms. Christensen adjusted the Company's cost of service studies to reflect the results of Commission staff's annual fuel audit. Specifically, Ms. Christensen increased 2017 and 2018 test year revenue requirements by about $4.4 million to reflect Commission staff's adjustments to monitored fuel costs.[1] This $4.4 million increase was allocated to rate classes in proportion to each class's energy sales. The results of the adjusted studies are shown at Direct-PSC-Christensen-4.

Q: Did Ms. Christensen reasonably allocate the $4.4 million increase in test year revenue requirements resulting from Commission staff's adjustments to monitored fuel costs?

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[1] Ms. Christensen's adjustments are contained in 'COSS Summary.xlsx', which was provided in Commission staff's response to Data Request CUB-1 on September 12, 2016. The $4.4 million increase in 2017 and 2018 test year revenue requirements was derived by Commission staff witness Mary Kettle, as shown in Schedule 1 of Ex.-PSC-Kettle-1.

A: Yes. Ms. Christensen's allocation of the $4.4 million fuel-related increase is consistent with the allocation of fuel costs in the Company's cost of service studies.

Q: Based on the results of the adjusted cost of service studies, how would you allocate test year revenue requirements?

A: Based on the directional results of the adjusted studies, I recommend that 2017 test year revenues be allocated to customer classes as shown in Table 1. I developed this allocation with the goal of narrowing the difference for all classes between the allocated revenue increase and the system average increase in order to avoid rate shock for any one class.

Table 1: Adjusted COSS-Based Allocation of 2017 Test Year Revenues

	Current Revenue	Proposed Revenue	Revenue Increase	Percent Increase
Residential	414,738,377	429,114,310	14,375,933	3.5%
General Service	189,828,118	192,706,478	2,878,360	1.5%
Commercial	115,617,604	115,617,604	-	0.0%
Industrial	409,452,293	409,452,293	-	0.0%
Lighting	8,285,992	8,285,992	-	0.0%
Total System	1,137,922,385	1,155,176,678	17,254,293	1.5%

I further recommend that the rates established to recover allocated 2017 test year revenues remain fixed for the 2018 test year as well. Based on the Company's forecast of class billing determinants, fixing rates at 2017 test year levels would allow forecasted 2018 test year revenue requirements to be recovered from each customer class in the same proportion as my recommended allocation of forecasted 2017 test year revenue requirements.

III. Response to Ms. Maini

A. Classification and Allocation of Production Plant Costs

Q: What does WIEG witness Ms. Maini propose with regard to the classification and allocation of production plant costs?

A: Ms. Maini proposes that all production plant costs be classified as demand-related, and that all such demand-related costs be allocated using a 3CP allocator.

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

A: Ms. Maini offers three arguments in support of her proposal to classify all production plant costs as demand-related. First, Ms. Maini argues that only peak loads, and not system energy requirements, drive investments in production plant.[2] Second, Ms. Maini argues that all production plant costs should be classified as demand-related, because such costs, once incurred, do not vary with energy usage.[3] Finally, Ms. Maini argues that classifying a portion of production plant costs as energy-related distorts price signals because costs classified as energy-related would be shifted from the demand charge to the off-peak energy charge.[4]

I respond to each of Ms. Maini's arguments in turn.

Q: Are production plant costs incurred solely for the purposes of meeting peak demand, as Ms. Maini contends?

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[2] Direct-WIEG-Maini-15.

[3] *Id.*

[4] Direct-WIEG-Maini-19.

A: No. If, as Ms. Maini claims, WPL added production plant solely for the purposes of meeting reserve requirements, then the Company's resource portfolio would consist solely of peaking generation since peaking units would be the cheapest option for meeting an increase in planning reserve requirements. In reality, WPL has invested in not just peaking plant, but also more-expensive baseload generation in order to minimize the cost of meeting system energy requirements.

From a cost-causation perspective, the additional plant cost incurred for a baseload plant over that for a peaking plant is appropriately classified as energy-related because this additional cost is incurred to meet energy requirements at lowest total cost.

Q: Should cost classification depend on whether production plant costs vary with energy usage once such costs are ratebased, as Ms. Maini contends?

A: No. From a cost-causation perspective, the relevant consideration for classifying production plant costs is not the extent to which such costs vary with energy usage once those costs have been placed in ratebase, but the extent to which the Company's investments in production plant were driven by increases in planning-reserve or energy requirements. From this perspective, it would be unreasonable to classify all production plant costs as demand-related, since investments in baseload and cycling plant were driven by the need to meet both reliability and energy requirements.

Q: Do you agree with Ms. Maini that price signals would be distorted if a portion of production plant costs were classified as energy-related?

A: I do not. To the contrary, energy-related production plant costs are appropriately recovered through energy charges since, as discussed above, energy usage drives investment in baseload plant and thus causes utilities to incur production plant costs in excess of amounts that would be incurred for equivalent peaking capacity. This excess spending should therefore be classified as energy-related and recovered through energy charges.

