BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service	)	
Corporation for Authority to Adjust	)	Docket No. 6690-UR-122
Electric and Natural Gas Rates	)	

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

August 29, 2013

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 sixty 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, 6680-FR-104, 3270-UR-118, 05-UR-106, and 4220-UR-118. 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 29, 2013, Wisconsin Public Service Corporation (WPSC or "the Company") filed an application to increase electric and gas rates for the 2014 test year. This testimony addresses the following aspects of the Company's filing:

- The Company's proposal to indefinitely extend the currently approved Revenue Stabilization Mechanisms (RSM) for electric and gas service, as discussed in the additional direct testimony of Company witness David J. Kyto (filed on May 15, 2013.)
- The methods used by WPSC in its electric cost of service study to allocate the proposed 2014 test year electric revenue deficiency to the residential and small C&I classes, as described in the pre-filed direct testimony of Company witness Joylyn C. Hoffman Malueg.
- The Company's proposed rate design for residential and small C&I customers, including its proposals to increase the residential and small

C&I customer charges and to consolidate urban and rural rate schedules, as described in the pre-filed direct testimony of Company witness Russell T. Laursen.

Q: Please summarize your findings and recommendations with regard to the Company's proposal for the RSM.

A: The Company proposes to indefinitely extend the currently approved RSMs for electric and gas service. In addition, WPSC proposes elimination of the currently approved caps on annual RSM recoveries or credits.

The Commission should 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 apparently failed to provide incentives to management to continue voluntarily investing in energy efficiency programs beyond levels mandated for Focus on Energy programs or to continue supporting rate designs that improve price signals for customer conservation.

Q: Please summarize your findings and recommendations with regard to cost allocation and rate design.

The Commission staff audit finds a revenue deficiency for the 2014 test year of about $9.35 million, or about 0.97% of 2014 test year electric revenues under current rates. The Company's cost of service study of the Commission staff audit revenue requirements ("WPSC Audit COSS") allocates about $1.32 million of the total revenue deficiency across all residential and small C&I rate classes.

The WPSC Audit COSS understates the residential and small C&I revenue excess associated with the Commission staff audit revenue requirements, because it relies on classification methods that allocate more production and distribution plant costs to residential and small C&I rate classes than is appropriate. The Commission should therefore give little weight to the allocation results from the Company's cost of service analysis of the Commission staff audit revenue deficiency for the 2014 test year.

In the past, Commission staff has performed a cost of service study that more reasonably classifies and allocates production and distribution plant costs.[1] Presuming Commission staff will perform a similar analysis in this proceeding and in order to avoid duplication in the record, I intend to offer my proposed recommendation for allocation of the 2014 test year revenue deficiency in rebuttal testimony after I have had the opportunity to review Commission staff's cost of service studies.

With respect to rate design for residential and small C&I customers, WPSC lacks a reasonable basis for its proposal to increase customer charges. The Company's proposal would inappropriately dampen price signals to consumers for reducing energy usage, and exacerbate the subsidization of larger customers' costs by lower-usage customers. On the other hand, the Company's proposals to consolidate urban and rural rate schedules and to transfer residential three-phase customers to small C&I service appear reasonable.

I recommend that customer charges be set as shown in Table 1, with rate levels dependent on whether the Commission adopts my recommendation to terminate the RSM. These charges are designed to both mitigate the problems associated with the increases proposed by WPSC and accommodate the

[1] See, e.g., Docket No. 6690-UR-120, Petersen Exhibit 8.5, Location COSS (PSC REF#: 136935).

Company's proposals to consolidate urban and rural rate schedules and transfer residential three-phase customers to small C&I service.

Table 1. Proposed Monthly Customer Charges

	Terminate RSM	Extend RSM
Rg-1, 3, 5 Single Phase	$8.40	$5.70
Rg-2, 4, 6 Single Phase	$8.40	$5.70
Rg-1, 3, 5 Three Phase	$10.25	$10.25
Rg-2, 4, 6 Three Phase	$10.25	$10.25
Cg-1, 3 Single Phase	$8.50	$7.25
Cg-2, 4 Single Phase	$8.50	$7.25
Cg-1, 3 Three Phase	$10.25	$10.25
Cg-2, 4 Three Phase	$10.25	$10.25

Once I have had the opportunity to review Commission staff's cost of service studies, I will include in my rebuttal testimony proposed rate designs for the residential and small C&I rate classes that reflect my recommended revenue allocations and proposed customer charges.

