BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, to Conduct a Biennial Review of Costs and Rates – Test Year 2015	))))	Docket No. 05-UR-107

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

August 28, 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 May 30, 2014, Wisconsin Electric Power Company (WEPCO or "the Company") filed an application to increase electric rates for the 2015 and 2016 test years. The Company subsequently filed additional supporting testimony on June 27, 2014. My testimony addresses the following aspects of the Company's filing:

- The methods used by WEPCO in its electric cost of service study (COSS) to allocate the proposed 2015 and 2016 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 Eric A. Rogers.
- The Company's long-term plan to restructure residential and small C&I rates, including its proposal to increase the residential and small C&I

facilities charges in 2015, as described in the pre-filed direct testimony of Company witnesses Mr. Rogers and Michael T. O'Sheasy.

- The Company's proposal to extend the terms of current contracts under the Real-Time Market Pricing (RTMP) rider by 36 months and to continue to use the original contract energy and demand baselines during these extended terms, as described in the pre-filed direct testimony of Company witness Mr. Rogers.

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 1.8% in order to recover an expected revenue deficiency of $52.3 million in the 2015 test year. The Company is further requesting that electric rates be increased by an additional 0.9% in the 2016 test year to reflect the expiration of $26.6 million of deferred fuel cost and tax credits at the end of the 2015 test year. Based on the results of a single cost of service study, WEPCO proposes to increase residential and small C&I rates on average by 3.4% in test-year 2015 and by another 0.8% in test-year 2016.

The Company's cost of service study overstates the portion of the test-year 2015 and 2016 revenue deficiencies 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 reasonable.

As the Commission found in Docket No. 05-UR-106, it is appropriate to allocate the 2015 and 2016 test year revenue deficiencies based on the range of results from multiple cost of service studies. However, in this docket, WEPCO has failed to provide a range of results for the Commission's consideration. It is my understanding that Commission staff will be performing a number of studies as part of its direct filing. In order to avoid duplication in the record, I intend to offer my proposed recommendation for allocation of the 2015 and 2016 test year revenue deficiencies in rebuttal testimony after I have had the opportunity to review Commission staff's cost of service studies.

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 plan to eventually shift all allegedly "fixed" costs from the energy charge to the facilities charge or some other type of "fixed" charge. Redesigning residential and small C&I rates in the fashion proposed by WEPCO would inappropriately shift load-related costs to the facilities 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.

The Company also lacks a reasonable basis for its transitional proposals for the 2015 and 2016 test years to increase residential and small C&I facilities charges for single-phase service by about 75% and to eliminate the difference between single-phase and three-phase facilities charges. Consequently, the Commission should reject the Company's proposal and instead find that it is reasonable to maintain facilities charges at current levels. If any increases to residential and small C&I revenues are allowed by the Commission, such increases should be recovered solely through the energy charge.

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 facilities charges at current levels.

Q: Please summarize your findings and recommendations regarding the Company's proposal to extend the terms of current RTMP contracts.

A: The Company's proposal to continue the energy and demand baselines from the original contract term during the three-year extension is not reasonable. After four years under the existing contract, it would not be appropriate to continue to price load in excess of original baselines as if it were new or incremental to the baseline. Consequently, the Commission should deny the Company's request to use original baselines if the terms of existing contracts are extended. Instead, baselines should be updated in accordance with the provisions of the RTMP rider for setting baselines for new contracts.

II. Cost Allocation

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

A: For the 2015 test year, WEPCO is requesting that electric rates be increased on average by 1.8% in order to recover an expected revenue deficiency of $52.3 million. Of the total $52.3 million requested revenue increase, WEPCO proposes to allocate $49.6 million to residential and small C&I customers.[1] This amount represents a 3.4% increase over residential and small C&I revenues under current rates.

For the 2016 test year, the Company requests that electric rates be increased by an additional 0.9% over proposed rates for the 2015 test year in

[1] Ex.-WEPCO/WG-Rogers-15, Schedule 1.

order to recover an expected revenue deficiency of $78.9 million.[2] The revenue deficiency for the 2016 test year reflects the expiration in 2015 of the fuel cost deferral, CSAPR amortization, and biomass tax grant credits. The Company proposes to increase residential and small C&I rates by an additional 0.8%, or $11.7 million, in order to reflect the portion of the $26.6 million of expiring credits allocated to those classes.

