BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	)))	 Docket No. 6690-UR-123

DIRECT TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
August 13, 2014

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 before the Public Service Commission (PSC or the Commission) in Docket Nos. 6630-CE-302, 3270-UR-117, 4220-UR-117, 6680-FR-104, 3270-UR-118, 05-UR-106, 4220-UR-118, 6690-UR-122, and 4220-UR-119. 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 April 1, 2014, Wisconsin Public Service Corporation (WPSC or "the Company") filed an application to increase electric and gas rates for the 2015 test year. The Company subsequently filed additional supporting testimony on May 15, 2014. This testimony addresses the following aspects of the Company's filing:

- The methods used by WPSC in its electric cost of service study (COSS) to allocate the proposed 2015 test year electric revenue deficiency to the residential and small commercial and industrial (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 proposal to increase the residential and small C&I

customer charges, as described in the pre-filed direct testimony of Company witnesses Ronda L. Ferguson and Russell T. Laursen.

- The need to move beyond the Company's narrow proposals for rate restructuring in light of fundamental changes overtaking the electric utility industry.

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

A: The Company is requesting that electric rates be increased on average by 8.0% in order to recover an expected revenue deficiency of $76.8 million in the 2015 test year. Based on the results of a single cost of service study, WPSC proposes to allocate $35.7 million to residential and small C&I customers. This amount represents a 7.5% increase over residential and small C&I revenues under current rates.

The Company's cost of service study overstates the portion of the $76.8 million revenue deficiency appropriately allocable to the residential and small C&I classes, 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 staff audit finds a revenue deficiency for the 2015 test year of $28.7 million, or about 2.9% of 2015 test year electric revenues under current rates. At the request of Commission staff, WPSC conducted four cost of service studies based on the Commission staff audit forecast of 2015 test year revenue requirements. These four studies differ with respect to the methods used to classify production and distribution plant costs, as well as with respect to the treatment of interruptible credits. All four studies show a revenue excess for the residential and small C&I classes, indicating that average residential and small C&I rates for the 2015 test year should be reduced from current levels.

For the purposes of allocating the overall revenue deficiency to customer classes and setting rates for the 2015 test year, it would be appropriate to consider the results of all four of the audit cost of service studies. To varying degrees, all four studies indicate that it would not be reasonable to increase residential and small C&I rates in the 2015 test year. I intend to offer my proposed recommendation for allocation of the 2015 test year revenue deficiency in rebuttal testimony.

Q: Please summarize your findings and recommendations with regard to rate design for the residential and small C&I classes.

A: The Company lacks a reasonable basis for its proposal to shift costs from the energy charge to the customer charge (renamed the "fixed" charge by WPSC). Redesigning residential and small C&I rates in the fashion proposed by WPSC would inappropriately shift load-related costs to the fixed charge, dampen and destabilize 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. An increase in fixed charges for residential and small C&I customers would be especially inappropriate at this time, in light of the fact that these customers are due a rate decrease in test-year 2015. It would be unfair to increase small customers' bills while other consumers enjoy stable or even lower bills. Consequently, the Commission should reject the Company's proposals to increase the fixed charge from $10.40/month to $25.00/month for residential customers and from $12.50/month to $35.00/month for small C&I customers.

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 my recommendation to maintain fixed charges at current levels.

Q: Are you suggesting that increases to residential and small C&I fixed charges would never be warranted?

A: Not at all. As the Commission has recognized, the electric utility industry is undergoing rapid changes due to customers' growing embrace of, and demand for, distributed renewable technologies. The Company's (and other Wisconsin utilities') initial reaction to these changes has been defensive: radically restructuring rates in order to counteract a "disruptive" threat to earnings. Yet, such narrowly tailored, defensive strategies may ultimately prove counter-productive, since the success of such strategies depends on frustrating customers' desire for distributed generation.

While inadequate in isolation, rate restructuring could prove to be a key component of a broader, more comprehensive strategy for adapting in an evolving industry. Such a strategy should be built around the core notions that: (1) distributed generation can provide value to *all* customers, regardless of whether they have distributed resources on their premises; and (2) distributed generation can be a source of value to *both* shareholders and customers.

The Commission should direct the Company to work with interested parties to develop regulatory policies and business strategies that accommodate the changes overtaking the industry. This process should consider the regulatory, planning, investment, and financial implications of a rapid growth in distributed generation. The goal would be to develop for implementation in 2016 a package of regulatory policies, planning procedures, investment strategies, and rate designs that:

- Provide ratepayers with reliable, least-cost, low-risk, and sustainable electricity service;
- Reduce barriers to the adoption of cost-effective distributed renewable resources;
- Ensure that all consumers, regardless of income level, share in the benefits of distributed generation; and
- Provide for the Company's continued financial viability.

II. WPSC Cost Allocation

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

A: The Company is requesting that electric rates be increased on average by 8.0% in order to recover an expected revenue deficiency of $76.8 million in the 2015 test year. Of the total $76.8 million requested revenue increase, WPSC proposes to allocate $35.7 million to residential and small C&I customers.[1] This amount represents a 7.5% increase over residential and small C&I revenues under current rates.

Q: What is the basis for the proposed revenue allocation to residential and small C&I customers?

A: According to Mr. Laursen, the Company relied on a single cost of service study ("WPSC COSS") to develop its proposal for allocating the $76.8 million revenue deficiency to the customer classes. This cost of service study shows a revenue deficiency of about $34.3 million for residential and small C&I

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

customers.[2] This amount represents a 7.2% increase over residential and small C&I revenues under current rates.

Q: Does the WPSC COSS reasonably allocate the revenue deficiency to customer classes?

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

A. Allocation of Production Plant Costs

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

A: The WPSC COSS classifies all production plant costs as demand-related, implying that, from a generation planning perspective, production plant costs are incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy 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

[2] Ex.-WPSC-Laursen-1, Schedule 2.

these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.[3] Consequently, if a utility's generation portfolio contains intermediate and baseload generating units that are more expensive than peaking plants (as is the case for WPSC), it is not appropriate to classify production plant costs for those intermediate and baseload plants as 100% demand-related and 0% energy-related. Doing so over-allocates such capitalized energy costs to residential and small C&I rate classes, since these classes have lower load factors than the larger C&I classes.[4]

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

A: I have not, since it is my understanding that Commission staff derived an alternative classification based on the "Equivalent Peaker" method for the purposes of allocating audit revenue requirements. Commission staff's approach to classifying production plant costs is appropriate, since the Equivalent Peaker method reflects investment decision-making under typical generation expansion planning practices.[5]

---

[3] The amount of capitalized energy costs that should be classified as energy-related can be determined using the "Equivalent Peaker" method. See National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, pp. 52-55.

[4] 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.

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

B. Allocation of Distribution Plant Costs

Q: Which aspects of the WPSC COSS lead to over-allocation of distribution plant costs to the residential and small C&I classes?