II. Revenue Stabilization Mechanism

Q: Please describe the Company's proposal with regard to the Revenue Stabilization Mechanism.

A: The Company proposes to make permanent the four-year pilot RSM that was originally approved in Docket No. 6690-UR-119 as part of the Energy Efficiency Stipulation between WPSC and CUB ("Stipulation"). Specifically, WPSC proposes to indefinitely extend the currently approved RSMs for electric and gas service. In addition, the Company proposes elimination of the currently approved caps on annual RSM recoveries or credits ($14 million for electric; $8 million for gas).

Q: Why does WPSC want to indefinitely extend the currently approved RSMs for electric and gas service?

A: According to Mr. Kyto, the pilot RSMs worked as designed, allowing the Company to recover under-collections of margin revenues when actual sales were less than forecast and returning to ratepayers over-collections of margin revenues when actual sales were greater than forecast. As a result, "the RSMs moved WPSC toward indifference as to its actual sales volumes relative to the forecasts underlying its rates."[2]

Q: Why does WPSC want to remove the caps on annual RSM recoveries or credits?

A: Mr. Kyto asserts that "removing the caps would remove the remaining incentives that the caps provide for WPSC to maximize sales."[3] In its response to Interrogatory 4-CUB/Inter-4 (PSC REF#:187693), the Company describes these "remaining incentives" as follows:

> WPSC believes that it could take actions to cause customers who are served under the rate schedules subject to a capped RSM to use more electricity or gas than they would otherwise by less aggressively promoting energy efficiency measures to these customers.

Q: Do you agree with Mr. Kyto's claim that the RSMs worked as designed?

A: No. From CUB's perspective, the RSM was designed to do much more than move WPSC management "toward indifference" regarding sales volumes. The RSM was designed not to foster passive indifference, but to provide incentives for the Company to push beyond the status quo by aggressively investing in

[2] Direct-WPSC-Kyto-18, ll. 2-3.

[3] Direct-WPSC-Kyto-18, ll. 20-21.

comprehensive energy-efficiency efforts and actively pursuing innovative rate designs that offered tangible benefits to ratepayers:

> WPSC and its customers face a future of increasing costs driven by tight fuel and energy markets and increasing construction and environmental costs, including those intended to mitigate global warming. The nature of the response necessary to effectively address these future costs must include a comprehensive demand-side initiative that is significantly larger, broader and more diverse than current efforts…. At the heart of the stipulation is an agreement that in return for pursuing, facilitating, funding and supporting demand-side initiatives, a full decoupling mechanism will be tested on a pilot basis.[4]

The Company did meet its obligations to voluntarily increase funding of Focus on Energy (FOE) efficiency programs beyond mandated levels and to improve price signals by reducing residential and small C&I customer charges during the pilot phase of the RSM. However, the pilot RSM failed to promote a permanent realignment of management's financial interests with its ratepayers economic interests. While the Company seeks to preserve its financial interests by making the RSM permanent, it also proposes to reverse the gains to ratepayers from the Stipulation by terminating voluntary contributions to FOE funding and by increasing customer charges to pre-Stipulation levels.[5]

Q: Are you suggesting that management indifference to FOE energy-efficiency efforts is not preferable to management opposition?

A: No. However, I am suggesting that a utility that seeks to frustrate FOE efforts and maximize sales – for example, by intentionally under-promoting FOE

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[4] *Initial Brief of the Citizens Utility Board*, Docket No. 6690-UR-119, October 20, 2008, pp. 1, 3 (PSC REF#: 103042).

[5] In its response to Interrogatory 4-CUB/Inter-03 (PSC REF#: 187692), WPSC confirms that it is not offering to make permanent any of the provisions of the Stipulation other than those that pertain to the RSM.

programs – should be sanctioned for its bad actions, not provided a positive incentive to remain indifferent.