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

A: According to Mr. Rogers, the Company relied on a single cost of service study ("WEPCO COSS") to develop its proposal for allocating the 2015 and 2016 test year revenue deficiencies to the customer classes.[3] For test-year 2015, this cost of service study shows a revenue deficiency of about $77.9 million, or about 5.3% of revenues under current rates, for residential and small C&I customers.[4] For test-year 2016, the WEPCO COSS shows a revenue deficiency of about $89.7 million, or about 6.2% of revenues under current rates, for residential and small C&I customers.

Q: Did the Company develop only one cost of service study in its previous rate case?

A: No. In Docket No. 05-UR-106, WEPCO conducted six cost of service studies that differed with respect to the methods used to classify and allocate production

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[2] *Id.*

[3] The Company conducted one other cost of service study, which differs from the WEPCO COSS solely with respect to the allocator used to allocate energy-related costs. However, Mr. Rogers does not describe the results of this "alternate case" cost of service study or in fact make mention of this alternative in his direct testimony other than to note its existence.

[4] Ex.-WEPCO/WG-Rogers-12r, Schedule 18A.

plant costs. These studies varied the proportion of demand-related to energy-related production plant costs, ranging from 100% demand-related and 0% energy-related to 50%/50% demand/energy.[5] In addition, the studies allocated demand-related production plant costs on the basis of each customer class's contribution to either the average of the twelve monthly system coincident peaks ("12CP") or the average of the four summer coincident peaks ("4CP").

In his testimony in Docket No. 05-UR-106, Mr. Rogers explained why the Company chose to provide more than one cost-of-service study in that proceeding:

> We are providing multiple versions of the cost-of-service study, with each version varying the method used to allocate production plant to customer classes. The PSCW staff briefing memorandum in Docket 05-EI-137 dated August 17, 2006 describes various methods for allocating costs to customer classes, and we agree that no one method is considered the "correct COSS", although I do believe there is a range of acceptable methods. In other words, not every cost of service study necessarily provides a valid result. The various cost-of-service studies we have performed provide points on a range of reasonable results. Each point on the range reflects differences in the amount of costs allocated to one class of customers versus another class of customers. We used one of these cost-of-service studies as the starting point, or base case, for the rate design.[6]

In contrast, in this docket the Company used only one cost of service study method to classify and allocate production plant costs. As a result, the Company denied the Commission the opportunity to consider a "reasonable range of

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

[6] Direct-WEPCO/WG-Rogers-10, ll. 6-14, Docket No. 05-UR-106 (PSC REF#: 164646).

results" in order to rule on the appropriate allocation of the overall revenue deficiency to customer classes.

The Company's abrupt shift to a single cost of service study methodology also appears contrary to Mr. Roger's testimony from Docket No. 05-UR-106 regarding the need to avoid making swift and significant changes to cost of service study methods. In response to a question regarding how Mr. Rogers' assesses whether a particular cost of service study methodology is valid for inclusion in a group of studies with a range of reasonable results, Mr. Rogers noted:

> Finally, I don't believe that a dramatic change to a method should be made too quickly. The cost of service study provides a measurement of changes in class rate design, and if dramatic changes to the study are employed too quickly, then assessment of the proper design will be more difficult. As in other matters before this Commission, gradualism is important in making changes.[7]

Q: Why did WEPCO use only one approach for classifying and allocating production plant costs in the instant proceeding?

A: Mr. Rogers does not explain why the Company chose to not conduct multiple cost of service studies in this proceeding. However, it is my understanding that the Company agreed to use only one approach for classifying and allocating production plant costs as part of a settlement agreement with the Wisconsin Industrial Energy Group (WIEG).

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

A: No. The allocation of costs to customer classes in the WEPCO COSS does not reasonably reflect each class's responsibility for such costs. In particular, the

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[7] *Id*. at Direct-WEPCO/WG-Rogers-10, ll. 18-23 and Direct-WEPCO/WG Rogers-11, ll. 1-2.

WEPCO 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 WEPCO COSS classify and allocate production plant costs?

A: The WEPCO COSS classifies 75% of production plant costs as demand-related and the remaining 25% as energy-related. Moreover, the WEPCO COSS allocates demand-related production plant costs using the 4CP allocator.

Q: Is there a reasonable basis for the Company's assumption of a 75%/25% demand/energy split in production plant costs?