A: The WPSC COSS misallocates distribution plant costs by:

- Classifying certain distribution costs as customer-related or demand-related based on a minimum distribution system analysis.
- Assuming a 50%-50% split of the costs of primary-voltage poles, overhead wires, and underground wires between three-phase circuits and single-phase circuits, and then separately allocating or assigning three-phase and single-phase costs between primary and secondary customers.

1. Minimum Distribution System Classification

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-size approach attempts to estimate the cost to exactly replicate the configuration of the existing distribution system using the smallest-size equipment currently used on the 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 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, assuming they have virtually no load.

Under either approach, the minimum distribution 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 Company witness 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).[6]

Q: Do minimum distribution system analyses generally produce reasonable classifications of costs?

A: No. The minimum distribution system approach is fundamentally flawed, since it is premised on a simplistic model of cost causation that is inconsistent with typical distribution-system planning, design, and investment practices. Where distribution-system costs may be driven by a host of design considerations – such as customer load, load growth, terrain, customer density, voltage considerations, or minimum service reliability and quality requirements – the minimum distribution system approach simplistically models cost-causation as a function of just two factors: customer load and number of customers. As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, with only two explanatory variables driving cost-

---

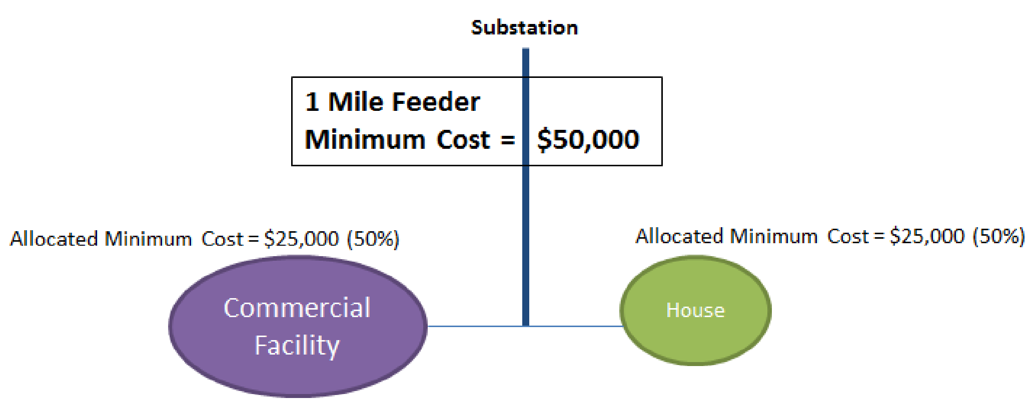
[6] All intangible (Account 303), land and land rights (Account 360), structures and improvements (Account 361), distribution substation (Account 362), and underground conduit costs (Account 366) are classified as demand-related. All services (Account 369) and meter costs (Account 370) are classified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

causation, minimum distribution system models classify as customer-related all costs not directly driven by demand, regardless of whether such costs are related to the number of customers:

> 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.[7]

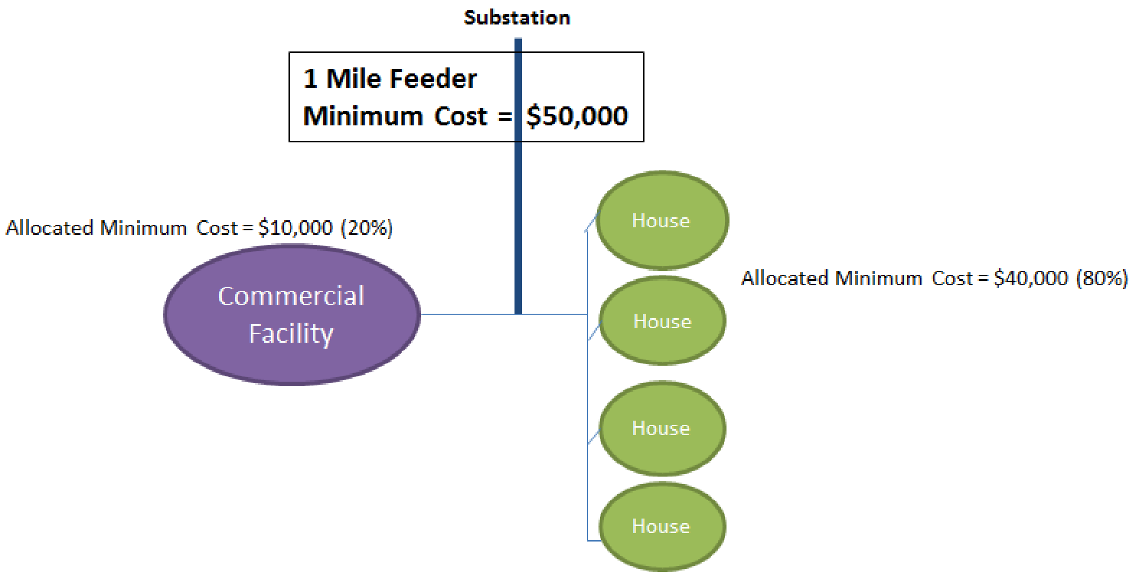
The examples shown in Figures 1a and 1b illustrate this basic flaw in the minimum distribution system approach. In the example shown in Figure 1a, a hypothetical distribution system consists of a single one-mile feeder serving two customers: a commercial facility and a single-family home. In Figure 1b, the same hypothetical one-mile feeder serves the same commercial facility and four single-family homes.

Figure 1a



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

Figure 1b



As indicated in these figures, the minimum cost of the single feeder is the same in both examples, even though the number of customer accounts varies (2 in Figure 1a; 5 in Figure 1b). The minimum cost does not vary with the number of customer accounts in these examples because by definition it is the cost of the minimum-sized feeder equipment required to connect these customers regardless of the total load on the feeder. In other words, the addition of three homes does not increase the minimum cost of the feeder. Yet, even though the minimum cost is **not** driven by customer number, the minimum distribution system approach allocates minimum costs between the residential and commercial classes as if such costs did vary with customer number. In the example shown in Figure 1a, 50% of the minimum cost would be allocated to the residential class. In contrast, in the example shown in Figure 1b, 80% of the same minimum cost would be allocated to the residential class. Thus, the minimum distribution system approach does not allocate costs consistently with cost-causation.

Residential and small C&I customers are especially burdened because these non-customer-related minimum costs are arbitrarily classified as customer-related rather than demand-related. These 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.

Q: Are there other problems with the minimum distribution system method?

A: Yes. Both the minimum-size and minimum-intercept methods suffer from specific problems that tend to over-allocate distribution plant costs to the residential and small C&I customer classes.

