BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric	)	
Company for Authority to Change	)	Docket No. 3270-UR-121
Electric and Natural Gas Rates	)	

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

September 9, 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 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 addresses direct testimony by Commission staff witness Jacquelin Madsen regarding the impacts on 2017 test year revenue requirements from proposed changes in the Company's ownership share of the Columbia Energy Center (Columbia) and to the depreciation rates for Columbia.

In addition, this rebuttal testimony responds to the recommendation by Kenneth Lyons on behalf of Airgas Merchant Gases (Airgas) to allocate demand-related production plant costs on the basis of each customer class's contribution to the average of the four summer monthly peaks (4CP).

II. Response to Ms. Madsen

Q: Please summarize Ms. Madsen's direct testimony regarding the revenue requirement impact from proposed changes in Columbia ownership shares and depreciation rates.

A: According to Ms. Madsen, MGE has filed for approval of a reduction in its ownership share of Columbia in Docket No. 5-BS-214. Ms. Madsen estimates that this change in ownership share would reduce 2017 test year revenue requirements by about $725,000.[1]

With regard to Columbia depreciation rates, Ms. Madsen remarks that Wisconsin Power and Light Company has filed for approval of amended depreciation rates in Docket No. 6680-DU-108. Ms. Madsen indicates that 2017 test year revenue requirements would increase by about $2.3 million if the Commission were to approve the amended depreciation rates.[2]

Ms. Madsen also notes that neither of these two revenue requirement impacts were reflected in Commission staff's audit forecast of 2017 test year revenue requirements for this proceeding.

Q: How should these two revenue requirement impacts be reflected in rates?

[1] Direct-PSC-Madsen-9.

[2] Direct-PSC-Madsen-10.

A: If the Commission rules on the proposed change in ownership share in Docket No. 5-BS-214 prior to the Commission's decision in this proceeding, I recommend that the revenue requirement impact of the Commission's decision in Docket No. 5-BS-214 be reflected in 2017 test year rates. Otherwise, I recommend that consideration of the impact of the change in ownership share be deferred to a future proceeding. Likewise, I recommend that the revenue requirement impact of the Commission's decision on the proposed change in depreciation rates be reflected in 2017 test year rates if the Commission rules in Docket No. 6680-DU-108 prior to the Commission's decision in this proceeding or deferred to a future proceeding if not.

Whether reflected in 2017 test year rates in this proceeding or deferred to a future proceeding, I recommend that the revenue requirement impact from either the change in ownership share or the change in deprecation rates be allocated to customer classes in proportion to current revenues.

III. Response to Mr. Lyons

Q: What does Mr. Lyons recommend with regard to the allocation of demand-related production plant costs?

A: Mr. Lyons recommends that demand-related production plant costs be allocated using a 4CP allocator, rather than the 12CP allocator that MGE has traditionally used.

Q: Why does Mr. Lyons argue for using the 4CP allocator?

A: Mr. Lyons believes that allocation on the basis of the annual system peak (1CP) "best reflects the cause of MGE incurring capacity cost."[3] However, in this proceeding, Mr. Lyons supports the 4CP allocator as a reasonable substitute for 1CP because "MGE's four summer month peaks are relatively close."[4]

Q: What is the basis for Mr. Lyons's claim that the 1CP allocator best reflects cost-causation for production plant costs?

A: Mr. Lyons believes that that the NARUC Cost Allocation Manual supports his claim, and cites the following passage from the Cost Allocation Manual as the basis for his belief:

> *If the utility plans its generation capacity additions to serve its demand in the peak hour of the year*, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.[5]

Q: Do you agree that the NARUC Cost Allocation Manual supports Mr. Lyons's claim that the 1CP allocator best reflects cost-causation?

A: No. Mr. Lyons overlooks the fact that the Cost Allocation Manual supports the 1CP allocator only in those cases where a "utility plans its generation capacity additions to serve its demand in the peak hour of the year." The Cost Allocation Manual also states that:

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[3] Direct-Airgas-Lyons-6.

[4] *Id.*

[5] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, p. 39. Emphasis added.

> In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it become apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs….
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> If the utility bases its generation expansion planning on reliability criteria – such as loss of load probability or expected unserved energy – that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs.[6]

Q: Are the Company's reserve capacity requirements determined using the type of reliability criteria cited in the Cost Allocation Manual as justification for relying on an allocator other than a 1CP or 4CP allocator?

A: Yes. Specifically, the Midcontinent Independent System Operator determines the amount of capacity required for planning reserve based on the results of a loss of load probability analysis that considers the contribution in every month of the year of the Company's demand to annual loss of load expectation. Thus, the reliability criteria used to determine the Company's reserve requirements justifies reliance on an allocator other than a 1CP or 4CP allocator and in fact supports use of the 12CP allocator.

Q: Should the Commission adopt Airgas's proposal to rely on the 4CP allocator for allocating demand-related production plant costs?

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[6] *Id.*

A: No. Airgas lacks a reasonable basis for its proposal to allocate demand-related production plant costs using a 4CP allocator. The Company should therefore continue to allocate demand-related production plant costs on the basis of each customer class's contribution to the average of the twelve monthly peaks.

Q: Does this complete your rebuttal testimony?

A: Yes.