A: No. As noted above, the assumed split is simply what WEPCO agreed to as part of a settlement agreement with WIEG. The Company has not offered any evidence to show that the assumed split is reasonable or appropriate.

Instead, Mr. Rogers attempts to justify the split by noting that the Company assumed a 75%/25% demand/energy split in Docket No. 05-UR-101 and that the Michigan Public Service Commission has used the same split. What Mr. Rogers fails to note is that the Company abandoned the 75%/25% split in the subsequent rate case in Docket No. 05-UR-102. Moreover, he fails to offer any argument for the relevance of the Michigan Public Service Commission's classification procedures to this case.[8]

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[8] Nor does Mr. Rogers explain why the Company believes it should adopt the Michigan Public Service Commission's procedures for classifying production plant costs, but not its procedures for classifying distribution plant costs. As discussed below in Section III, the Michigan Public Service Commission requires that meter and service costs be classified as customer-related and that all other distribution plant costs be classified as demand-related. In contrast, WEPCO proposes in this case to classify a portion of the costs for distribution plant other than meters and services as customer-related.

Q: How has the Company classified production plant costs since Docket No. 05-UR-101?

A: Starting in Docket No. 05-UR-102 and through the previous rate case in Docket No. 05-UR-106, WEPCO has used the "Equivalent Peaker" method to classify production plant costs as either demand-related or energy-related.[9]

The Equivalent Peaker method classifies fixed costs (i.e., capital and fixed O&M costs) for a peaking unit as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. The Equivalent Peaker method likewise classifies fixed costs for a baseload or intermediate unit *in excess of peaking fixed costs* (so-called "capitalized energy" costs) as energy-related, since these incremental fixed costs are incurred to minimize the total cost of meeting an increase in energy requirements.

Q: Why did the Company adopt the Equivalent Peaker approach in Docket No. 05-UR-102?

A: After evaluating different methods for classifying production plant costs, WEPCO adopted the Equivalent Peaker method because it best reflects investment decision-making under typical generation expansion planning practices. According to Mr. Rogers's testimony in that proceeding:

> We used the equivalent peaker method in our cost-of-service model. This is the method that best fits the theory that base load and intermediate load plants are built to provide less expensive energy, as well as providing capacity. We believe this is the most appropriate theory to use for allocating the production plant costs.[10]

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

[10] *Direct Testimony of Eric A. Rogers*, Docket No. 05-UR-102, July 2005, p. 16, ll. 11-14 (PSC REF#: 36950).

Q: Has the Company explicitly stated in the instant proceeding whether it still believes that the Equivalent Peaker method is "the most appropriate theory to use for allocating production plant costs"?

A: No. However, in response to CUB interrogatories, the Company acknowledges that it conducted an Equivalent Peaker analysis for the 2015 test year. In contrast with the assumed 75%/25 demand/energy split adopted for the WEPCO COSS, the Company's Equivalent Peaker analysis for the 2015 test year classifies 42% of production plant costs as demand-related and 58% as energy-related.[11]

Q: Does the Company's assumed 75%/25% demand/energy classification of production plant costs reasonably allocate such costs to residential and small C&I customers?

A: No. As indicated above, the Company's assumed 75%/25% split overstates the portion of production plant costs reasonably classified as demand-related under the Equivalent Peaker method. Misclassifying energy-related costs as demand-related results in an over-allocation of such misclassified costs to the 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: I have not, since it is my understanding that Commission staff, as part of its direct filing, will be deriving an alternative classification based on the

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[11] "Cost of Service and Rate Design for TY2015", p. 3. Provided as attachment to WEPCO Response to 2-CUB/Inter-1 (PSC REF#:213306).

[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.

Equivalent Peaker method for the purposes of allocating audit revenue requirements.

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

A: The Company proposes to use a 4CP allocator to allocate demand-related production plant costs. The Company first argued for relying on a 4CP allocator in Docket No. 05-UR-106; prior to that, WEPCO relied on the 12CP allocator. As noted by Mr. Rogers in Docket No. 05-UR-106, the change from a 12CP to a 4CP allocator shifts costs from the large to the small customer class.[13]

Q: Why did the Company propose to switch from a 12CP to a 4CP allocator in Docket No. 05-UR-106?