In a 1981 article, George Sterzinger identified a flaw in the minimum-size approach that could overstate the appropriate allocation of demand-related costs to the residential and small C&I classes.[8] The problem arises because the minimum-size method typically defines the minimum system to include equipment that is large enough to cover the average load of residential customers.[9] In that event, only those costs incurred for the minimum-size equipment, deemed to be customer-related, are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method not only allocates to the residential class the cost for the minimum-size equipment as customer-related, but also inappropriately allocates to residential customers a portion of the actual equipment costs in excess of the minimum-size

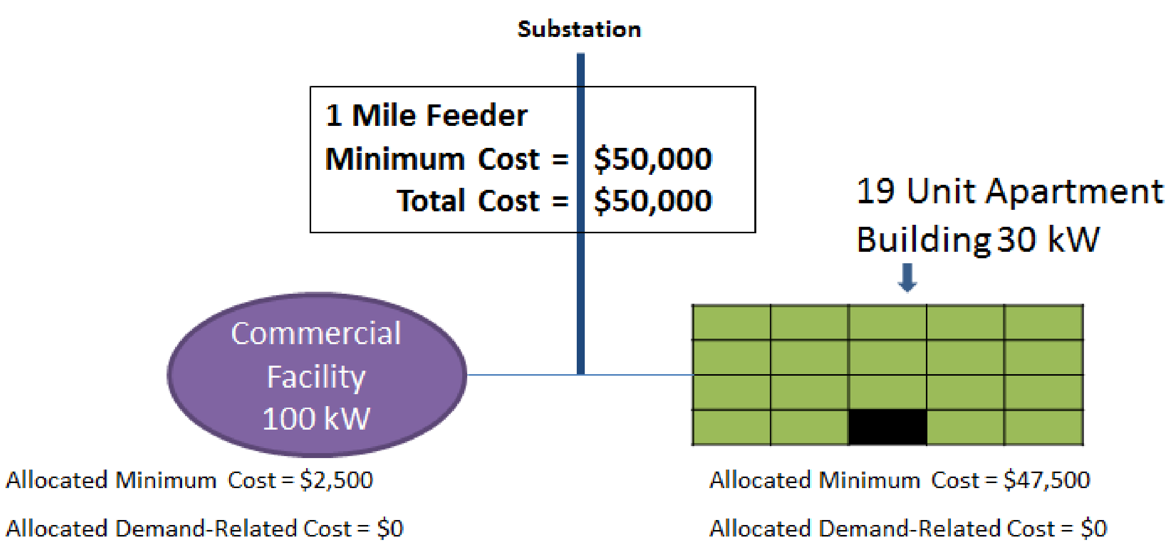
[8] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, July 2, 1981.

[9] In other words, the utility would not have installed equipment that is larger and more-expensive than the minimum-size equipment if it were only serving residential load.

costs as demand-related costs, even though these excess costs were not incurred to serve residential load.

Figures 2a and 2b illustrate this problem of over-allocation of demand-related costs when using the minimum-size method. As in Figures 1a and 1b, Figures 2a and 2b assume a hypothetical distribution system consisting of a single one-mile feeder. In the example shown in Figure 2a, there are 20 customers served by the feeder: 19 units in an apartment building with a combined load of 30 kW and a single commercial facility with a load of 100 kW. In this case, the minimum-size feeder is assumed to be large enough to cover the combined load on the system, meaning that the minimum cost is equal to the total cost of the feeder. Consequently, under the minimum-size approach, 100% of the total cost of the feeder is classified as customer-related and the residential class (with 19 of the 20 customer accounts served by the hypothetical distribution system) is allocated 95% of this customer-related cost.[10]

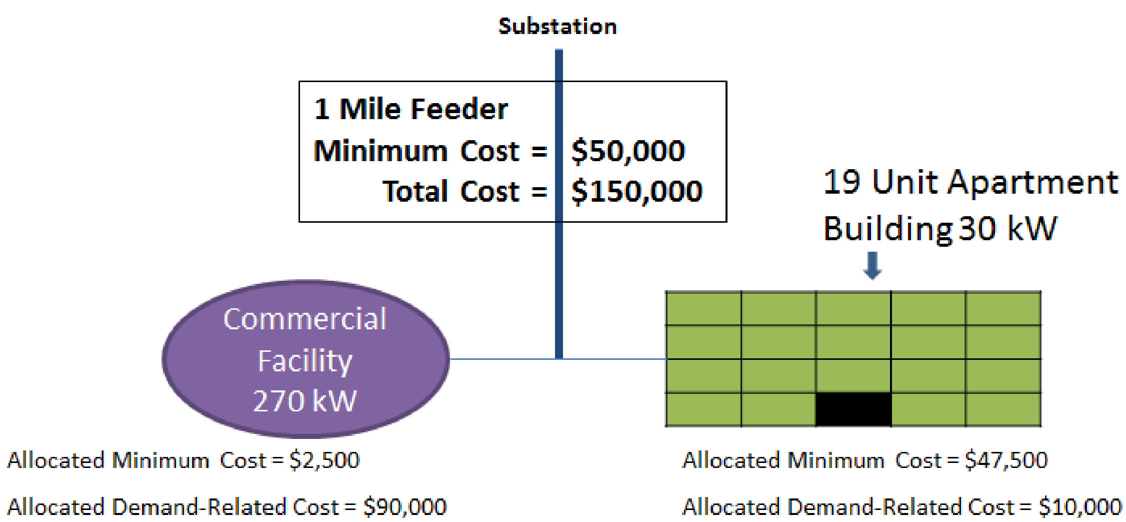
Figure 2a



[10] As discussed above with regard to Figures 1a and 1b, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

The example shown in Figure 2b assumes the same number of customers as in Figure 2a. However, in this example, the commercial facility has a load of 270 kW, requiring a larger feeder. As in Figure 2a, the residential class would be allocated 95% of the minimum cost of the feeder. Unlike the case in Figure 2a, however, the residential class would also be allocated 10% of the demand-related feeder costs – those costs in excess of the cost of a minimum-size feeder – even though such costs would not have been incurred without the additional commercial load on the system. Instead, all such excess costs in this example should be allocated to the commercial class.

Figure 2b



Q: Does the minimum-intercept method also suffer from this problem?

A: No. The minimum-intercept method avoids this over-allocation of demand-related costs by setting minimum cost at the estimated cost for a system with zero load.[11]

[11] In contrast with the minimum-size approach, which sets the minimum cost at the cost of the minimum-size equipment used by the utility, where such minimum-size equipment may be large enough to cover average residential load.

However, 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. If so, then the minimum-intercept approach would misclassify demand-related costs as customer-related and thereby over-allocate distribution plant costs to the residential and small C&I classes.

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

A: Yes. A reasonable and reasonably straightforward approach, and one that has been used in other jurisdictions, is to classify meters and services as customer-related and all other distribution plant costs as demand-related.[12]

Alternatively, distribution plant costs (other than meters and services) could be classified using the approach adopted by Wisconsin Electric Power

[12] According to a study by the Regulatory Assistance Project, this approach is employed in more than thirty states. See Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, December, 2000, p. 30.

