BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates	)))	Docket No. 3270-UR-118

DIRECT TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
August 27, 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, Madison Gas and Electric Company (MGE or "the Company") filed an application to increase electric rates by 5.8% in order to recover an expected revenue deficiency of $22.4 million in the 2013 test year. Based on the results of three embedded cost of service studies (COSS), the Company proposes to increase average rates for the residential class by 6.2%. In addition, MGE proposes a radical reformulation of its rate designs that would recover the bulk of residential revenue requirements through the customer charge. As a first step in a transition to this new rate structure, the Company further proposes for 2013 rates to increase the residential customer charge from $8.70/month to $12.17/month, or by about 40%.

This testimony addresses two aspects of the Company's filing: (1) the methods used in the cost of service studies to allocate production and distribution plant costs; and (2) the basis for the Company's proposal to restructure residential rates. The first element is discussed in the pre-filed direct testimony of Company witness Steven S. James. The proposal to restructure

residential rates and to increase the residential customer charge is discussed in the pre-filed direct testimony of Company witness Gregory A. Bollom.

Q: Please summarize your findings and recommendations.

A: The Company relied on the results of three cost of service studies to develop its proposal for a 6.2% increase in residential rates. These three studies differ primarily with respect to the methods used to allocate production and distribution plant costs. Of the three studies, the "Location" COSS allocates costs in a fashion that most reasonably reflects each class's responsibility for such costs. In contrast, the "Standard" COSS appears to allocate more production and distribution plant costs to the residential class than is appropriate, while the "Time-of-Day" COSS appears to overstate the appropriate residential allocation of distribution plant costs. The Commission should therefore give little weight to the results of the Standard and Time-of-Day studies.

With respect to residential rate design, MGE lacks a reasonable basis for its proposal to shift costs from the energy charge to the customer charge. Redesigning residential rates in the fashion proposed by the Company would inappropriately shift load-related costs to the customer charge, dramatically dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and exacerbate the subsidization of larger residential customers' costs by these lower-usage customers. Consequently, the Commission should reject both the Company's proposal to restructure residential rates and its proposal to transition to restructured rates by increasing the residential customer charge from $8.70/month to $12.17/month for 2013 rates.

II. Cost Allocation

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

A: The Company is requesting that electric rates be increased on average by 5.8% in order to recover an expected revenue deficiency of $22.4 million in the 2013 test year. Of the total $22.4 million requested revenue increase, MGE proposes to allocate $7.72 million to residential customers.[1] This amount represents a 6.2% increase over residential revenues under current rates.

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

A: According to Mr. James, the proposed residential rate increase was derived using as "guidelines" three cost of service studies. These three studies differ with respect to the methods used to allocate production and distribution plant costs, as well as with respect to the allocator for energy-related costs. Specifically, the three studies differ as follows:

- The "Standard" COSS classifies all production plant costs as demand-related, and allocates such costs on the basis of each customer class's contribution to the average of the twelve monthly system coincident peaks ("12CP"). Distribution plant costs are classified as either demand-related or customer-related based on a minimum-system analysis. Demand-related costs are allocated based on class non-coincident peaks and customer-related costs are allocated based on number of customers. All energy-related costs are allocated based on each class's contribution to total generation (i.e., sales plus losses).
- The "Time-of-Day" COSS classifies 60% of non-peaking production plant costs as demand-related and the remaining 40% as energy-related.

[1] Ex.-MGE-James-2, Schedule No. 1, p. 1 (PSC REF #:166582).

(Peaking plant costs are classified as 100% demand-related.) Demand-related production costs are allocated using the 12CP allocator and energy-related costs are allocated based on each class's contribution to on-peak generation. Distribution costs are allocated in the same fashion as in the Standard COSS. All energy-related costs are allocated using the on-peak energy allocator.

- The "Location" COSS classifies and allocates production plant costs in the same fashion as in the Time-of-Day COSS. All distribution plant costs, other than for meters and services, are classified as demand-related and allocated based on non-coincident peak. (All meter and services costs are classified as customer-related.) All energy-related costs are allocated using the on-peak energy allocator.

Q: Why did the Company perform these three cost of service studies?

A: According to Mr. James:

> I have offered three studies in this case to provide the Commission with a range of costs produced by various accepted cost methodologies. In past cases, the Commission has found it reasonable to rely on the results of more than one cost of service study when allocating revenue responsibility. Depending on different factors the Commission may consider as to how the rate increase in this case should be apportioned among the customer classes, some studies may be deemed more appropriate than others.[2]

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

A: Yes. Of the three studies, the Location COSS allocates costs in a fashion that most reasonably reflects each class's responsibility for such costs. In contrast, the Standard COSS appears to allocate more production and distribution plant costs to the residential class than is appropriate, while the Time-of-Day COSS

[2] Direct-MGE-James-8, ll. 18-23 (PSC REF #:166580).

appears to overstate the appropriate residential allocation of distribution plant costs.