A: According to Mr. Rogers's testimony in that proceeding, the pattern of monthly peaks had changed over time, from one that was relatively flat across months to one where "the difference between our summer peaks and winter peaks have become more pronounced."[14] Based on this changing pattern, Mr. Rogers concluded that:

> Although what we've argued in the past, (that we must plan for capacity in all twelve months of the year), is still true, our summer peaks are clearly the primary determinant of our capacity planning.[15]

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[13] Direct-WEPCO/WG-Rogers-38, ll. 9-11, Docket No. 05-UR-106. As indicated by data provided in WEPCO Response to 2-CUB/RFP-7 (PSC REF#:213681), the same holds true in this proceeding: the WEPCO COSS allocates a greater portion of demand-related production plant costs to the residential and small C&I classes using the 4CP allocator (49.0%) than would be the case using the 12CP allocator (46.5%).

[14] Direct-WEPCO/WG-Rogers-13, ll. 5-6, Docket No. 05-UR-106.

[15] Direct-WEPCO/WG-Rogers-13, ll. 6-8, Docket No. 05-UR-106.

Q: Did WEPCO reasonably justify its proposal to switch from a 12CP to a 4CP allocator in Docket No. 05-UR-106?

A: No. As I discussed in my direct testimony in that proceeding, while WEPCO had provided evidence that the gap between summer and winter peaks had grown over time, the Company had not shown that the need for new reserve capacity is more strongly driven by summer peaks today than it had been in the past. In other words, even when the gap between summer and winter peaks was less in the past, it is likely that summer peaks were the "primary determinant" of the need for new reserve capacity. What the Company failed to show was that the gap was large enough that summer peaks had become not just the primary, but the sole determinant of the Company's capacity planning.[16] As such, WEPCO had not reasonably justified its proposal to allocate demand-related costs as if capacity planning were driven solely by summer peaks.

Q: What do you recommend with respect to the classification and allocation of production plant costs?

A: The Commission should reject the Company's proposals to classify production plant costs as 75% demand-related and 25% energy-related. Instead, WEPCO should continue to classify such costs using the Equivalent Peaker classification method, as it has done in previous rate cases.

The Commission should also reject the Company's proposal to allocate demand-related production plant costs using the 4CP allocator. Such costs should be allocated to customer classes using the 12CP allocator, consistent with cost-causation.

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[16] In fact, as noted above, the Company still believed in Docket No. 05-UR-106 that it "must plan for capacity in all twelve months of the year."

B. Allocation of Distribution Plant Costs

Q: Does the WEPCO COSS reasonably allocate distribution plant costs to the residential and small C&I classes?

A: No. The WEPCO COSS classifies certain distribution plant costs as either customer-related or demand-related based on a minimum distribution system analysis. The minimum distribution system method is fundamentally flawed and tends to misclassify demand-related costs as customer-related. As a result, the WEPCO COSS overstates the appropriate allocation of distribution plant costs to the residential and small C&I classes.

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 distribution plant costs does the Company classify according to the minimum distribution system method in the WEPCO COSS?

A: The Company uses the minimum distribution system method to classify all distribution-feeder costs as either demand-related or customer-related. Specifically, the WEPCO COSS uses the minimum-intercept method to classify the costs for overhead poles, towers, and fixtures (FERC Account 364). For other overhead and underground distribution-feeder costs (FERC Accounts 365 through 367), the WEPCO COSS uses the minimum-size method.

All other distribution plant costs are either directly assigned or classified as 100% demand- or customer-related. The Company classifies all distribution substation costs (FERC Accounts 360 and 361) as demand-related. Services (FERC Account 369) are considered to be customer-related. Costs for secondary transformers (FERC Account 368) and meters (FERC Account 370) are directly assigned.[17]

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

[17] Although directly assigned for cost-allocation purposes, transformer costs are classified using the minimum-intercept method for rate-design purposes.

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-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.[18]

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.