Company (WEPCO). Recognizing that minimum-sized equipment is designed to carry load, WEPCO classifies 50% of minimum-system costs as demand-related and 50% as customer-related.[13] Under this approach, for example, if minimum-system cost were 50% of total distribution plant cost, then 75% of total cost would be classified as demand-related and 25% would be classified as customer-related.

2. Three-Phase / Single-Phase Cost Allocation

Q: How does WPSC allocate primary-voltage distribution plant costs between primary and secondary customers?

A: The Company assumes for cost-allocation purposes that 50% of the costs of primary-system poles, overhead wires, and underground wires are attributable to three-phase service and 50% of the costs are attributable to single-phase service. The Company then assigns 100% of the assumed single-phase costs to secondary customers, since primary customers do not take single-phase service. The assumed three-phase costs are classified and allocated among all primary and secondary customer classes using the minimum-size method.

This method of allocating primary-voltage distribution plant costs differs from the approach used in Docket No. 6690-UR-122. In that proceeding, WPSC did not assume a three-phase / single-phase split in primary costs, and instead allocated all primary costs among primary and secondary customer classes using the minimum-size method.

Q: Why did the Company modify its approach in the instant proceeding?

[13] See Direct-WEPCO/WG-Rogers-20, ll. 14-17 (Docket No. 05-UR-107) (PSC REF#: 208199).

A: According to Ms. Hoffman Malueg, WPSC agreed with a proposal by the Wisconsin Industrial Energy Group (WIEG) in Docket No. 6690-UR-122 to assume a 50%/50% three-phase / single-phase split.

Q: Why didn't WPSC adopt the WIEG proposal in Docket No. 6690-UR-122?

A: According to Ms. Hoffman Malueg's rebuttal testimony in that case, while the WIEG proposal appeared reasonable for overhead and underground wire costs, the Company wanted to investigate further whether it would be reasonable for pole and underground conduit costs. Consequently, WPSC committed to study this issue and then implement the WIEG proposal where appropriate in the next general rate case.[14]

Q: Did the Commission approve the adoption of the WIEG proposal in Docket No. 6690-UR-122?

A: No. Citing concerns raised by Commission staff, the Commission concluded that:

> WIEG's analysis of primary-voltage distribution system costs and cost causation is insufficient, and as such WIEG's proposed primary-voltage distribution allocation method does not merit adoption at this time. Given the information presented in the record, and recognizing the limits of the way WPSC currently tracks distribution asset costs, the Commission finds the method used by WPSC in this proceeding to allocate primary-voltage distribution circuit costs to be reasonable, and finds it unnecessary at this time to order WPSC to perform additional study.[15]

Specifically, the Commission cited the staff's concern that:

[14] Rebuttal-WPSC-Hoffman Malueg-16, ll. 7-11 (Docket No. 6690-UR-122) (PSC REF#: 190654).

[15] Final Decision, Docket No. 6690-UR-122, December 18, 2013, pp. 47-48 (PSC REF#: 194645).

> … in focusing on the extent to which the single-phase primary distribution system does or does not provide system benefits to primary voltage customers, WIEG's analysis fails to consider whether there are portions of the three-phase primary voltage system that provide more benefits to primary customers than secondary voltage customers.[16]

Although the Commission rejected its proposal, it encouraged WIEG to work with the Company and other interested parties to:

> … perform additional analysis in order to remedy the defects identified in this proceeding. Specifically, the Commission would like the interested parties to work with WPSC to determine what portion of the three-phase system was caused to be built by secondary customers, and whether and what amount primary customers benefit from the single-phase system.[17]

Q: Did WPSC evaluate Commission staff's concerns, as requested by the Commission?

A: CUB is not aware of any meetings between WPSC and interested parties to address Commission staff's concerns.

Q: Is Commission staff's concern valid?

A: Yes. The problem with the Company's approach is that it fails to consider whether primary-voltage customers may be responsible for a greater share of three-phase costs than would be indicated under a minimum-system allocation. For example, according to WPSC Response to 06-CUB/Inter-9 (PSC REF#:213168), the three-phase costs allocated to both primary and secondary customers include costs associated with three-phase equipment that serves only primary customers.[18] As such, the Company's allocation approach inappropriately allocates to secondary customers three-phase costs that were incurred solely for the purposes of serving primary customers.

---

[16] *Id.*, p. 47. CUB raised similar concerns in its rebuttal testimony in that proceeding.

[17] *Id.*, p. 48.

[18] A copy of this response is attached as Ex.-CUB-Wallach-2.

Q: What do you recommend with regard to the Company's method for allocating primary-voltage distribution plant costs?

A: As it did in 6690-UR-122, the Commission should reject any method that attempts to segregate three-phase from single-phase primary costs for the purposes of cost allocation. Instead, the Commission should again request that WPSC engage with interested parties to investigate the extent of primary customers' responsibility for three-phase primary costs.

III. Staff Audit Cost Allocation

Q: What does the Commission staff audit find with regard to the expected revenue deficiency for the 2015 test year?

A: The Commission staff audit finds a revenue deficiency for the 2015 test year of $28.7 million, or about 2.9% of 2015 test year electric revenues under current rates.[19]

Q: Did WPSC conduct cost of service studies based on Commission staff audit revenue requirements?

A: Yes. At the request of Commission staff, WPSC conducted four cost of service studies based on the Commission staff audit forecast of 2015 test year revenue requirements.[20] These four studies differ with respect to the methods used to classify production and distribution plant costs, as well as with respect to the treatment of interruptible credits:

- The "UR-122 COSS" adopts the Company's approach for classifying production and distribution plant costs. As I discuss above, WPSC

[19] WPSC Response to 04-CSS-01 (PSC REF#: 212807).

[20] *Id.*

classifies all production plant costs as demand-related and classifies distribution plant costs as customer- or demand-related on the basis of a minimum distribution system analysis. The UR-122 COSS also adopts the Company's approach of allocating demand-related production plant costs on the basis of class load net of interruptible load. However, the UR-122 COSS does not adopt the method used in the WPSC COSS to segregate and allocate three-phase and single-phase primary distribution plant costs. Instead, the UR-122 COSS uses the Company's method from Docket No. 6690-UR-122.

- The "Capacity COSS" modifies the treatment of interruptible load in the UR-122 COSS. Specifically, the Capacity COSS allocates demand-related production plant costs on the basis of gross class load, but explicitly credits interruptible load at Commission staff's estimates of the class revenue requirement credits for interruptible and direct load control capacity.
- The "Time-of-Use (TOU) COSS" modifies the Capacity COSS by classifying 40% of production plant costs as demand-related and the remaining 60% as energy-related. My understanding is that this demand/energy split is based on the results of Commission staff's Equivalent Peaker analysis.
- The "Locational COSS" modifies the TOU COSS by classifying all distribution plant costs, other than for meters and services, as demand-related.