Q: How does the Standard COSS over-allocate production plant costs to the residential class?

A: The Standard COSS classifies all production plant costs as demand-related, implying that, from a generation planning perspective, production capacity costs are incurred solely for the purposes of meeting system reliability requirements. This assumption is inconsistent with investment decision-making under typical generation expansion planning practices, where plant investment choices are driven by both reliability and energy requirements.

Specifically, investments in peaking plant are appropriately classified as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. On the other hand, baseload or intermediate plant costs *in excess of peaking plant costs* (so-called "capitalized energy" costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

Q: Does MGE recognize that the Standard COSS classification of production plant costs is inconsistent with generation expansion planning?

A: Yes. According to Mr. James, the Time-of-Day and Location studies classify a portion of production plant costs as energy-related in order to reflect "the trade-off between operating expense and initial plant cost made by MGE when it decided what plants should be built."[3]

[3] Direct-MGE-James-7, ll. 13-15 (PSC REF #:166580).

Q: What is the basis for the 60%/40% demand/energy split of production plant costs in the Time-of-Day and Location studies?

A: According to Mr. James, these studies simply adopt the split used by Commission Staff in previous rate cases.[4]

Q: Do you have any concerns about the 60%/40% split assumed by Commission Staff?

A: I am concerned that this split – which Commission Staff has applied generically across utilities –may not reasonably reflect the actual proportion of demand to energy-related investments in the Company's production plant.

I am aware of two recent rate cases for other Wisconsin utilities where this split was derived based on actual utility production plant cost data, and in both cases the split implied a greater proportion of energy-related costs. In Docket No. 05-UR-106, Wisconsin Electric Power Company calculated a 50%/50% split between demand-related and energy-related costs.[5] And in Docket No. 4220-UR-117, I derived a 30%/70% demand/energy split for Northern States Power Company's production plant costs.[6]

Q: How do the Standard and Time-of-Day studies over-allocate distribution plant costs to the residential class?

A: These studies classify distribution costs as customer-related or demand-related based on a minimum-system analysis. Minimum-system methods are generally unreliable and tend to misclassify demand-related costs as customer-related

[4] Direct-MGE-James-7, ll. 22-23.

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

[6] Docket No. 4220-UR-117, Direct Testimony of Jonathan Wallach, p. D2.33, ll. 12-13 (PSC REF#: 154438).

costs. As a result, cost allocations based on minimum-system classifications overstate the appropriate allocation of distribution costs to residential customers.

Q: How does MGE apply the minimum-system approach in the Standard and Time-of-Day studies?

A: The Company first classifies distribution plant costs (FERC Accounts 364 through 368) as either demand-related or customer-related based on a minimum-size analysis.[7] The Company then allocates demand-related costs based on class non-coincident peaks and customer-related costs based on number of customers.[8]

A minimum-size analysis attempts to estimate the cost to install the same number of units (poles, conductor-feet, transformers) 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

[7] All distribution substation costs are considered to be demand-related, while all meter and service costs are considered to be customer-related.

[8] Meter and service costs are allocated using a weighted customer allocator.

customer-related nor demand-related.[9] 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 using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[10]

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.[11] 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 transformer is large enough to cover the average load of residential customers. In this case, only those costs incurred for the minimum-size transformers are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method would not only

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[9] 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.

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

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

allocate these minimum-size transformer costs to the residential class as customer-related costs, but would also inappropriately allocate a portion of the remaining costs for larger-sized transformers to residential customers as demand-related costs, even though the costs for these larger transformers were not incurred to serve residential load.

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

A: Yes. A reasonable and reasonably straightforward alternative approach would be to classify meters and services as customer-related and all other distribution plant costs as demand-related. This is in fact the approach used in the Location COSS.

III. Rate Design

Q: What is the Company's proposal with respect to residential rate design?

A: According to Mr. Bollom, the Company proposes a radical redesign of residential rates that would recover all allegedly "fixed" costs through the customer charge. The Company further proposes to transition to this "straight fixed/variable" rate design over several years, and as a first step in this transition to increase the residential customer charge from $8.70 per month to $12.17 per month, or by about 40%, for 2013 rates.

Q: By what amount would MGE have to increase the residential customer charge in order to recover all of the costs the Company considers to be "fixed"?

A: According to the Company's response to Interrogatory No. 2-CUB/Inter-1 (PSC REF #: 168381), the customer charge would have to increase to $73.32 per

month, or by more than eight times the current level, in order to recover all costs allocated to the residential class under the Company's COSS that MGE considers to be "fixed."

