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

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

September 25, 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 and rebuttal 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 surrebuttal testimony?

A: This surrebuttal testimony responds to rebuttal testimony filed in this proceeding regarding the following issues:[1]

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[1] I do not respond to the discussion by WPSC and WIEG witnesses regarding Commission staff's treatment of interruptible credits, because I did not explicitly address this issue in my direct or rebuttal testimony. However, in my rebuttal testimony, I rely on the results of Commission

- Extension of the electric and gas RSMs, as discussed by WPSC witness David J. Kyto.
- The Equivalent Peaker method for classifying production plant costs, as discussed by WPSC witness Joylyn C. Hoffman Malueg and WIEG witness Robert R. Stephens.
- The minimum-system method for classifying distribution plant costs, as discussed by Ms. Hoffman Malueg and Mr. Stephens.
- The allocation of single-phase primary voltage distribution costs, as discussed by Ms. Hoffman Malueg.
- Customer charges for residential and small C&I rate classes, as discussed by WPSC witness Russell T. Laursen.

II. Extension of the RSM

Q: What do you recommend with regard to the Company's proposal to extend the RSMs?

A: As I discussed in my direct testimony, I recommend that the Commission reject the Company's proposal to make permanent the pilot RSMs. The pilot RSMs have failed to meet their design objective of permanently aligning the Company's financial interests with its customers' economic interests. In particular, the pilot RSMs have failed to provide incentives to management to continue the gains achieved under the Stipulation by voluntarily investing in energy efficiency programs beyond levels mandated for Focus on Energy

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staff's cost of service modeling as the basis for my proposed allocation of the 2014 test year revenue deficiency, because I consider Commission staff's treatment of interruptible credits to be conceptually sound.

programs or by supporting rate designs that improve price signals for customer conservation.

Q: How does Mr. Kyto respond to your recommendation to terminate the RSMs?

A: Mr. Kyto disputes the basis for my conclusion that the RSMs have failed to permanently align shareholder and ratepayer interests. Specifically, Mr. Kyto contends that WPSC is terminating its voluntary investments in energy efficiency and increasing residential and small C&I customer charges because the Company has fulfilled its obligations under the Stipulation. Thus, according to Mr. Kyto, WPSC is unwilling to continue the gains achieved under the Stipulation not because the RSMs have failed to provide appropriate incentives, but simply because the Company is no longer obligated under the Stipulation to continue to offer tangible benefits to ratepayers.

Q: Is Mr. Kyto's argument reasonable?

A: No. In fact, Mr. Kyto's explanation bolsters my finding that the RSMs have not permanently altered management's incentives to maximize sales. With the RSMs, but without the obligations imposed by the Stipulation, the Company is unwilling to voluntarily invest in energy efficiency programs beyond levels mandated for Focus on Energy programs or to support rate designs that improve price signals for customer conservation. Thus, the only reasonable conclusion would be that the RSMs do not provide incentives to the Company to engage in conservation efforts beyond mandated requirements.

Accordingly, I continue to recommend that the Commission reject the Company's proposal to extend the RSMs.

Q: What did you recommend in your direct testimony in the event that the Commission approves an extension of the RSMs?

A: I recommended the following:

- Limit the extension to three years and require that the Company file annual reports on RSM performance in each year of the extension period.
- Maintain the caps on annual RSM recoveries or credits.
- Approve extension of the RSMs only on the condition that WPSC increase its annual contributions to FOE programs up to 3.5% of residential and commercial electric revenues and 3.0% of residential and commercial gas revenues.
- Generally, maintain customer charges for residential and small commercial rate classes at current levels.
- Reduce the allowed return on equity as recommended by CUB witness Stephen G. Hill to account for reduced risk associated with decoupling.

Q: How does Mr. Kyto respond to your recommendations?

A: Mr. Kyto states that the Company would agree to limit the extension to three years. However, Mr. Kyto gives no indication that WPSC would agree to any of my other proposed conditions.

Q: Would it be reasonable to extend the RSMs without imposing these other conditions?

