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 2013	))))	 Docket No. 05-UR-106

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

September 7, 2012

I. Introduction and Summary

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: Please summarize your professional experience.

A: I have worked as a consultant to the electric-power industry since 1981. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the past thirty years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and management; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Ex.-CUB-Wallach-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have sponsored expert testimony in more than 55 federal, provincial, or state proceedings in the U.S. and Canada. In Wisconsin, I testified in Docket Nos. 6630-CE-302, 3270-UR-117, 4220-UR-117, and 6680-FR-104. I include a detailed list of my previous testimony in Ex.-CUB-Wallach-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Citizens Utility Board of Wisconsin (CUB).

Q: What is the purpose of your testimony?

A: On March 23, 2012, Wisconsin Electric Power Company (WEPCO or "the Company") filed an application to increase electric rates by 3.6% on average across all rate classes in each of the 2013 and 2014 test years and to make various changes to current rate designs. This testimony addresses three aspects of the Company's filing: (1) the methods used in the embedded cost of service study (COSS) to allocate the proposed rate increases to the residential class; (2) the Company's proposal to increase residential facilities charges by 40%; and (3) the Company's proposal to terminate the residential air-conditioning load-control program. All three of these elements are discussed in the pre-filed direct testimony of Company witness Eric A. Rogers.

Q: Please summarize your findings and recommendations.

A: The Company conducted a number of cost of service studies that differed with respect to the methods used to classify and allocate production plant costs, but relied primarily on the results of one of these studies as the basis for the proposal to increase residential rates by 5.5% in 2013 and by an additional 3.2%

in 2014. This “Base Case” COSS appears to allocate more production and distribution plant costs to the residential class than is reasonable. The Base Case COSS overstates the demand-related portion of production plant costs and then allocates more of this (overstated) demand-related portion to the residential class than is appropriate. Likewise, the Base Case COSS relies on a flawed method for classifying distribution plant costs that overstates the customer-related portion of such costs.

Given these problems with the Base Case COSS, the Commission should reject the Company’s proposed residential rate increases for the 2013 and 2014 test years. Instead, the Commission should direct WEPCO to allocate the approved level of revenue requirements based on the following modifications to the Base Case COSS:

- Classify 43% of 2013 test year production plant costs as demand-related, and the remaining 57% as energy-related.
- Classify 100% of 2014 test year production plant costs for the Rothschild biomass and solar facilities (along with associated biomass tax grant credits) as energy-related.
- Allocate demand-related production plant costs on the basis of each customer class’s contribution to the average of the twelve monthly system coincident peaks.
- Classify all distribution-feeder costs as demand-related.

The Company also lacks a reasonable basis for its proposal to increase residential facilities charges for single-phase and three-phase service by 40%. In fact, the analysis developed by WEPCO to support the proposed increase appears to indicate that facilities charges should be lowered. Consequently, the Commission should reject the Company’s proposal and instead find that it is reasonable to maintain facilities charges at current levels. If any increase to residential revenues is allowed by the Commission, it should be recovered solely through the energy charge.

Finally, WEPCO proposes to eliminate the residential load-control program based on an assertion that the program is no longer cost-effective under prevailing market conditions. However, the Company has not offered any evidence to support this claim. The Commission should therefore deny the Company's request to terminate the program at this time and direct the Company to file a comprehensive analysis of the impact of current capacity conditions on the economic performance of the residential load-control and non-residential interruptible programs.

II. Classification and Allocation of Production Plant Costs

Q: Please describe the Company's requested rate increase.

A: For the 2013 test year, the Company is requesting that electric rates be increased on average by 3.6% in order to recover an expected revenue deficiency (excluding fuel costs and after adjusting for the biomass tax grant) of $99.3 million. Of the total $99.3 million requested revenue increase, WEPCO proposes to allocate $62.3 million to residential customers.[1] This amount represents a 5.5% increase over residential revenues under current rates.