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

Figure 1a

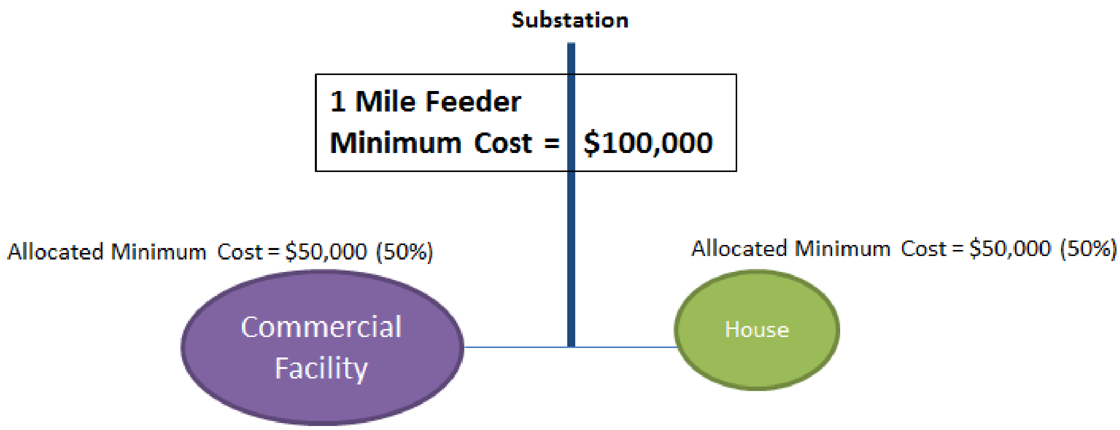
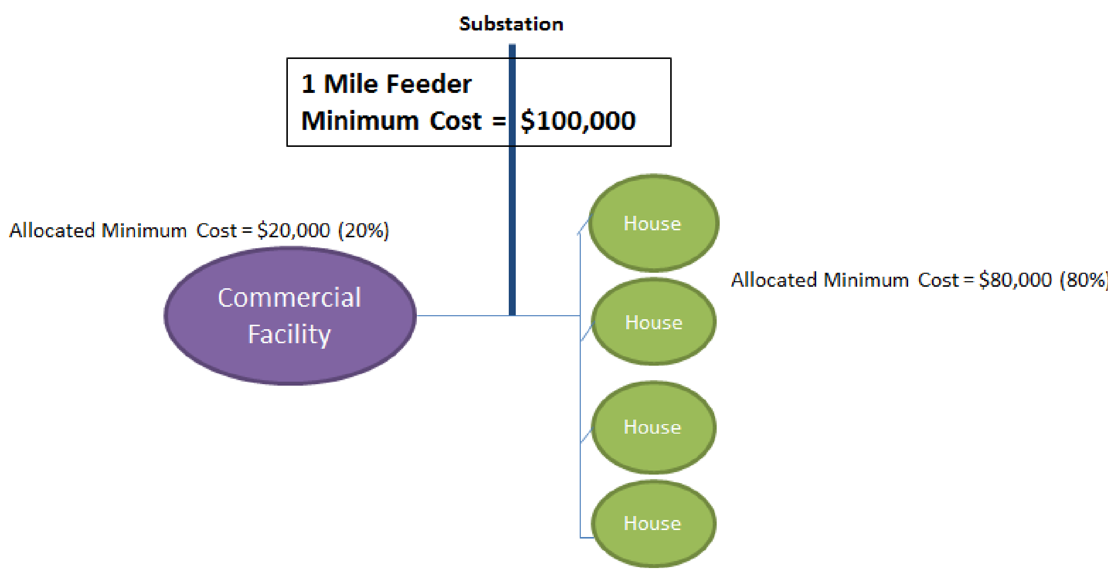


Figure 1b



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 **<u>not</u>** 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 when these non-customer-related minimum costs are arbitrarily classified as customer-related rather than demand-related under the minimum distribution system approach. 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.[19] 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

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

customers.[20] 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 costs as demand-related costs, even though these excess costs were not incurred to serve residential load.[21]