A: No. As I discussed in my direct testimony, I recommended all of these conditions so that ratepayers would continue to benefit from the gains achieved under the pilot RSMs. Such ratepayer benefits would be lost if the RSMs were extended without these other conditions, leaving only the Company to benefit from the extension of the RSMs.

III. Classification of Production Plant Costs

Q: What do you recommend with regard to the classification of production plant costs?

A: I recommend that production plant costs be classified as either demand- or energy-related using the Equivalent Peaker classification method.[2] As I discussed in my direct testimony, the Equivalent Peaker method reflects investment decision-making under typical generation expansion planning practices. Under the Equivalent Peaker approach, investments in peaking plant are classified as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. In contrast, baseload or intermediate plant costs in excess of peaking plant costs (i.e., capitalized energy costs) are classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

Q: How does Ms. Hoffman Malueg respond to your recommendation?

A: Ms. Hoffman Malueg opposes use of the Equivalent Peaker method to classify production plant costs, because "this method does not allocate fixed production costs as a system, and does not take into account required system reserve margins."[3]

Q: Do you agree with Ms. Hoffman Malueg's characterization of the Equivalent Peaker method?

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[2] Commission staff witness Mr. Singletary also recommends use of the Equivalent Peaker method for classifying production plant costs.

[3] Rebuttal-WPSC-Hoffman Malueg-4, ll. 26-27.

A: No. The Equivalent Peaker approach classifies costs consistent with total-system resource planning, which seeks to invest in that mix of baseload, intermediate, and peaking plant that meets both reliability and energy requirements at minimum total-system cost. Thus, contrary to Ms. Hoffman Malueg's characterization, the Equivalent Peaker approach classifies costs from a total-system perspective and in a manner that reflects the fact that costs are incurred to meet both system reserve requirements and energy requirements.

Q: Does Ms. Hoffman Malueg offer any additional comment about the Equivalent Peaker method?

A: Yes. Ms. Hoffman Malueg suggests that if the Equivalent Peaker method is applied to production plant costs, then it should also be applied to variable production expenses so that a portion of those variable costs can be classified as demand-related and allocated on demand.

Q: Is this a reasonable suggestion?

A: No. It would not be appropriate to classify variable production expenses as demand-related, since such costs are driven by energy requirements.[4]

Q: Please summarize WIEG witness Mr. Stephens's discussion of the Equivalent Peaker method.

A: Mr. Stephens believes that the Equivalent Peaker approach is flawed, because:

[4] A possible exception would be contract costs for power purchases, since a portion of those contract payments could be considered demand-related to the extent that contract capacity contributes to meeting planning-reserve requirements. However, all costs for renewable contracts that were acquired for the purposes of meeting renewable portfolio standards (RPS) should be classified as energy-related, since the RPS requirement is driven solely by energy requirements.

> … (1) production plant costs related to intermediate and peaking generating stations are allocated to the classes as if those units had the same construction and operating cost characteristics as baseload units; and (2) no corresponding adjustment is made to the cost of fuel so the costs of the oil, natural gas, and coal that are burned in intermediate and peaker generating stations are again allocated to the classes as if those units were baseload units.[5]

In other words, the Equivalent Peaker method classifies as energy-related all baseload and intermediate plant costs in excess of peaking plant costs, since these capitalized energy costs were incurred to reduce fuel costs (compared to fuel costs for an all-peaker system). As a result, high load factor customers are allocated a greater share of these capitalized energy costs than of demand-related peaking plant costs. However, according to Mr. Stephens, high load factor customers are not allocated a commensurately greater share of the fuel savings associated with these capitalized energy investments. Thus, Mr. Stephens believes that high load factor customers are not credited for the fuel savings associated with capitalized energy investments in proportion to their share of capitalized energy costs.

Q: Is Mr. Stephens's argument valid?