Q: What would be the effect on the average residential energy rate, if recovery of all allegedly "fixed" costs were shifted from the energy charge to the customer charge?

A: If the customer charge for the Rg-1 rate class were increased to $73.32 per month, the average energy rate (for distribution and electricity service combined) would have to be reduced dramatically from about 14¢/kWh to about 4¢/kWh.[12] In this case, the energy rate for distribution service would be zero, since all distribution costs would be considered to be "fixed" under the Company's proposal.

Q: What are the "fixed" costs that MGE proposes to recover through the residential customer charge?

A: Based on data provided in the Company's response to Request for Production No. 2-CUB/RFP-5 (PSC REF #: 163894), MGE apparently considers all costs that are classified as customer-related in the COSS to be fixed and thus recoverable through the residential customer charge. In addition, MGE includes all costs (whether generation, transmission, or distribution) classified as demand-related in the category of "fixed costs" to be recovered through the residential customer charge. Thus, from the Company's perspective, the only non-fixed costs are those that are classified in the COSS as energy-related.

According to the Company's response to Interrogatory No. 2-CUB/Inter-1 (PSC REF #: 168381), customer-related costs would contribute $26.75, or about

[12] This calculation is based on the allocation results from the Time-of-Day COSS.

36%, to the total residential customer charge of $73.32 under the Company's proposal. Demand-related costs would contribute the remaining $46.57, or about 64%.[13]

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

A: No. The derivation of the customer-related portion of the proposed customer charge is based on the results of the Time-of-Day COSS. As discussed above, the Time-of-Day (as well as the Standard) COSS misclassifies demand-related distribution costs as customer-related by relying on the minimum-system method. As a result, the Time-of-Day 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 classes in the COSS, it is not appropriate to recover all such costs allocated to the residential class through a fixed customer 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 customer 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,

[13] According to the Company's response to Request for Production No. 2-CUB/RFP-5 (PSC REF #: 163894), the customer-related and demand-related portions of the $73.32 total amount were determined based on the results of the Time-of-Day COSS.

if all customers were to pay the same customer charge regardless of size, then small customers would subsidize larger customers' distribution costs.

Q: What is the basis for the Company's proposal to recover all demand-related costs through the residential customer charge?

A: The Company has not provided any rationale for recovering demand-related distribution costs through the customer charge.

With respect to demand-related generation and transmission costs, the Company offers the following explanation in response to Interrogatory No. 2-CUB/Inter-3 (PSC REF #: 168383):

> Demand-related costs associated with generation and transmission are typically associated with the size of a customer's maximum load and do not vary with the amount of energy used. For residential and small commercial customers with only energy meters, these costs should be treated as fixed and recovered through some type of fixed charge.

In other words, MGE acknowledges that demand-related generation and transmission costs are not fixed, but in fact vary with customer load. However, the Company asserts that these costs vary solely with "maximum load" and therefore presumably should be recovered through a demand charge. Given that residential meters do not support the levy of a demand charge, the Company believes that demand-related charges should instead be recovered through the customer charge.

Q: Would it be appropriate to recover demand-related distribution costs through the residential customer charge?

A: No. Such costs may appear "fixed" when considered in the short-term context of utility cost recovery, since the revenue requirements associated with debt service

and maintenance for a given set of lines and transformers in any year is unlikely to vary much with load or sales in that year.[14]

However, from the longer-term perspective of cost causation and price signals, distribution investments are variable with respect to customer demand. Increased loading of existing lines, conduit, transformers, substations, and other distribution equipment reduces the lives of that equipment and requires the installation of more and larger equipment. Higher loads may even require more poles and towers, to carry additional primary circuits, and higher poles and towers, to allow for higher distribution voltages. In general, energy charges better reflect the causation of these costs than fixed customer charges, and hence provide the better price signal.

Q: Has MGE offered a valid basis for recovering demand-related generation and transmission costs through the customer charge?

A: No. As the Company acknowledges, these demand-related costs vary with customer load, and thus are more reasonably recovered through a volumetric rather than a fixed charge in order to provide appropriate price signals to customers. Shifting recovery of such demand-related costs to the customer charge would seriously distort price signals, since consumers would no longer benefit from actions that reduce maximum demand and thus reduce demand-related costs. Likewise, consumers would no longer be penalized for increases in their peak demands. In other words, the Company's proposal would misleadingly and inefficiently signal to consumers that there is no economic gain or loss associated with changes in peak demand.

[14] Higher loads, especially in the summer, are likely to result in failure of more transformers and underground lines, so current costs may vary with current load to some extent. However, this is probably a small effect, compared to total distribution costs.