Q: Please describe the results of the four Commission staff audit cost of service studies.

A: As noted above, based on Commission staff's audit, the revenue deficiency for the 2015 test year is about $28.7 million, or about 2.9% of 2015 test year electric revenues under current rates. For each of the four cost of service studies, Table 1 shows the allocation of this overall deficiency to each of the major customer classes, expressed as a percentage of 2015 test year electric revenues under current rates for each class.

As indicated in Table 1, all four of the audit cost of service studies show a revenue *excess* for residential and small C&I customers, ranging from negative 0.1% in the UR-122 COSS to negative 8.4% in the Locational COSS. On average across the four studies, the revenue excess for residential and small C&I customers is negative 3.0%.[21]

Table 1: Staff Audit COSS Revenue Deficiency (% of Current Revenues)[22]

`	UR-122 COSS	Capacity COSS	TOU COSS	Locational COSS	Average
Residential and Small C&I	-0.1%	-0.6%	-2.9%	-8.4%	-3.0%
12,500-25,000 kWh	-7.5%	-8.2%	-10.7%	-3.8%	-7.5%
Medium C&I	9.5%	9.1%	8.0%	15.2%	10.5%
Large C&I	7.2%	8.5%	14.5%	18.5%	12.2%
Lighting & Misc.	-33.5%	-33.8%	-33.6%	-37.1%	-34.5%
Total System	2.9%	2.9%	2.9%	2.9%	

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

[21] In other words, current residential and small C&I rates would need to be reduced on average by 3.0% to eliminate the excess of 2015 test year revenues under current rates over 2015 test year revenue requirements.

[22] The results for the Locational COSS understate the revenue excess for the residential and small C&I classes, because of an apparent computational error in the Locational COSS spreadsheet. Specifically, the Locational COSS incorrectly classifies a portion of Account 368 (secondary transformer) plant costs as customer-related. As requested by the Commission staff, the Locational COSS should have classified all Account 368 costs as demand-related.

A: Of the four studies, the Locational COSS classifies and allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs because it corrects for the Company's misclassification of production plant costs as 100% demand-related and corrects for the inappropriate use of the minimum distribution system method for classifying distribution plant costs.

However, for the purposes of allocating the overall revenue deficiency to customer classes and setting rates for the 2015 test year, it would be appropriate to consider the results of all four studies. To varying degrees, all four studies indicate that it would not be reasonable to increase residential and small C&I rates in the 2015 test year.

Q: Do you have a recommendation for allocating the Commission staff audit revenue deficiency to customer classes?

A: Not at this time. My understanding is that, as part of its direct filing, Commission staff will be adjusting the results of the four cost of service studies to reflect the treatment of Revenue Stabilization Mechanism credits adopted by the Commission in Docket No. 6690-UR-122. I anticipate proposing a revenue allocation and rate design as part of my rebuttal testimony, once I have had the opportunity to review the Commission staff's adjustments.

IV. Rate Design

Q: What is the Company's proposal with respect to residential and small C&I rate design?

A: According to Company witness Ms. Ferguson, WPSC proposes a radical restructuring of residential and small C&I rates in order to shift recovery of allegedly "fixed" costs from the energy charge to the customer charge.

Specifically, WPSC proposes to dramatically increase the monthly "fixed charge" for residential customers from $10.40 to $25.00, or about 140%.[23] The Company proposes an even sharper increase in the monthly fixed charge for small C&I customers from $12.50 to $35.00, or 180%.[24] To accommodate these steep increases to monthly fixed charges, WPSC proposes to reduce the energy charge for Rg-1 customers by 10.4% and for Cg-1 customers by 13.3%.

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

A: According to Ms. Ferguson, the fixed charge would have to increase to $66.20 per month, or by more than six times the current level, in order to recover all costs allocated to the residential class under the WPSC COSS that the Company considers to be "fixed."[25]

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

A: If the fixed charge for the Rg-1 rate class were increased to $66.20 per month, the energy charge would have to be reduced dramatically from about 11.3¢/kWh to about 3.1¢/kWh.[26]

Q: Is the Company proposing to increase the fixed charge to recover all allegedly "fixed" costs?

---

[23] Direct-WPSC-Ferguson-6, table at line 1. The Company also proposes to rebrand the customer charge as the "fixed charge." See, e.g., Ex.-WPSC-Laursen-1, Schedule 14, p. 8.

[24] Ex.-WPSC-Laursen-1, Schedule 3.

[25] Direct-WPSC-Ferguson-3, table at line 6.

[26] This calculation is based on the revenue allocation to the Rg-1 rate class reflected in Ex.-WPSC-Laursen-1, Schedule 3.

A: Not at this time. However, the Company's rationale for its proposal in Docket No. 6690-UR-122 to raise the residential customer charge to $10.40 is similar to its rationale in the instant proceeding to support a further increase from $10.40 to $25.00. It is not hard to imagine the Company arguing for further shifting of "fixed" costs from the energy charge to the fixed charge in future rate proceedings.

Q: What are the "fixed" costs that WPSC proposes to recover through the residential and small C&I fixed charges?

A: According to Ms. Ferguson, "fixed costs are the expenses that WPSC incurs to provide service to a customer regardless of the amount of energy the customer consumes."[27] This includes not only costs that are classified as customer-related in the WPSC COSS, but also all costs (whether generation, transmission, or distribution) classified as demand-related. Thus, from the Company's perspective, the only non-fixed costs are those that are classified in the WPSC COSS as energy-related, which are predominantly fuel and variable O&M costs.

Based on the results of the WPSC COSS, I estimate that the "fixed" demand-related costs constitute about 55% of Ms. Ferguson's estimate of the total "fixed" cost for Rg-1 customers.[28]

Q: Would it be reasonable to recover all costs classified in the WPSC COSS as customer-related through residential and small C&I fixed charges?

A: No. As discussed above, the WPSC COSS misclassifies demand-related distribution costs as customer-related by relying on the minimum distribution

---

[27] Direct-WPSC-Ferguson-2, ll. 15-16.

[28] See the worksheet 'RATESEP-RG-1' of 'UR123_Elec_COSS_Filing Version_1P3P_Electronic.xlsx', provided in WPSC Response to 02-CUB/RFP-06 (PSC REF #: 206879).

system method. As a result, the WPSC 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 amounts that are appropriately classified as customer-related. In fact, the Locational COSS shows that fixed charges for the Rg-1 and Cg-1 classes would be half of what the Company is proposing, if such charges were set to recover all costs reasonably classified as customer-related. Specifically, the Locational COSS shows customer-related costs of $13.77 per month for Rg-1 and $16.35 per month for Cg-1.[29]

In addition, it would not be appropriate to recover through fixed charges the full $13.77 per month and $16.35 per month deemed to be customer-related in the Locational COSS. While it may be reasonable to classify certain costs as customer-related for the purposes of allocating such costs among customer classes in a cost of service study, it is not appropriate to recover all such costs allocated to the residential and small C&I classes through a fixed 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 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 fixed charge regardless of size, then small customers would subsidize larger customers' distribution costs.