Q: How does the RSM benefit WPSC and its shareholders?

A: The RSM benefits the Company by assuring recovery of the test year forecast of the fixed-cost-related portion of revenues ("margin revenues"), regardless of the actual level of sales in the test year. In other words, the RSM provides a hedge against the risk that margin revenues (and thus earnings on fixed costs) will fall short of allowed levels because, for example, an economic downturn depresses sales.[6] As with a typical hedge, the protection on the downside comes at the "cost" of a foregone opportunity to over-earn on the upside.

Q: Does the RSM also offer a hedge against ratepayer risks?

A: Yes. However, the hedge against economic risk is inefficient, in the sense that the RSM mitigates risk when ratepayers least need it and exposes ratepayers to risk when they can least afford it.

The RSM provides ratepayers a hedge against the risk that their actual electricity or gas costs will be higher than forecast for the test year because, for example, strong economic growth has increased consumption. While the RSM offers ratepayers protection against the risk of higher energy costs in a robust economy, that insurance may be of little value to ratepayers whose incomes are rising along with their energy costs. On the other hand, during a prolonged economic downturn, the RSM will maintain energy spending at test-year levels and at a time when ratepayers incomes are falling, thereby making electricity or natural gas service increasingly unaffordable.

[6] The RSM does not hedge against the risk that actual fixed costs are greater than forecast and thus returns are less than allowed. On the other hand, the Company has the opportunity to over-earn by managing its costs.

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

A: The pilot RSM did not permanently align management's and customers interests with respect to investment in comprehensive energy-efficiency efforts or economically efficient rate designs. To the contrary, the Company is proposing to undo the gains achieved through the Stipulation. Consequently, the Commission should reject the Company's proposal and direct WPSC to terminate the RSM as of January 1, 2014.

Q: What do you recommend in the event that the Commission approves extension of the RSM?

A: In that event, I offer the following recommendations for Commission action:

- Reject the Company's proposal to indefinitely extend the RSM and instead extend the RSM for three years. In addition, require that the Company file annual reports on RSM performance in each year of the extension period.
- Reject the Company's proposal to eliminate the caps on annual RSM recoveries or credits. As experience in 2009 and 2010 indicates, caps could dramatically reduce ratepayer exposure during an economic downturn. According to Mr. Kyto, WPSC recovered about $43 million in RSM under-collections from electric and gas customers in 2009 and 2010. If not for the caps, the Company would have recovered about $92 million in RSM under-collections, or more than double the actual recovery.[7]
- 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

[7] Direct-WPSC-Kyto-17, ll. 11-12.

revenues provided that the overall portfolio of programs and services funded in the WPSC service territory are cost-effective as specified in paragraph 3.a. of the Stipulation.[8]

- Reject the Company's proposal to increase customer charges for the residential and small C&I rate classes. Instead, I recommend that customer charges be set at the rates shown in Table 3, below.
- Reduce the allowed return on equity as recommended by CUB witness Stephen G. Hill to account for reduced risk associated with decoupling.

III. Cost Allocation

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

A: The Company is requesting that electric rates be increased on average by 7.4% in order to recover an expected revenue deficiency of $71.1 million in the 2014 test year. Of the total $71.1 million requested revenue increase, WPSC proposes to allocate $33.6 million to residential and small C&I customers.[9] This amount represents a 7.1% increase over residential and small C&I revenues under current rates.

Q: What does the Commission staff audit find with regard to the expected revenue deficiency for the 2014 test year?

[8] In this case, "residential and commercial" refers to the rate classes that are subject to the RSM. Paragraph 3.a. of the Stipulation states, "The overall portfolio of programs and services so funded shall in all cases be designed to be cost-effective. If evaluations demonstrate that the overall programs and services funded pursuant to this paragraph are not cost-effective, WPSC's voluntary contributions under this paragraph shall be reduced to a cost-effective level."

[9] Ex.-WPSC-Laursen-1, Schedule 1.