In contrast, recovering demand-related costs through energy charges would appropriately signal to consumers the benefit or harm from any changes to peak demand that accompany changes in energy usage. For changes in energy usage that have the same load shape – i.e., has the same load factor – as that for the residential class, the price signal through an energy charge would be identical to that provided through a demand charge.[15]

Q: Why is MGE proposing to radically redesign residential rates at this time?

A: Mr. Bollom offers the following reasons for restructuring residential rates:

- Current rate designs reduce the competitiveness of the Company's commercial and industrial rates against those in states that have undergone restructuring and instituted market pricing of generation.
- Current rate designs confuse customers who invest in energy-efficiency measures, since bill savings in one year may be offset in part by rate increases in following years.
- The proposed restructuring "is a logical extension of the PSCW's policy of sending more accurate price signals" through advanced metering.
- Current rate designs inappropriately and inequitably shift "fixed" costs from customers who install distributed generation to other customers.

Q: Are these concerns regarding the current residential rate design valid?

A: No. For the most part, such concerns are unwarranted, since as discussed above the current rate design reasonably reflects cost causation and provides

[15] For changes in energy usage that are "peakier" than residential average usage, an energy charge would understate the impact on demand-related costs. In the extreme, the price signal would be negated for measures that shift usage off of or on to the system peak hour without any change in overall energy usage.

appropriate price signals regarding changes in customers' peak demands and energy usage.[16]

In addition, the concern about customer confusion is misguided. If customers are confused about the relationship between bill savings and rate increases from energy efficiency, the Company's response should be to better inform customers about the economic benefits from reducing usage through energy efficiency, the fact that cost-effective efficiency investments reduce bills even when accounting for short-term rate increases, and about the fact that efficiency investments reduce utility costs and thus rates over the long term.

Q: Other than the conceptual arguments supporting the proposed rate restructuring, has MGE offered any justification for its specific proposal to increase the residential customer charge for 2013 rates to $12.17 per month?

A: Mr. Bollom believes that the proposed customer charge for 2013 will appear reasonable to MGE customers because members of Wisconsin's electric cooperatives apparently are satisfied with higher customer charges (or at least not so dissatisfied that they chose to unseat board members.) By Mr. Bollom's thinking, if cooperative members find their current customer charges acceptable, then the Company's customers should also find a higher customer charge to be reasonable.

If the Company's residential customers were to base their judgments of the proposed customer charge on comparisons with other utilities' customer charges,

[16] The concern about the competitiveness of commercial and industrial rates is also irrelevant to the issue of the reasonableness of current residential rate designs. The competitiveness of the Company's non-residential rates depends not on how costs allocated to the residential class are recovered from residential customers, but on the extent to which non-residential generation rates exceed competitive market prices.

presumably they would be more inclined to look at customer charges paid by customers at Wisconsin's other investor-owned utilities. If so, as indicated in the following table, they would find that the customer charge proposed by MGE would be 1.4 to two times the customer charges paid by residential customers of the four other investor-owned utilities.

Table 1

	Monthly Customer Charge[17]	MGE Multiple
MGE (Proposed)	$12.17	
MGE (Current)	$8.70	1.4
Northern States Power	$8.00	1.5
Wisconsin Electric Power	$7.60	1.6
Wisconsin Power and Light	$7.67	1.6
Wisconsin Public Service (Current)	$5.70	2.1
Wisconsin Public Service (pre-RSM)[18]	$8.40	1.4

Q: What do you recommend with regard to the Company's proposal to redesign residential rates and increase the residential customer charge?

A: The Company requests that the Commission "determine that it is appropriate and necessary for MGE to move to rate designs that recover fixed costs through some type of fixed charges."[19] This request should be denied. The Company's proposal would unreasonably shift to the customer charge costs that are more

[17] MGE Response to 2-CUB/RFP-3, page 31 of 80 (PSC REF #: 169088) and individual utility tariffs.

[18] Per Docket No. 6690-UR-121, Direct-WPSC-Ferguson-10 (PSC REF #: 164605), Wisconsin Public Service Corporation's current customer charge was reduced upon implementation of its pilot revenue stabilization mechanism (RSM), which is to terminate at the end of this year.

[19] Direct-MGE-Bollom-3, ll. 21-23 (PSC REF#: 166575).

appropriately recovered through energy charges. Such a shift would distort price signals and inequitably burden smaller customers.

Lacking a reasonable basis for shifting costs into the customer charge, the Company's specific proposal for increasing the 2013 customer charge to $12.17 per month should also be rejected. Any increase to residential revenues allowed by the Commission should be recovered solely through the energy charge.

Q: Does this complete your direct testimony?

A: Yes.