[29] See the worksheets 'RATESEP-RG-1' and 'RATESEP-CG-1' of 'UR123_Elec_COSS_AUD Exc ICE_Standard_Electronic_Locational.xlsx', provided in WPSC Response to 04-CSS-01 (PSC REF #: 212807). As discussed in footnote 22, the Locational COSS overstates the amount of customer-related costs.

Q: Would it be appropriate to recover demand-related costs through fixed charges?

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 in any year is unlikely to vary much with load or sales in that year.[30]

However, from the longer-term perspective of cost-causation and price signals, plant investments and fixed O&M are variable with respect to customer demand. Shifting recovery of such demand-related costs to the fixed 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.[31]

Q: Why is WPSC proposing to radically redesign residential and small C&I rates at this time?

A: Ms. Ferguson offers the following reasons for restructuring residential and small C&I rates:

[30] This may not even be the case for demand-related transmission costs. My understanding is that the bulk of these costs are attributable to ATCLLC and MISO network transmission charges and fees. As such, these costs are not fixed, even in the short-term, but vary with system demand or energy.

[31] In fact, the Company’s proposal could further and needlessly increase fixed charges, in order to recover uneconomic plant investment required to meet demand growth resulting from misleading price signals.

> Aligning fixed and variable rates with the costs that they are intended to recover will lead to better and more efficient outcomes for both WPSC and its customers by (1) reducing the volatility in WPSC's revenues due to extreme weather or economic conditions, (2) creating more stable customer bills and sensible price signals for consumers seeking to invest in energy efficiency, energy conservation measures or distributed generation, and (3) reducing the cross-subsidization between customers within the same rate class.[32]

I address each rationale in turn.

Q: Why is the Company concerned about revenue volatility?

A: According to Ms. Ferguson, the Company is not concerned about revenue volatility per se, but the adverse impact on earnings when actual sales in a test year are less than forecasted for that test year. In general, rates are set to recover forecasted costs and an authorized return based on a forecast of energy sales for a future test year. To the extent that sales are lower than forecast, and to the extent that the resulting reduction in energy revenues exceeds the reduction in variable costs, the Company's earned return will fall below the authorized return.

Q: Why would increasing the fixed charge reduce the earnings impact from lower-than-forecast sales?

A: An increase in the fixed charge, and consequent decrease in the energy charge, would reduce the gap between energy revenues and variable costs and thus reduce the earnings shortfall when actual sales are less than forecasted. In other words, an increase in the fixed charge would stabilize earnings in the same fashion as under the Company's former Rate Stabilization Mechanism pilot.[33]

---

[32] Direct-WPSC-Ferguson-7, ll. 21-27.

[33] As with the Rate Stabilization Mechanism, the Company could eliminate sales-related earnings risk by shifting all demand-related costs from the energy charge to the fixed charge. As I

Q: Has the Company been adversely affected by lower-than-forecast sales in the recent past?

A: Not from residential sales. To the contrary, actual annual residential sales from 2011 through 2013 have exceeded forecasted sales for the test years 2011 through 2013 by 2% to 8%.[34]

Q: Would the Company's proposed rate restructuring dampen variations in consumer bills?

A: Yes. However, such a restructuring would mitigate bill increases when ratepayers least need mitigation and limit bill reductions when ratepayers need bill reductions the most.

All else equal, a higher fixed charge and lower energy charge would decrease the amount by which actual electricity costs will be higher than forecast for the test year when, for example, strong economic growth has increased consumption. While the higher fixed charge dampens 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 Company's proposed rate restructuring would moderate the decline in energy spending at a time when ratepayers incomes are falling, thereby making electricity service increasingly unaffordable.

Q: Why is the Company concerned about stabilizing customer bills?

A: According to Ms. Ferguson, the Company is concerned that recovering allegedly fixed costs through the energy charge will cause confusion among customers:

---

discuss above, shifting all demand-related costs would increase the fixed charge to $66.20/month and reduce the energy charge to 3.1 ¢/kWh.

[34] Based on data provided in WPSC Response to 02-CUB/Inter-14 (PSC REF#: 206207).

> …when fixed costs are recovered through variable charges, reduced sales increase the need for WPSC to request rate increases to recover its revenue deficiency. This is confusing for customers who invest in energy efficiency or energy conservation measures, only to see their rates increase. Customers expect their conservation efforts to reduce their energy costs, but are confused when they see WPSC seeking rate increases due to conservation. This confusion could ultimately discourage energy conservation.[35]

Q: Is the concern about customer confusion valid?

A: Such a concern is valid in general, but misplaced in this case, since reduced sales and under-recovery of fixed costs do not appear to be driving the increase over test-year 2014 residential rates. Instead, the increase appears to be largely due to an increase in the unit (i.e., per kWh) cost of fuel and variable O&M costs. In other words, the increase in rates from test-year 2014 are apparently not "due to conservation," but due to an increase in variable energy costs.

Table 2 shows for the test-years 2014 and 2015 the energy-, demand-, and customer-related costs allocated to the Rg-1/Rg-2 class on a per kWh basis.[36] As indicated in Table 2, only energy-related costs per kWh have increased from the 2014 to the 2015 test year. In contrast, demand- and customer-related costs per kWh have declined slightly from 2014 to 2015.

---

[35] Direct-WPSC-Ferguson-9, ll. 3-9.

[36] Tabular data for test-year 2015 are based on the results of the UR-122 COSS in the instant proceeding. Tabular data for test-year 2014 are based on the results of the comparable Commission staff audit cost of service study in Docket No. 6690-UR-122.

Table 2: Staff Audit Expenses Allocated to Rg-1 / Rg-2 Customers

	Docket No. 6690-UR-122		Docket No. 6690-UR-123	
	¢/kWh	**% of Total**	**¢/kWh**	**% of Total**
Energy-Related	3.86	30.6%	4.32	35.5%
Demand-Related	4.81	38.2%	4.40	36.2%
Customer-Related	3.92	31.1%	3.44	28.3%
Total Expenses	12.59		12.15	

If, in fact, average rates are increasing primarily because of rising fuel costs rather than conservation, then the Company should take steps to educate consumers and clear up any misconceptions about what is in fact driving rate increases.

Even if rate increases are being driven by reduced sales, increasing the fixed charge is likely to create further confusion and frustration as consumers realize that their investments in efficiency improvements are not going to yield as much bill savings as they had anticipated. If customers are confused about the relationship between bill savings and rate increases from conservation, WPSC should not increase customers' frustration by increasing the fixed charge. Instead, the Company should enhance its efforts to 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: What does Ms. Ferguson mean when she says that the Company's proposed rate restructuring would create "sensible price signals"?