For the 2014 test year, the Company requests that electric rates be increased by an additional 3.6% over proposed rates for the 2013 test year in order to recover an expected revenue deficiency of $103.8 million. The revenue deficiency for the 2014 test year reflects the impacts of the addition of two new renewable projects to ratebase and a reduction in the amount of the biomass tax

[1] Ex.-WEPCO/WG-Rogers-15, Schedule No. 1 (PSC REF #: 164661).

grant relative to that for the 2013 test year. The Company proposes to increase residential rates by an additional 3.2%, or $37.7 million, in order to recover the portion of the $103.8 million revenue deficiency allocated to the residential class.

Q: What is the basis for the proposed residential rate increase?

A: According to Mr. Rogers, WEPCO conducted a number of cost of service studies that differed with respect to the methods used to classify and allocate production plant costs, in order to provide the Commission "points on a reasonable range of results."[2] These studies varied the proportion of demand-related to energy-related production plant costs, ranging from 100% demand-related and 0% energy-related to 50%/50% demand/energy.[3] In addition, the studies allocated demand-related costs on the basis of each customer class's contribution to either the average of the twelve monthly system coincident peaks ("12CP") or the average of the four summer coincident peaks ("4CP").[4]

According to Mr. Rogers, the Company relied primarily on the results of one study as "appropriate for initial rate design guidance."[5] This "Base Case"

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[2] Direct-WEPCO/WG-Rogers-10, ll. 12-13 (PSC REF #: 164646).

[3] Classifying all production plants as demand-related implies that, from a generation planning perspective, production capacity costs are incurred solely for the purposes of meeting system reliability requirements. On the other hand, classifying all costs as energy-related implies that production capacity costs are incurred solely for meeting energy requirements. Classifying costs as 50% demand-related and 50% energy-related therefore implies that 50% of costs are incurred to meet reliability, with the remainder incurred to meet energy requirements.

[4] The Company also performed two studies that allocate energy-related costs using LMP-weighted energy allocators based on historical data. However, according to Mr. Rogers, these studies were for illustrative purposes only, due to the "difficulty of developing the allocators such that they are consistent with the test-year forecast." (Direct-WEPCO/WG-Rogers-14, ll. 4-5.)

[5] Direct-WEPCO/WG-Rogers-15, line 18.

COSS classifies 60% of production plant costs as demand-related and the remaining 40% as energy-related. Moreover, the Base Case COSS allocates demand-related production plant costs using the 4CP allocator.

Q: How did the Company derive the 60%/40% demand/energy classification of production plant costs used in the Base Case COSS?

A: The Company used the "Equivalent Peaker" method to classify production plant costs as either demand-related or energy-related. As WEPCO recognizes, the Equivalent Peaker method reflects investment decision-making under typical generation expansion planning practices. The Equivalent Peaker method classifies fixed costs (i.e., capital and fixed O&M costs) for a peaking unit as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. The Equivalent Peaker method likewise classifies fixed costs for a baseload or intermediate unit *in excess of peaking fixed costs* (so-called "capitalized energy" costs) as energy-related, since these incremental fixed costs are incurred to minimize the total cost of meeting an increase in energy requirements.

As indicated in Ex.-WEPCO/WG-Rogers-5 (PSC REF #: 164651), the Company's application of the Equivalent Peaker method classified about 50% of production plant costs as demand-related and about 50% as energy-related. However, according to Mr. Rogers, WEPCO decided to use the 60%/40% demand/energy split derived in the last rate case for the Base Case COSS, since "this seems like a rather substantial change from one rate case to the next."[6]

Q: Is the Company's decision to rely on the classification from the previous rate case reasonable?

[6] Direct-WEPCO/WG-Rogers-16, ll. 20-21.

A: No. This decision arbitrarily elevates the Company's judgment as to whether a change is too large over empirical results that reflect, as Mr. Rogers acknowledges, "substantial increases in the investment in wind plant" since the last rate case.[7]

Q: Should WEPCO instead classify production plant costs according to the results of the current application of the Equivalent Peaker method?

A: No. The Company's current application of the Equivalent Peaker method is flawed in that it overstates the demand-related portion of wind plant production costs. From a cost-causation perspective, 100% of wind plant production costs should be classified as energy-related, since such plant is added to the system for the purposes of meeting renewable standards that vary with energy, not for the purposes of meeting reliability requirements that are driven by peak load.