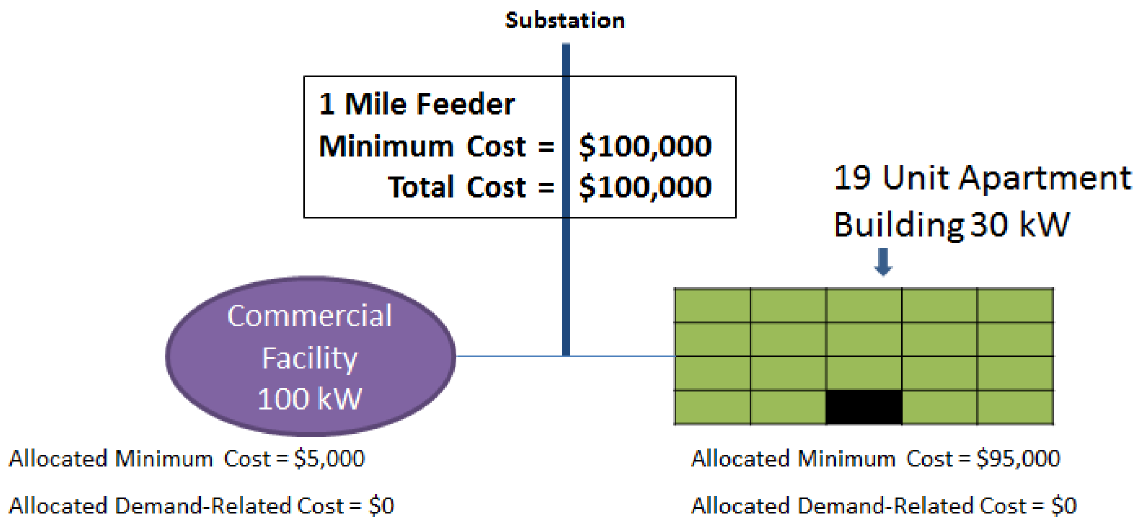
Figures 2a and 2b illustrate this problem of over-allocation of demand-related costs when using the minimum-size method. As in Figures 1a and 1b, Figures 2a and 2b assume a hypothetical distribution system consisting of a single one-mile feeder. In the example shown in Figure 2a, there are 20 customers 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.[22]

[20] 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.

[21] According to Mr. Rogers, the Company partially corrects for this problem by assuming that only 50% of the cost of the minimum-sized conductor is customer-related. (Direct-WEPCO-Rogers-20, ll. 14-17.)

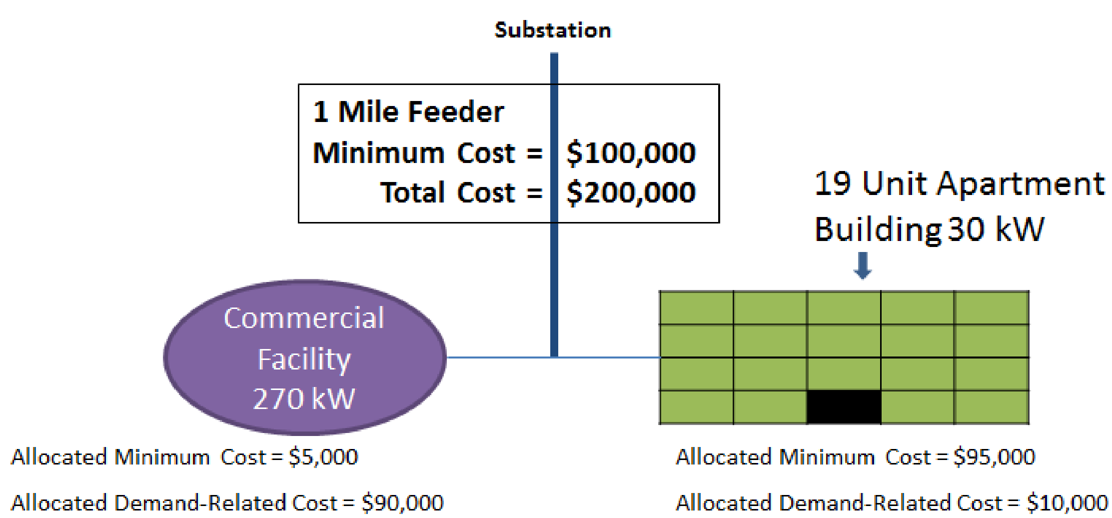
[22] As discussed above with regard to Figures 1a and 1b, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

Figure 2a



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.[23]

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-feeder costs?

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[23] 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.

A: Yes. A reasonable and reasonably straightforward approach, and one that has been used in other jurisdictions, is to classify as demand-related all distribution plant costs, other than the costs for services and meters or costs that are directly assigned.[24]

In fact, the Michigan Public Service Commission requires that the Company classify distribution plant costs in just this fashion.[25] Specifically, the Michigan PSC requires that costs for services and meters be classified as 100% customer-related and that costs for all other distribution plant be classified as 100% demand-related.