A: According to WPSC Response to 02-CUB/Inter-13 (PSC REF#: 206892), Ms. Ferguson apparently means that the proposed rate restructuring would yield energy charges that approach short-run marginal energy costs.[37]

Q: Do short-run marginal energy costs provide a reasonable price signal?

A: No. Short-run marginal energy costs do not reflect the full economic value of long-term investments in energy-efficiency or distributed-generation resources. 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.

As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, energy charges should reflect long-run marginal costs in order to provide appropriate and stable signals for investments in long-lived efficiency measures:

> By and large, the major influence exercised on consumer demand for utility services by any current rates of charge for these services is an influence based on the expectation that these rates indicate, at least in a general way, the rates that will remain in effect over a considerable period of time…. Once having become dependent on the services required for the operation of expensive complementary equipment, the consumer's responsiveness to temporary changes in rates of charge will probably be very limited. In short, the own price elasticity of demand for utility services can be expected to be much greater in the fairly long run than in any very short period of time.[38]

Q: What are the cross-subsidies that Ms. Ferguson alleges would be reduced with the Company's proposed rate restructuring?

---

[37] A copy of this response is attached as Ex.-CUB-Wallach-3.

[38] Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates,* Arlington, VA: Public Utilities Reports, 1988, p. 451.

A: Ms. Ferguson alleges that consumers without distributed generation are subsidizing those with distributed generation, because the latter customers pay a smaller share of the "fixed" costs recovered through the energy charge than the former customers.[39] Ms. Ferguson also argues that this cross-subsidization is especially inequitable for low-income customers, who lack the financial resources to invest in distributed generation.

Q: Do you agree that consumers with distributed generation are being subsidized through the current rate structure?

A: No. To the contrary, from a cost-causation perspective, it is appropriate for a low-usage customer to pay less for demand-related costs than a higher-usage customer. Just as class demands drive each class's responsibility for total system demand-related costs, individual customer demands drive each customer's responsibility for demand-related costs allocated to that class. When a lower-usage customer pays less for demand-related costs recovered through the energy charge than a higher-usage customer, that difference reflects the appropriate allocation of demand-related costs to individual customers within that class.

On the other hand, I agree with Ms. Ferguson that low-income customers have far fewer opportunities to benefit from distribution generation, either because of inadequate financial resources or because they live in rental or mobile housing. I encourage WPSC to explore initiatives for increasing low-income access to distributed generation, such as utility investment or financing of rooftop solar panels or community solar gardens.

[39] The Company's cross-subsidization concerns apparently do not extend to electric space heat customers who choose to reduce usage by switching to natural gas. In fact, the Company's web site emphasizes the economic benefits of such fuel switching with respect to the reductions in the energy portion of a customer's bill, where such reductions include reduced payment toward the "fixed" costs recovered through the energy charge.

Q: Does Ms. Ferguson offer any other justification for the Company's proposal to dramatically increase fixed charges?

A: Yes. Ms. Ferguson notes that electric cooperatives near WPSC have residential fixed charges that exceed the Company's proposed $25 charge. She then argues that:

> The comparison is useful because electric cooperatives set their own rates through a democratic process and their members choose to have a much higher fixed charge than the investor-owned utilities regulated by the PSCW.[40]

Q: Do cooperative members "choose to have a much higher fixed charge"?

A: While cooperatives may have higher fixed charges, it is not necessarily by choice. For example, according to the mission statement of Price Electric Cooperative:

> Because we operate in rural areas and have relatively low usage consumers, we cannot keep our rates as low as the investor owned utilities which serve the population centers in this area. Price Electric serves approximately 4.9 meters per mile of line compared to an average of 31 meters per mile for investor owned utilities. Their consumer base allows them to spread their expenses per mile over six times more meters, resulting in lower rates. We must continue to operate as efficiently as possible to keep our rates affordable for rural residents.[41]

Furthermore, given that a cooperative's rates are set outside of the PSC rate case process, no party has the benefit of an evidentiary record from which to analyze justifications for why rates are set at any given level, a particular rate design selected, or whether a cooperative's costs are comparable to those of a large investor-owned utility.

[40] Direct-WPSC-Ferguson-15, ll. 4-6.

[41] http://www.price-electric.com/about.htm

Q: How does the proposed residential fixed charge of $25 compare against municipal utilities' customer charges?

A: As indicated in Ex.-CUB-Wallach-4, residential customer charges for Wisconsin's municipal utilities range from $3.25 to $8 per month. Thus, the Company's proposed fixed charge is about three to eight times higher than municipal utilities' residential customer charges.

Q: What do you recommend with regard to the Company's proposal to restructure rates and increase residential and small C&I fixed charges?

A: The Commission should reject the Company's proposal to increase residential and small C&I fixed charges. The Company's proposal would unreasonably shift costs to the fixed charge that are more appropriately recovered through energy charges. Such a shift would distort price signals, frustrate investments in energy efficiency and distributed resources, and inequitably burden smaller customers.

Q: Would any increase to residential and small C&I fixed charges be appropriate?

A: Not in the instant proceeding. As I discussed in Section III, the results of the Commission staff audit cost of service studies indicate that it would not be appropriate to increase residential and small C&I rates in the 2015 test year. In fact, all four of those studies indicate that residential and small C&I rates should be lowered. In either case, it would be unfair to increase small customers' bills while other consumers enjoy stable or even lower bills.

Moreover, an increase in 2015 test year fixed charges would be particularly harmful coming on top of the substantial increase in the 2014 test year customer charges. As I discussed above, repeated changes to fixed charges will destabilize and dampen price signals for long-term investments in energy efficiency or distributed generation.

As I discuss below, it may be appropriate to increase fixed charges and implement other changes in rate design in future rate proceedings. However, such changes should be considered as part of a broader strategy for responding to long-term industry changes.

Q: What do you recommend with regard to the design of residential and small C&I rates?

A: As I noted in Section III, I will recommend specific revenue allocations and rate designs as part of my rebuttal testimony.

V. Transformation of the Electric Utility Industry

Q: Why is the Company concerned about restructuring its rates at this time?

A: According to Ms. Ferguson, even though distributed generation customers currently represent a very small portion of its total customer base, the number of net metering customers has been growing rapidly. With an expectation of continued growth in distributed generation, WPSC believes that it is appropriate to restructure rates at this time.[42]

In Docket No. 6690-UR-122, the Commission similarly found that the time is right to address the implications of a growth in distributed generation:

[42] Direct-WPSC-Ferguson-13, ll. 12-17.

> The Commission has every reason to believe that interest in customer-owned distributed generation will continue to increase as the cost of such generating systems become more cost competitive with retail electric service. As such, the focus should be on getting the right policies in place before this becomes a more significant cost issue.[43]

Q: Would it be reasonable to expect substantial growth in residential distributed generation in the Company's service territory?