Based on the calculations in Ex.-WEPCO/WG-Rogers-5, assigning all wind costs to energy results in a classification of 43% of the Company's production plant costs as demand-related and 57% as energy-related.

Q: Would the Company's current classification of wind plant costs be reasonable, if the Company's wind plant had been added to meet both renewable and reliability requirements?

A: No, because the Company's current classification overstates the contribution of wind capacity to planning reserves. For the purposes of classifying wind plant costs, WEPCO assumes that every megawatt of installed wind capacity contributes a megawatt to planning reserves. However, for capacity-planning purposes, the Company assumes a contribution to planning reserves of only a small fraction of that installed megawatt of wind capacity due to the intermittent

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[7] Direct-WEPCO/WG-Rogers-16, line 19.

nature of wind generation. Specifically, according to the Company's response to 14-CUB/Inter-5 (PSC REF #: 171429), WEPCO assumes that there are about 0.13 megawatts available to meet planning reserves for each megawatt of installed wind capacity on the Company's system.

Based on the calculations in Ex.-WEPCO/WG-Rogers-5, classifying wind on the basis of the Company's estimate for effective contribution to planning reserves results in a classification of 44% of the Company's production plant costs as demand-related and 56% as energy-related.

Q: How are 2014 test year production plant costs for the two new renewable projects classified in the Base Case COSS?

A: Although Mr. Rogers does not describe how the costs for the Rothschild biomass plant and the solar plant are classified in the Base Case COSS, the Company's response to 14-CUB/Inter-3 (PSC REF #: 171429) indicates that the 2014 production plant costs for these two new facilities are classified using the same 60%/40% demand/energy split as applied to all other production plant.

Q: Is it reasonable to classify production plant costs for these two renewable facilities using a 60%/40% demand/energy split?

A: It would not be appropriate to classify any of the production plant costs for these facilities as demand-related, since these facilities are not being added for the purposes of serving reliability requirements. Instead, as noted by Company witness David J. Ackerman, the Company has invested in these facilities in order to provide additional renewable energy:

> … The Rothschild biomass project which was approved in Docket No. 6630-CE-305 result[s] from the Applicant pursuing additional renewable energy projects to satisfy the mandate established by Wisconsin's Renewable Portfolio Standard. The Applicant's filing also includes a solar project to satisfy an earlier agreement with environmental advocacy groups.[8]

Consequently, the production plant costs for these facilities should be classified as 100% energy-related.

Q: How does the Company propose to allocate demand-related production plant costs in the Base Case COSS?

A: Although WEPCO has relied on the 12CP allocator in the past, the Company now proposes to use a 4CP allocator to allocate demand-related production plant costs. As noted by Mr. Rogers, the change from a 12CP to a 4CP allocator will shift costs from the large to the small customer class.[9]

Q: Why is the Company proposing at this time to switch from a 12CP to a 4CP allocator?

A: According to Mr. Rogers, the pattern of monthly peaks has changed over time, from one that is relatively flat across months to one where "the difference between our summer peaks and winter peaks have become more pronounced."[10] Based on this changing pattern, Mr. Rogers concludes that:

> Although what we've argued in the past, (that we must plan for capacity in all twelve months of the year), is still true, our summer peaks are clearly the primary determinant of our capacity planning.[11]

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[8] Direct-WEPCO/WG-Ackerman-10, ll. 3-8 (PSC REF #:161782).

[9] Direct-WEPCO/WG-Rogers-38, ll. 9-11.

[10] Direct-WEPCO/WG-Rogers-13, ll. 5-6.

[11] Direct-WEPCO/WG-Rogers-13, ll. 6-8.

Q: Has WEPCO reasonably justified its proposal to switch from a 12CP to a 4CP allocator?