III. Rate Design

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

A: According to Mr. Rogers, WEPCO intends to radically restructure residential and small C&I rates by eventually shifting recovery of allegedly "fixed" costs from the energy charge to the facilities charge or some other type of "fixed" charge. As an initial step, WEPCO proposes to recover through the facilities charge all costs classified as customer-related in the WEPCO COSS. To do so, WEPCO proposes to dramatically increase the facilities charge for residential and small C&I customers taking single-phase service from $0.30/day (about $9.13/month) to $0.526/day (about $16/month), or by about 75%.[26] In addition,

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[24] 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.

[25] WEPCO Response to 4-CUB/Inter-1 (PSC REF#:214266).

[26] Ex.-WEPCO/WG-Rogers-14.

the Company proposes to set the facilities charge for three-phase service equal to that for single-phase service. To accommodate these steep increases to monthly facilities charges, WEPCO proposes to reduce the base energy charge for Rg-1 and Cg-1 customers by about 3.3%.

Q: By what amount would WEPCO have to increase the residential and small C&I facilities charge in order to recover all of the costs the Company considers to be "fixed"?

A: Based on data provided in WEPCO Revised Response to 2-CUB/RFP-7 (PSC REF#: 213681), I estimate that the facilities charge would have to increase to about $89/month, or by almost ten times the current level for single-phase service, in order to recover all costs allocated to the residential and small C&I classes under the WEPCO COSS that the Company considers to be "fixed."

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

A: If the facilities charge for the Rg-1 rate class were increased to $89/month, the base energy charge would have to be reduced dramatically from about 13.9¢/kWh to about 2.1¢/kWh.[27]

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

A: Not at this time. However, according to Mr. Rogers, the Company's proposal for the 2015 and 2016 test year facilities charge is just a first step in a plan to

[27] This calculation is based on the revenue allocation to the Rg-1 rate class reflected in Ex.-WEPCO/WG-Rogers-15.

eventually shift recovery of all allegedly "fixed" costs out of the energy charge and into some form of "fixed" charge:

> We view these proposals as an initial step in moving rate design toward ultimately recovering all or most fixed costs through fixed charges and all or most variable costs through variable or volumetric charges. Consistent with the principle of gradualism, we are proposing limited steps in that direction in this proceeding. We expect to propose further steps in subsequent rate cases.[28]

Q: What are the "fixed" costs that WEPCO proposes to eventually recover through a fixed charge on residential and small C&I customers?

A: According to WEPCO Response to 5-CUB/Inter-1(a) (PSC REF#:214267), "fixed" costs are all costs other than those classified as energy-related in the WEPCO COSS. This includes not only all costs that are classified as customer-related in the WEPCO COSS, but also all costs (whether generation, transmission, or distribution) classified as demand-related.

Based on data provided in WEPCO Revised Response to 2-CUB/RFP-7, I estimate that the "fixed" demand-related costs constitute about 81% of the total "fixed" cost for residential and small C&I customers.

Q: Would it be reasonable to recover all costs classified in the WEPCO COSS as customer-related through residential and small C&I facilities charges, as the Company proposes?

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[28] Direct-WEPCO/WG-Rogers-3, line 21 to Direct-WEPCO/WG-Rogers-4, line 2. As I discussed in my direct testimony in Docket No. 6690-UR-123, the Commission should not consider any proposal to recover most or all of WEPCO's allegedly "fixed" costs through a "fixed" charge in isolation. The electric industry is undergoing rapid changes and a comprehensive strategy should be adopted for adapting to the evolving industry. See Docket No. 6690-UR-123, Direct-CUB-Wallach-5-6 and 36-41 (PSC REF#:213733).

A: No. As discussed above, the WEPCO COSS misclassifies demand-related distribution costs as customer-related by relying on the minimum distribution system method. As a result, the WEPCO 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, I estimate that residential and small C&I facilities charges would be about 65% of what the Company is proposing, if such charges were set to recover all costs reasonably classified as customer-related. Specifically, based on data provided in WEPCO Revised Response to 2-CUB/RFP-7, I estimate that customer-related costs allocated to the residential and small C&I classes under the WEPCO COSS would amount to about $10.50 per month if all distribution plant costs (other than for services and meters) were classified as demand-related.