A: No. Mr. Stephens is mistaken in his belief that high load factor customers are not adequately credited for the fuel savings associated with capitalized energy investments. Contrary to Mr. Stephens's belief, the Company's energy allocator – based on load-weighted average marginal energy cost – effectively allocates fuel costs in proportion to each class's contribution to fuel cost in each hour. Thus, a low load factor customer, whose energy consumption is concentrated in the higher-cost on-peak hours, will be allocated more fuel cost than a high load

[5] Rebuttal-WIEG-Stephens-17, ll. 5-11.

factor customer with the same annual consumption. As a result, high load factor customers pay a lower fuel rate than low load factor customers.

On the other hand, Mr. Stephens overlooks the fact that the Company's energy allocator actually allocates *less* capitalized energy cost to high load factor customers than is appropriate from a cost-causation perspective. Just as high load factor customers should be allocated more of the fuel savings associated with capitalized energy investments, they should also be allocated more of the capitalized energy costs that gave rise to these fuel savings. However, as noted above, the Company's energy allocator allocates a greater proportion of capitalized energy costs to a low load factor customer than to a high load factor customer of equal size.

Q: Does Mr. Stephens offer any other comment regarding the Equivalent Peaker method?

A: Yes. In the event that the Commission approves use of the Equivalent Peaker method, Mr. Stephens recommends that demand-related production plant costs be allocated based on each class's contribution to system coincident peak (1CP). Mr. Stephens characterizes the 1CP allocator as a "more 'pure' demand allocator."[6]

Q: Is this proposal reasonable?

A: No. Contrary to Mr. Stephens's characterization, no demand allocator is "more pure" than any other, and the appropriateness of a demand allocator does not vary with the method selected to classify production plant costs. Instead, as I discussed in my rebuttal testimony, demand-related production plant costs should be allocated in proportion to each class's contribution to the need for new

[6] Rebuttal-WIEG-Stephens-21, line 16.

reserve capacity. No matter the method used to classify production plant costs, the 12CP allocator is the most-reasonable measure of each class's contribution to the need for new reserve capacity.

Q: Please summarize your response to the Company's and WIEG's arguments regarding the Equivalent Peaker method.

A: Neither Ms. Hoffman Malueg's nor Mr. Stephens's criticisms of the Equivalent Peaker approach have merit. I therefore continue to recommend that production plant costs be classified using the Equivalent Peaker method.

IV. Classification of Distribution Plant Costs

Q: Please summarize your recommendation regarding the classification of distribution plant costs.

A: As I discussed in my direct testimony, the minimum-system approach used by WPSC to classify distribution plant costs suffers from a number of defects that result in the misclassification of demand-related costs as customer-related. This misclassification, in turn, leads to an over-allocation of distribution plant costs to residential and small C&I customers. I therefore recommend an alternative approach, which classifies meters and services as customer-related and all other distribution plant costs as demand-related.

Q: How does Ms. Hoffman Malueg respond to your criticisms regarding the minimum-system method?

A: Ms. Hoffman Malueg does not address my substantive arguments. Instead, she simply notes that both of the studies I cited in support of my critique of the minimum-system approach (Bonbright and Sterzinger) claim that most jurisdictions relied on the minimum-system method in the 1980s.

Q: Is use of the minimum-system method still as widespread as alleged by Bonbright and Sterzinger?

A: I have not done a comprehensive survey of classification practices in other jurisdictions. However, as I noted in my rebuttal testimony, a study by the Regulatory Assistance Project found that my recommended alternative classification approach was in use in more than thirty states as of the year 2000.[7]

Q: Please summarize Mr. Stephens's discussion of the minimum-system approach.

A: Mr. Stephens cites to the safety standards in the National Electrical Safety Code (NESC) to illustrate the merits of the minimum-system method. For example, he notes that the NESC requires a minimum height for poles regardless of the load on the conductors carried on a pole. Mr. Stephens then concludes that:

> Given that the principal reason to extend the distribution system is to serve additional customers, it is only reasonable to conclude that the costs associated with the NESC, and thus, the [minimum system], vary with the number of customers.[8]

Q: Is Mr. Stephens's conclusion valid?