Q: Why does Ms. Maini recommend allocating demand-related production plant costs using a 3CP allocator?

A: Ms. Maini argues that it is appropriate to use a 3CP allocator because the Company's investments in production plant are driven solely by peak demands in the three summer months and because there is excess capacity on the Company's system during the non-summer months which allows WPL to schedule planned maintenance.

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

A: No. Peak demands during non-summer months also contribute to annual loss of load expectation (LOLE) and thus system reserve requirements. Consequently, peak demands in non-summer months also contribute to the need for investments in demand-related production plant.

Ms. Maini mistakes cause for effect with regard to the availability of excess capacity to offset capacity reductions from planned maintenance in non-summer months. The amount of capacity required in excess of summer peak – i.e., the annual reserve margin – is determined in part by the daily contribution to annual LOLE as a result of planned maintenance during the non-summer months. In other words, the MISO reserve requirement is set at that percentage margin over summer peak that ensures that LOLE over the year, including the contribution to LOLE during times of planned maintenance, is less than one day in ten years. Thus, it's not that capacity reserves in excess of summer peak allow for planned maintenance in non-summer months, as Ms. Maini contends.

Instead, it's that the impact of planned maintenance on annual LOLE drives in part the amount of capacity needed in excess of summer peak to maintain system reliability.

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

A: Contrary to Ms. Maini's claim, the Company's investments in production plant are driven by both reliability and energy requirements. Consequently, production plant costs are appropriately classified as both demand- and energy-related.

Moreover, demand-related production plant costs incurred to meet reserve requirements are driven by demand in both summer and non-summer months. The 12CP allocator is therefore a more reasonable measure of each class's contribution to the need for new reserve capacity than the 3CP allocator.

B. Classification of Distribution Plant Costs

Q: Please summarize Ms. Maini's direct testimony with regard to the classification of distribution plant costs.

A: Ms. Maini supports use of the minimum distribution system method for classifying distribution plant costs because:

> … to the extent that the utility incurs a distribution cost simply to connect a customer to its system, regardless of that customer's size, it is appropriate to assign the cost of these minimal facilities to rate schedules on the basis of the number of customers, rather than on the kW demand of the class.[5]

Q: How do you respond to Ms. Maini's argument in favor of the minimum distribution system classification approach?

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[5] Direct-WIEG-Maini-20.

A: The problem with Ms. Maini's argument is that it presumes that WPL incurs costs for poles, conduits, wires, and transformers "simply to connect a customer to its system, regardless of that customer's size." In fact, it is unlikely that the Company would add distribution equipment other than a meter and a service drop just to connect an additional customer with minimal load. Thus, it would not be consistent with cost-causation to classify the costs of distribution equipment other than meters and services as customer-related, as would be the case using the minimum distribution system classification approach.

Instead, as is the case in the Company's Locational COSS, meter and services costs should be classified as customer-related and all other distribution plant costs should be classified as demand-related.

C. Market-Based Rate Options

Q: At Direct-WIEG-Maini-5, Ms. Maini indicates that WIEG is interested in working with WPL and Commission staff to develop market-based rate options for industrial customers. How do you respond?

A: It is critical that such rate options be designed to avoid cost-shifting from the industrial class to other customer classes. It would be wholly inappropriate to implement a market-based rate option that allows industrial customers to evade responsibility for sunk production plant costs incurred by WPL to serve such customers and then pass those costs on to other customer classes.

IV. Response to Mr. Cook

Q: At Direct-Clean Wisconsin-Cook-9, Clean Wisconsin witness Mr. Cook recommends that WPL consider implementing a pilot program where

randomly selected residential customers are moved to time of day rates on an opt-out basis. How do you respond?

A: I want to note that CUB generally supports efforts to improve the efficacy and increase customer acceptance of time of day (TOD) rates. However, CUB has a number of concerns regarding Mr. Cook's specific suggestion in this case that residential customers be moved to TOD rates without their consent and then be required to actively opt-out in order to be placed back on standard rates. In particular, CUB is concerned about potential adverse impacts on low-income or other vulnerable residents in multi-family buildings who may not be able to modify usage patterns in order to avoid high on-peak prices.

If relatively few customers have chosen to opt in to the current voluntary TOD rate, the solution should not be to force customers onto the TOD rate and then require them to opt out if they are dissatisfied. Instead, the Commission should direct WPL to identify where and how the current rate structure creates barriers to customer participation and to evaluate design modifications to make the TOD rate more attractive to residential customers.

Q: At Direct-Clean Wisconsin-Cook-18, Clean Wisconsin witness Mr. Cook recommends that WPL consider implementing a pilot program where randomly selected residential customers are moved to demand rates on an opt-out basis. How do you respond?

A: CUB has the same concerns about an opt-out demand rate pilot as it does about an opt-out TOD rate pilot, only more so given concerns (shared by Mr. Cook) that residential customers would have limited ability to control their maximum demands in response to demand charges.

Q: Does this complete your rebuttal testimony?

A: Yes.