A: In contrast with the Company's request, the Commission staff audit finds a revenue deficiency for the 2014 test year of only $9.35 million, or about 0.97% of 2014 test year electric revenues under current rates.[10] The Company's cost of service study of the Commission staff audit revenue requirements shows a revenue deficiency of about $1.32 million for residential and small C&I customers.[11] This amount represents a 0.27% increase over residential and small C&I revenues under current rates.

Q: Does the WPSC Audit COSS reasonably allocate the revenue deficiency estimated under the Commission staff audit?

A: No. The allocation of costs to customer classes in the WPSC Audit COSS does not reasonably reflect each class's responsibility for such costs. In particular, the WPSC Audit COSS appears to allocate more production and distribution plant costs to the residential and small C&I rate classes than is appropriate.

Q: How does the WPSC Audit COSS over-allocate production plant costs to the residential and small C&I classes?

A: The WPSC Audit 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

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[10] WPSC Audit Version of 2014 Electric Jurisdictional Model dated 7/12/13, Statement G, p. 6 (PSC REF#: 187443).

[11] WPSC Response to 02-CSS-01, Audit COSS (PSC REF#: 188206).

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.

The Company's approach misclassifies these capitalized energy costs as demand-related. As a result, the Company's approach over-allocates capitalized energy costs to residential and small C&I rate classes, since these classes have lower load factors than the larger C&I classes.[12]

Q: Have you derived an alternative classification of production plant costs?

A: Yes. I reclassified production plant costs using the "Equivalent Peaker" method, since this method reflects investment decision-making under typical generation expansion planning practices.[13]

I applied the Equivalent Peaker method in two different ways. Under the first approach, I estimate the demand- and energy-related portions of the Company's production plant costs using the Company's forecast of gross plant and non-fuel production costs for the 2014 test year.[14] In this case, I calculated: (1) the average fixed cost per kW-yr for the Company's combustion turbines; and (2) the average fixed cost per kW-yr for the Company's entire generation

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[12] A class with a low load factor (relative to other classes) will be allocated a greater percentage of demand-related costs than that of energy-related costs, because that class's percentage contribution to total system demand is larger than its contribution to total system energy requirement.

[13] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, pp. 52-55.

[14] The Company provided this cost data in its response to Interrogatory 06-CUB/Inter-01 (PSC REF#: 189530).

portfolio.[15] The ratio of (1) to (2) gives the percentage of the Company's production capacity costs that are demand-related under this version of the Equivalent Peaker method.[16]

Using this approach, I estimate that 33% of the Company's production plant costs are demand-related and about 67% are energy-related.

Under the second approach, I estimate the averaged fixed cost per kW-year for the Company's combustion turbines and for the entire generation portfolio based on U.S. Energy Information Administration (EIA) assumptions for the capital and fixed O&M costs for new generic combustion-turbine, combined-cycle, coal, hydro-electric, and wind resources. In this case, I estimated demand-related costs for the total generation portfolio as the product of: (1) the total kW capacity of the Company's generation portfolio; and (2) the EIA estimate of the fixed cost per kW-yr for generic combustion-turbine plant. I then calculated the production plant cost for each of the resources in the Company's portfolio as the product of: (1) the kW capacity for that resource; and (2) the EIA estimate of the fixed cost per kW-yr for that resource type (e.g., coal). I then derived total production plant costs for the Company's generation portfolio by summing the estimated production plant costs for each resource in the portfolio. Finally, I estimated the percentage of the Company's production plant costs that are

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[15] Specifically, I calculated the average fixed cost per kW-year for combustion turbines by summing 2014 test year gross plant cost across all combustion turbines, applying an assumed 10% fixed-charge rate, adding 2014 test year non-fuel production costs for all combustion turbines, and then dividing by the total capacity of the combustion turbines. I calculated the average fixed cost per kW-year for the entire portfolio in the same fashion.

[16] This is a simplified application of the Equivalent Peaker method, since it does not adjust gross plant cost values to account for the timing of the capital expenditures recorded in this cumulative account.

demand-related by dividing demand-related costs for the portfolio by the total production plant costs for the entire portfolio.

Using this approach, I estimate that 31% of the Company's production plant costs are demand-related and about 69% are energy-related.