A: No. The fallacy in Mr. Stephens's argument is that although the NESC safety standards may require a minimum-sized system, the cost of that minimum system does not necessarily vary with the number of customers. For example, if service were extended to a new area using minimum-height poles, the total cost of those poles would likely be the same whether service was being extended to a

[7] This study further notes that, in certain respects, the minimum-system method "seems absurd, since in the absence of any demand no such system would be built at all." See Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, December, 2000, p. 31.

[8] Rebuttal-WIEG-Stephens-24, ll. 1-4.

single industrial customer or to an apartment building with 100 residential customers. If the cost of the minimum system does not vary with the number of customers, it would not be appropriate to allocate such minimum costs to rate classes in proportion to the number of customers in each class.

This discussion illustrates the fundamental problem with the minimum-system approach. Even if one could reasonably estimate the cost of a minimum system to serve the Company's customers, there is no reason to believe that those costs would vary directly with the number of customers. Instead, such costs might vary with such factors as customer density or topography.

Q: Given the problems with the minimum-system method, is there a reasonable alternative method for classifying distribution plant costs?

A: Yes. As I discussed in my direct testimony, a reasonable and reasonably straightforward approach would be to classify meters and services as customer-related and all other distribution plant costs as demand-related. This approach recognizes that the distribution system is sized to meet customer demand and that changes to that system are largely driven by increases in that demand.

V. Allocation of Primary Voltage Distribution Costs

Q: Please summarize Ms. Hoffman Malueg's testimony regarding the allocation of primary voltage distribution costs.

A: Ms. Hoffman Malueg discusses this issue in response to a proposal by Mr. Stephens. In his direct testimony, Mr. Stephens argues that all single-phase primary voltage distribution 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. In response, Ms. Hoffman Malueg asserts that Mr. Stephens's proposal, if done properly, would improve the accuracy of the Company's cost of service study.

Q: Do you agree that Mr. Stephens's allocation proposal more accurately reflects customers' responsibility for primary voltage distribution costs?

A: No. As I discussed in my rebuttal testimony, Mr. Stephens's proposal is inconsistent with cost-causation principles, since it would allocate single-phase costs to primary customers consistent with their minimal reliance on the single-phase system, but would allocate less of the three-phase costs to primary customers than is warranted by their relatively heavy use of the three-phase system.

Given this inconsistency, I continue to recommend that the Commission reject Mr. Stephens's proposal to allocate all single-phase primary voltage distribution plant costs to secondary voltage customers.

VI. Residential and Small C&I Customer Charges

Q: Please summarize your direct testimony regarding the Company's proposal to increase residential and small C&I electric customer charges.

A: In my direct testimony, I concluded that WPSC lacks a reasonable basis for its proposal to increase residential and small C&I customer charges. Specifically, I described how the Company unreasonably relied on the results of its cost of service study as justification for its proposal to dramatically increase customer charges. In addition, I discussed why Company witness Mr. Laursen's claim that the current customer charge "dilutes the price signal" was not valid.

Given the lack of a reasonable basis, I recommended in my direct testimony that the Commission reject certain elements of the Company's proposal and instead approve the customer charges that I proposed.

Q: How does Company witness Mr. Laursen respond to your criticisms of the Company's basis for its proposal to increase customer charges?

A: Instead of responding to my criticisms, Mr. Laursen simply repeats the arguments he made in his direct testimony in support of the Company's proposal.

Q: Are you revising your recommendations in light of Mr. Laursen's rebuttal?

A: No. Mr. Laursen has not offered a substantive rebuttal of my criticisms of the Company's proposal. I therefore continue to recommend that the Commission reject the Company's proposals to: (1) increase residential urban and rural charges to the rate charged to rural customers prior to implementation of the Stipulation; and (2) increase small C&I customer charges to pre-Stipulation levels. Instead, and presuming termination of the RSM for electric service, I recommend that customer charges be set as shown in Table 1.

Table 1. 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%)

Q: Does this complete your surrebuttal testimony?

A: Yes.