A: No. While WEPCO has provided evidence that the gap between summer and winter peaks has grown over time, the Company has not shown that the need for new reserve capacity is more strongly driven by summer peaks today than it has been in the past. In other words, even when the gap between summer and winter peaks was lower in the past, it is likely that summer peaks were the "primary determinant" of the need for new reserve capacity. What the Company has failed to show is that the gap is now large enough that summer peaks have become not just the primary, but the sole determinant of the Company's capacity planning.[12] As such, WEPCO has not reasonably justified its proposal to allocate demand-related costs as if capacity planning were driven solely by summer peaks.

III. Classification and Allocation of Distribution Costs

Q: How does the Company classify and allocate distribution plant costs to customer classes?

A: The Company classifies all distribution substation costs (FERC Accounts 360 and 361) as demand-related, and allocates such costs based on class non-coincident peaks (NCP). Services (FERC Account 369) are considered to be customer-related and allocated on the basis of the estimated number of service drops for each class. Costs for transformers (FERC Account 368) and meters (FERC Account 370) are directly assigned. Finally, WEPCO classifies distribution-feeder costs (FERC Accounts 364 through 367), including poles and

[12] In fact, as noted above, the Company still believes that it "must plan for capacity all twelve months of the year."

conductors, as either demand-related or customer-related based on a minimum-size analysis. The Company then allocates demand-related costs based on class NCP and customer-related costs based on number of customers.

A minimum-size analysis attempts to estimate the cost to install the same number of units (e.g., poles, conductor-feet) as are currently on the system, assuming that each of those units are the smallest size currently used on the distribution system. The cost of this minimum-size system is then deemed to be customer-related, with the remaining cost classified as demand-related.

Q: Do minimum-size analyses generally produce reasonable classifications of costs?

A: No. As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, these analyses are fundamentally flawed because minimum-system costs are neither properly classified as wholly customer-related nor demand-related.[13] Instead, Bonbright, Danielson, and Kamerschen argue that such costs are inherently "unallocable":

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs …, while it is also denied a place among the customer costs …, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs…. But fully-distributed cost analysts dare not avail themselves of this solution, since they are prisoners of their own assumption that "the sum of the parts is equal to the whole." They are therefore under impelling pressure to fudge their cost apportionments by

[13] In other words, these costs are not driven primarily by either changes in the number of customers or by changes in customer demand, but instead may depend on such factors as customer density or terrain.

> using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[14]

Residential customers are especially burdened when a high percentage of these unallocable costs are inappropriately dumped into the customer-cost bin.

In addition, in a 1981 article, George Sterzinger identified a specific flaw in the minimum-size approach that could result in over-allocation of costs to the residential class.[15] The problem arises because the minimum-size method typically defines the minimum system to include equipment that would carry a large portion of the average customer's load. For example, assume that the minimum-size line conductor is large enough to cover the average load of residential customers. In this case, only those costs incurred for the minimum-size conductors are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method would not only allocate these minimum-size conductor costs to the residential class as customer-related costs, but would also inappropriately allocate a portion of the remaining costs for larger conductors to residential customers as demand-related costs, even though the costs for these larger conductors were not incurred to serve residential load.[16]

Q: Is there a reasonable alternative to the minimum-size method for classifying distribution-feeder costs?

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[14] Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, VA: Public Utilities Reports, 1988., p. 492.

[15] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, July 2, 1981.

[16] According to Mr. Rogers, the Company partially accounts for this problem by assuming that only 50% of the cost of the minimum-sized conductor is customer-related. (Direct-MGE-Rogers-25, ll. 17-20.)

A: Yes. A reasonable and reasonably straightforward alternative approach, and one that has been used in other jurisdictions, would be to classify all pole and conductor costs as demand-related.

IV. Residential Facilities Charge

Q: What is the Company's proposal with respect to the facilities charge for residential rates?

A: The Company proposes to increase the residential facilities charge by 40%, from $7.60 per month to $10.65 per month for single-phase customers and from $15.21 per month to $21.29 per month for three-phase customers.

Q: What is the basis for the Company's proposed increase?

A: According to Mr. Rogers, residential facilities charges are designed to recover allocated costs for metering, service drops, customer accounting, customer service, and uncollectibles. The Company calculated the total allocated amount for these residential 'base' customer costs from the Base Case COSS, and based on that calculation concluded that the facilities charge should be increased by 40%.