Q: How does the WPSC COSS over-allocate distribution plant costs to the residential and small C&I classes?

A: The WPSC COSS classifies certain 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 costs. As a result, cost allocations based on minimum-system classifications overstate the appropriate allocation of distribution costs to residential and small C&I customers.[17]

Q: How is the cost of the minimum distribution system generally derived?

A: The most common methods used are: (1) the minimum-size method; or (2) the minimum-intercept method.

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 minimum-intercept method attempts to estimate a functional relationship between equipment cost and equipment size based on the current system, and then to extrapolate that cost function to estimate the cost of equipment that carries zero load (e.g., 0-kVA transformers), the smallest units

[17] Residential and small C&I classes will be allocated a greater percentage of customer-related costs than that of demand-related costs, because the ratio of customers in these classes to total number of customers is larger than the ratio of these classes' demand to total system demand.

legally allowed (e.g., 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The goal of this procedure is to estimate the cost of equipment required to connect existing customers, even if they had virtually no load.

Under either approach, the minimum-system cost is deemed to be customer-related, with the remaining cost classified as demand-related.

Q: Which approach does the Company use to classify distribution costs?

A: According to Ms. Hoffman Malueg, WPSC uses the minimum-size method to classify poles (Account 364), overhead conductors (Account 365), and underground conductors (Account 367). The Company uses the minimum-intercept method to classify line transformers (Account 368).[18]

Q: Do minimum-system 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 approaches are fundamentally flawed because minimum-system costs, however estimated, are neither properly classified as wholly customer-related nor demand-related.[19] 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

[18] All intangible (Account 303), land and land rights (Account 360), structures and improvements (Account 361), distribution substation (Account 362), and underground conduit costs (Account 366) are classified as demand-related. All services (Account 369) and meter costs (Account 370) are classified as customer-related.

[19] 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.

> 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.[20]

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

In addition, the minimum-size and minimum-intercept methods suffer from specific problems that tend to produce unreasonable results. In a 1981 article, George Sterzinger identified a flaw in the minimum-size approach that could result in over-allocation of costs to the residential and small C&I classes.[21] 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 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

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

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

the costs for these larger transformers were not incurred to serve residential load.

The minimum-intercept method avoids the over-allocation problem associated with the minimum-size approach. However, the minimum-intercept method suffers from its own shortcomings. This approach may produce classifications that are not statistically reliable or robust. Moreover, at a conceptual level, the minimum-intercept method is so abstract that its application may not yield realistic results. For example, it may not be appropriate to extrapolate from the current system to estimate the cost of a system that serves zero load. A system designed to connect customers but serve zero load would likely look very different from the existing system. For example, a zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. Without the need for high voltages to carry power, poles could be shorter and cross-arms would be unnecessary; with no transformers and cross-arms, and lighter conductors, poles could be thinner as well. The labor and equipment costs of setting those short, light poles would be much lower than the costs of real utility poles of any size. It is therefore unlikely that a cost estimate based on an extrapolation from the current system would reasonably reflect the cost of an actual zero-load system.

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

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

Q: How would revenue allocations in the WPSC COSS differ if production plant costs were classified based on the Equivalent Peaker method and all distribution plant costs other than meters and services were classified as demand-related?

A: I did not conduct an independent cost of service analysis with these classifications, because it is my understanding that Commission staff will be conducting such an analysis. Since Commission staff's direct testimony is due at the same time as mine, I am reserving the right to supplement on rebuttal my conclusions regarding appropriate allocations of the 2014 test year revenue deficiency following review of Commission staff's filed testimony.

Given my understanding of the likely impacts from appropriate classification of production and distribution plant costs, I expect that Commission staff's analysis will substantially reduce the allocation of the 2014 test year revenue deficiency to residential and small C&I rate classes relative to the WPSC COSS.

IV. Rate Design

Q: What is the Company's proposal with respect to customer charges for residential and small C&I customers?