A: Yes, if national trends are any indication of potential growth in the Company's service territory. According to a research report by Citigroup, distributed solar capacity in the U.S. increased by a factor of nine between 2007 and 2012, and is expected to increase by about ten-fold between 2012 and 2020.[44] According to a recent article in the *Energy Law Journal*, a new rooftop solar system was installed in the U.S. at an average rate of every four minutes in 2013.[45] In addition, the Interstate Renewable Energy Council reports that the pace of new residential solar installations (in terms of capacity added) increased 68% from 2012 to 2013.[46] These statistics indicate that we can expect continued rapid growth in residential distributed generation in the Company's service territory.[47]

Q: What factors are driving the rapid growth in residential rooftop solar installations?

---

[43] Final Decision, Docket No. 6690-UR-122, p. 53.

[44] Citi Research, *Rising Sun: Implications for U.S. Utilities*, August 8, 2013, Figure 9.

[45] Elisabeth Graffy and Steven Kihm, "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?", *Energy Law Journal*, Vol. 35, No. 1, 2014, p. 4.

[46] Larry Sherwood, *U.S. Solar Market Trends: 2013*, Interstate Renewable Energy Council, July, 2014, p. 7.

[47] I am not aware of any projection of such growth by WPSC. In response to CUB discovery, the Company stated that its current forecast of residential sales does not reflect any impact from distributed generation. See WPSC Response to 08-CUB/Inter-03 (PSC REF#: 213354).

A: A number of factors are driving the explosive growth in rooftop solar, including growing consumer awareness and acceptance of renewable technology, innovations in third-party financing of rooftop installations, government incentives and tax subsidies, and rapidly improving economics. In particular, solar equipment and balance-of-system (i.e., permitting, installation, and interconnection) costs have plummeted since 2008, and are expected to continue to fall through the rest of the decade.[48] At this rate of improvement, it may not be long before residential installations no longer require government incentives or tax subsidies to achieve cost-effectiveness:

> Most predict that by 2020, utilities will reach a tipping point where power from rooftop solar PV will become cheaper than power from the grid in most parts of the US.[49]

Q: What does this growing embrace of distributed generation imply for the electric utility industry?

A: Although it is difficult to predict how exactly this will play out, widespread adoption of distributed renewable resources could fundamentally transform the industry: from a centrally planned and operated grid designed for reliable delivery of power to energy consumers to a distributed network with power supplied by both conventional generation and energy "prosumers." Such a transformation would entail not just a change in the core transactional relationship between utilities and customers, but would also require a reformulation of the regulatory policies, planning approaches, investment

---

[48] Citigroup forecasts a 42% to 53% drop in the total cost of a residential installation by 2020. See *Rising Sun: Implications for U.S. Utilities*, p. 19.

[49] Ernst & Young LLP, *From Defense to Offense: Distributed Energy and the Challenge of Transformation in the Utilities Sector*, 2014, p. 1.

strategies, and cost-recovery mechanisms that are at the heart of the traditional utility model.

Q: How has WPSC responded to the potential transformation of the industry?

A: As discussed above, the Company's (and other Wisconsin utilities') initial response has been defensive: increasing customer charges and reducing energy charges in order to counteract a "disruptive" threat to earnings. The Company's narrow focus on financial risk is not surprising, since an influential Edison Electric Institute (EEI) report published in 2013 effectively framed the issue as a threat to financial viability:

> While the various disruptive challenges facing the electric utility industry may have different implications, they all create adverse impacts on revenues, as well as on investor returns, and require individual solutions as part of a comprehensive program to address these disruptive trends. Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality.[50]

With its narrow focus on financial risk, the EEI report characterizes rate restructuring as a "near-term, must-consider action by all policy setting industry stakeholders."[51]

Q: Is rate restructuring a viable strategy for maintaining financial health in the longer term?

A: Not on its own. Such narrowly tailored, defensive strategies are unlikely to position the Company to thrive over the long term. In fact, such strategies may ultimately prove counter-productive, since their success depends on frustrating customers' desire for distributed generation:

---

[50] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, Edison Electric Institute, January 2013, p. 1.

[51] *Id.*, p. 2.

> In the short run, these steps very well could insulate the utility from solar PV competition but at the same time create substantial medium- and long-term risks, including those of customer backlash, deferral of adaption, and stimulation of enhanced competition.[52]

Or, as Ernst & Young sees it:

> The threat DER [distributed energy resources] poses to incumbents is significant, and attempting to deny the situation with status quo forecasts or blocking the inevitable outcome by penalizing customers who adopt DER is futile.[53]

On the other hand, while inadequate in isolation, rate restructuring could prove to be a key component of a broader, more comprehensive strategy that is designed to accommodate expected long-term changes in the provision and delivery of electricity service. Such a long-term strategy would view distributed generation not as a competitive threat, but as a potentially valuable supply resource that could lower costs, mitigate fuel and environmental risks, and enhance distribution-system reliability.[54]

Q: What steps can the Commission take to position WPSC to remain viable in the long term?

A: The Commission should direct the Company to work with interested parties to develop for implementation in 2016 a package of regulatory policies, planning procedures, investment strategies, and rate designs that accommodate the changes overtaking the industry. This process should have a broad scope that allows for a comprehensive assessment of current policies and practices and a

[52] Graffy and Kihm, p. 31.

[53] Ernst & Young, p. 1.

[54] For example, see Anne Hampson and Jessica Rackley, *From Threat to Asset – How CHP Can Benefit Utilities*, ICF International, Inc., 2014.

thorough examination of a wide range of business strategies. In particular, this process should:

- Forecast the potential for distributed generation in the Company's service territory over the planning horizon.
- Assess the impacts of widespread installation of distributed resources on the Company's current load forecasts and resource plans, including consideration of whether existing assets may no longer be economically used and useful.
- Evaluate opportunities for distributed resources to substitute for reliability upgrades to local distribution networks.
- Consider investment strategies for reducing market barriers and widening access to distributed generation, including utility ratebasing or financing of rooftop and community solar installations.[55]
- Evaluate strategies for pricing distributed generation at a rate that reflects long-run value, including the market energy costs, generation capital and fixed O&M, MISO transmission charges, distribution capital and fixed O&M, Renewable Portfolio Standard costs, carbon costs, and risks avoided by distributed generation.[56]
- Evaluate alternative rate designs, including increased fixed charges coupled with inclining block rates for energy.[57]

---

[55] As with energy efficiency resources, one of the most effective ways to reduce short-term impacts on non-participants is to broaden participation.

[56] For a survey of Value of Solar pricing approaches, see Michigan Public Service Commission, *Solar Working Group – Staff Report*, June 30, 2014.

[57] An inclining block energy rate would offer two benefits. First, the lower-priced initial energy block would mitigate the harm to lower-usage customers from increases in the fixed charge. Second, pricing for the marginal energy block would provide appropriate price signals for long-lived investments in energy efficiency.

Q: Does this complete your direct testimony?

A: Yes.