Q: Does the Company's calculation of residential 'base' customer costs support the proposal to increase residential facilities charges by 40%?

A: No. To the contrary, the Company's calculation of 'base' customer costs from the Base Case COSS appears to indicate that the current residential facilities charges should be reduced.

Based on data provided in Schedule 2 of Ex.-WEPCO/WG-Rogers-15, the average residential facilities charge, weighted across single-phase and three-phase customers, is currently about $7.60 per month. In contrast, as indicated in the Company's response to Request for Production 8-CUB/RFP-5 (PSC REF #: 169608), the Company calculates that residential 'base' customer costs from the Base Case COSS amount to about $7.18 per month, or about 5.5% less than the current facilities charge.[17]

Q: Has the Company explained why it is proposing to increase a facilities charge that already recovers more than 'base' customer costs?

A: Not to my knowledge. However, Mr. Rogers suggests one rationale when he states that at the proposed levels for the facilities charges:

> … the 'base' customer costs are recovered by the facilities charges, but the total customer-related distribution costs are still not completely recovered by the facilities charges.[18]

In other words, Mr. Rogers suggests that WEPCO is proposing to expand the scope of the facilities charge to recover not just 'base' customer costs, but all distribution costs classified as customer-related in the Base Case COSS.

Q: Would it be reasonable to recover all distribution costs classified in the Base Case COSS as customer-related through the residential customer charge?

A: No. As discussed above, the Base Case COSS misclassifies demand-related distribution costs as customer-related by relying on the minimum-system method. As a result, the Base Case COSS overstates the total amount of distribution costs appropriately allocated to the residential class, and overstates the portion of the allocated amount that is appropriately classified as customer-related.

In addition, while it may be reasonable to classify certain costs as customer-related for the purposes of allocating such costs among customer

[17] See Ex.-CUB-Wallach-2 for an excerpt from the Company's response.

[18] Direct-WEPCO/WG-Rogers-40, ll. 18-20.

classes in the COSS, it is not appropriate to recover all such costs allocated to the residential class through a fixed facilities charge. For example, a number of customer-classified distribution costs – such as services or uncollectible accounts and collection expense – are likely to vary with the size of the customer (in revenues, sales, or demand). If such costs were recovered through a fixed facilities charge, then the smallest residential customers (with the least-expensive distribution equipment) would be required to pay the average of customer costs attributable to all sizes of residential customers. In other words, if all customers were to pay the same customer charge regardless of size, then low-usage residential customers would subsidize high-usage residential customers' distribution costs.

Q: What do you recommend with regard to the Company's proposal to increase residential facilities charges?

A: The Company lacks a reasonable basis for its proposal to increase residential facilities charges for single-phase and three-phase service by 40%. In fact, the analysis developed by WEPCO to support the proposed increase appears to indicate that facilities charges should be lowered. Consequently, the Commission should reject the Company's proposal and instead find that it is reasonable to maintain facilities charges at current levels. If any increase to residential revenues is allowed by the Commission, it should be recovered solely through the energy charge.

V. Residential Load Control

Q: What is the Company's proposal for the Energy Partners residential central air conditioning load-control program?

A: According to Mr. Rogers, the Company proposes to eliminate this program, because "given the current availability of capacity, this program is no longer cost effective."[19]

Q: Has the Company offered any analytical support for its assertion that the residential load-control program is no longer cost-effective?

A: Not that I am aware of.

Q: Given current market conditions, has the Company evaluated whether non-residential interruptible tariffs continue to be cost-effective?

A: Again, not to my knowledge.

Q: What do you recommend with regard to the Company's proposal to eliminate the residential air conditioning load-control program?

A: The Commission should deny the Company's request to terminate the program at this time and direct WEPCO to file a comprehensive analysis of the cost-effectiveness of the residential load-control and non-residential interruptible programs under current market conditions.

Q: Does this complete your direct testimony?

A: Yes.

[19] Direct-WEPCO/WG-Rogers-56, ll. 12-13.