A: The current customer charges for the residential and small C&I rate classes were established pursuant to the terms of the Energy Efficiency Stipulation approved in Docket No. 6690-UR-119. The Stipulation provided for a reduction in then-prevailing customer charges for all residential and small C&I classes. According to Company witness Mr. Laursen, WPSC proposes to increase customer charges for rural customers to pre-Stipulation levels. In addition, the Company proposes to set customer charges for urban customers equal to those proposed for rural customers, thereby abandoning the long-standing practice of setting rural customer charges higher than urban customer charges. Finally, the Company proposes to move all three-phase residential customers onto small C&I service.

According to Schedule 3 of Ex.-WPSC-Laursen-1, the Company's proposal would increase customer charges for residential and small C&I customers anywhere from 47% to 82%.

Q: What is the basis for the Company's proposal to increase residential and small C&I customer charges?

A: Although couched in terms of residential rates, Mr. Laursen argues generally that increasing the customer charge would create a more equitable rate design, since:

> The cost of the distribution system needed to provide safe, reliable electric service is fixed, but historic rate design for residential customers has sought to recover fixed distribution costs through a variable energy charge. This significantly dilutes the price signal and intensifies rate pressure resulting from decreased sales due to energy efficiency, recession effects, and customer owned generation.[22]

Q: Has Mr. Laursen offered any valid evidence to support his assertion that the current customer charge "dilutes the price signal?"

A: No.[23] In response to Interrogatory No. 3-CUB/Inter-8 (PSC REF#: 187722), Mr. Laursen claims that the price signal from current rates is economically

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[22] Direct-WPSC-Laursen-9, line 6 to Direct-WPSC-Laursen-10, line 2.

[23] The Stipulation precludes CUB from opposing the Company's proposal to increase residential customer charges to pre-Stipulation levels in the event that the RSM is not extended beyond its pilot phase. Since I recommend that the RSM not be extended, the discussion that follows is limited to the Company's arguments as they apply to the proposals to increase residential customer charges above pre-Stipulation levels or to increase small C&I customer charges in general.

inefficient – i.e., that the current energy rate exceeds the economic value of a reduction in customer load – based on the fact that the current energy rate exceeds the Company's forecast for short-run marginal energy cost.[24]

Mr. Laursen's reliance on short-run marginal energy cost as a measure of economic efficiency is not reasonable, since short-run marginal energy cost constitutes only a portion of the full economic value of a reduction in customer load. The economic value of a reduction in customer load is measured not just by short-run marginal energy cost, but by the sum of the long-run distribution, transmission, and generation capital and variable costs avoided by that reduction in load.

Q: Did Mr. Laursen offer any other support for the Company's proposal to increase customer charges?

A: Yes. Mr. Laursen also claims, based on the Company's cost of service study of its estimate of 2014 test year revenue requirements, that:

> … it costs between $31 and $43 per month for WPSC to provide distribution service to a zero use residential customer…. It is not unreasonable for WPSC to appropriately charge customers for the cost of providing service.[25]

In response to Interrogatory No. 3-CUB/Inter-6 (PSC REF #:187720), Mr. Laursen states that his calculation of the cost to serve a "zero use" customer includes both distribution costs classified as customer-related and those classified as demand-related.

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[24] Although Mr. Laursen's response references residential energy rates, his argument would also apply to small C&I energy rates, since small C&I customers pay the same energy rate as residential customers.

[25] Direct-WPSC-Laursen-10, ll. 4-7.

Q: Did Mr. Laursen reasonably estimate the cost to provide distribution service to a "zero use" customer?

A: No. Mr. Laursen's calculation overstates the cost to serve a "zero use" customer by including distribution costs that are classified as demand-related. In other words, Mr. Laursen inappropriately includes in his tally of zero-use distribution costs those costs deemed to be attributable to greater-than-zero demand in Ms. Hoffman Malueg's minimum-system analysis.

In addition, Mr. Laursen's calculation overstates the cost to serve a "zero use" customer, because it includes distribution costs that are misclassified as customer-related in the Company's cost of service studies. As discussed above, the WPSC Audit COSS misclassifies demand-related distribution costs as customer-related by relying on the minimum-system method. As a result, the WPSC Audit COSS overstates the total amount of distribution costs appropriately allocated to the residential and small C&I classes, and overstates the portion of the allocated amount that is appropriately classified as customer-related.

Q: Should all costs appropriately classified in a cost of service study as customer-related be recovered through the customer charge?

A: Not necessarily. While certain costs may be reasonably classified as customer-related for the purposes of cost allocation, that does not imply that those customer-related costs are appropriately recovered 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 customers (with the least-expensive distribution equipment) would be required to pay the average of customer costs attributable to all sizes of customers. In other words, if all customers were to pay the same customer charge regardless of size, then small customers would subsidize larger customers' distribution costs.

Q: Is the Company's proposal to consolidate rate schedules for urban and rural residential and small C&I customers reasonable?

A: Yes. As discussed by Mr. Laursen, the differences between urban and rural customer-related costs appear too inconsequential to justify the additional cost and resources needed to maintain separate rate schedules.

However, as discussed above, the Company has not reasonably supported its proposal to increase the residential urban charge to the level charged to rural customers prior to implementation of the Stipulation. Likewise, the Company has not offered a reasonable basis for increasing either small C&I urban or small C&I rural charges to the pre-Stipulation rural rate.

Q: Is the Company's proposal to move residential three-phase customers onto small C&I service reasonable?

A: Yes. However, as discussed above, the Company has not reasonably supported its proposal to increase both urban and rural small C&I customer charges for three-phase service to the levels charged to rural customers prior to implementation of the Stipulation.

Q: What do you recommend with regard to the Company's proposal to increase customer charges for the residential and small C&I rate classes?

A: The Company lacks a reasonable basis for its proposal to increase residential urban customer charges to the rate charged to residential rural customers prior to implementation of the Stipulation. Moreover, the Company lacks a reasonable basis for its proposal to increase small C&I charges for both urban and rural customers to the rural rate prevailing prior to the Stipulation. Consequently, the Commission should reject those elements of the Company's proposal.

Instead, and presuming the Commission rejects the Company's proposal to extend the RSM, I recommend that customer charges be set as follows:

Residential Urban Single-Phase	Increase to pre-Stipulation rate of $8.40.
Residential Rural Single-Phase	Increase to $8.40 to allow for consolidation with urban rate schedule.
Residential Urban Three-Phase	Increase to $10.25 to allow for transfer to small C&I rate schedule.
Residential Rural Three-Phase	Decrease to $10.25 to allow for transfer to small C&I rate schedule.
Small C&I Urban Single-Phase	Increase to current rural rate of $8.50 to allow for consolidation with rural rate schedule.
Small C&I Rural Single-Phase	Maintain at current rate of $8.50.
Small C&I Urban Three-Phase	Maintain at $10.25.
Small C&I Rural Three-Phase	Decrease to $10.25 to allow for consolidation with urban rate schedule.

In summary, I recommend that customer charges be set as shown in Table 2.

Table 2. 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%)

In the event that the Commission extends the RSM, I recommend that customer charges be set as shown in Table 3.

Table 3. Proposed Monthly Customer Charges with RSM Extension

	Current Charge	Proposed Charge	Percent Change
Rg-1, 3, 5 Single Phase	$5.70	$5.70	0.0%
Rg-2, 4, 6 Single Phase	$7.00	$5.70	(18.6%)
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	$7.25	0.0%
Cg-2, 4 Single Phase	$8.50	$7.25	(14.7%)
Cg-1, 3 Three Phase	$10.25	$10.25	0.0%
Cg-2, 4 Three Phase	$11.50	$10.25	(10.9%)

Q: What do you recommend with regard to allocation of the 2014 test year revenue deficiency and the design of residential and small C&I rates?

A: I will recommend specific revenue allocations and rate designs as part of my rebuttal testimony, once I have had the opportunity to review and evaluate Commission staff's cost of service studies. These rates will be designed to achieve the following objectives:

- Set rates for individual rate classes within a major customer group (i.e., Energy Only; Optional Time-of-Use) to achieve the recommended allocation of 2014 test year revenue requirements for the group as a whole.
- Set rates for individual rate classes within a major customer group to reflect the relative allocations among these rate classes in the Staff COSS.
- Set customer charges as shown in Table 2, above.

Q: Does this complete your direct testimony?

A: Yes.