In addition, it would not be appropriate to recover through facilities charges the full $10.50/month amount for customer-related costs. 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 facilities charge. For example, a number of customer-classified distribution costs – such as services or uncollectible accounts and collection expense – are likely to vary with the size of the customer (in revenues, sales, or demand). If such costs were recovered through a facilities charge, then the smallest residential customers (with the least-expensive distribution equipment) would be required to pay the average of customer costs attributable to all sizes of residential customers. In other words, if all customers were to pay the same facilities charge regardless of size, then small customers would subsidize larger customers' distribution costs.

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

A: No. Such costs may appear "fixed" when considered in the short-term context of utility cost recovery, since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load or sales in that year. 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 facilities 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 plan to restructure rates would misleadingly and inefficiently signal to consumers that there is no economic gain or loss associated with changes in peak demand.[29]

Even the Company's outside rate-design expert agrees that recovery of demand-related costs through the energy charge, as opposed to a "fixed" charge, is reasonable. According to Company witness Mr. O'Sheasy:

> However demand related costs do vary with usage albeit only with usage during the brief peak demand period. Therefore demand costs are somewhat of a hybrid between energy-related costs which vary with kWh volume and customer related cost which basically remains insensitive to usage. By placing demand related costs in the energy charge, a change in usage is somewhat linked with a change in demand related cost and is therefore reasonable.[30]

[29] In fact, the Company's plan could further and needlessly increase facilities charges, in order to recover uneconomic plant investment required to meet demand growth resulting from misleading price signals.

[30] Direct-WEPCO/WG-O'Sheasy-9, ll. 15-20.

Q: Why is WEPCO proposing to radically redesign residential and small C&I rates?

A: Mr. O'Sheasy offers two arguments for shifting recovery of allegedly "fixed" costs from the energy charge to some type of fixed charge:

> If some portion of fixed cost, such as customer cost, is recovered via the volumetric energy charge, then when actual sales fall short of forecast, fixed costs tend to be under-recovered. For periods of sustained economic underperformance, the shortfall can accelerate the need for a rate case and degrade the utility's earnings between rate cases, adversely affecting the utility's realized rate of return and increasing its financing cost. The opposite impact upon earnings can occur if energy sales are greater than necessary, but this is less likely with the prevailing economic environment. Also, including customer-related or other fixed costs in a utility's energy charge will create a price distortion from incremental cost thereby making it difficult for users to make wise economic decisions.[31]

I address each of these arguments in turn.

Q: How can a sales shortfall adversely affect earnings?

A: In general, rates in Wisconsin 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 actual sales in the test year are lower than forecast for that test year, 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: Would a sales shortfall have a long-term impact on earnings?

A: No. If the sales shortfall is due to a random event, such as a cooler-than-expected summer, then the adverse impact should be limited to the current test year. If the sales shortfall reflects a permanent reduction in customer usage, then presumably the earnings impact would be limited to the time until the next rate

[31] Direct-WEPCO/WG-O'Sheasy-6, ll. 9-18.

case. At that point, rates for the upcoming test year can be reset based on an updated forecast that reflects any such permanent reduction.

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

A: An increase in the facilities 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.[32]

Q: Have the Company's earnings or financing costs been adversely affected by lower-than-forecast sales in the past?

A: Not according to Mr. O'Sheasy. Mr. O'Sheasy merely contends that sales-related earnings shortfalls or higher financing costs are a "logical possibility for any utility," not that the Company has actually experienced such adverse impacts in the past or that WEPCO is likely to experience such adverse impacts in the future.[33]

Q: What does Mr. O'Sheasy mean when he says that recovering "fixed" costs through the energy charge creates a "price distortion from incremental cost"?

A: Mr. O'Sheasy apparently means that recovering "fixed costs" through the energy charge creates an economically inefficient price signal, since:

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[32] The Company could eliminate sales-related earnings risk by shifting all demand-related costs from the energy charge to the facilities charge. As I discuss above, shifting all demand-related costs would increase the facilities charge to $89/month and reduce the energy charge to about 2.1¢/kWh for Rg-1 customers.

[33] WEPCO Response to 2-CUB/Inter-16 (PSC REF#:213299).

> … the price customers pay per unit of energy used (or can avoid paying by not using that unit) exceeds the variable cost of producing the energy since the price includes both the cost which varies with usage plus some amount of fixed cost which does not change with usage. Pricing the volumetric charge closer to unit variable cost is more likely to encourage efficient use and possible growth by customers than volumetric pricing which diverges from unit variable cost. That way when customers are deciding whether to use incremental units of energy, they will be comparing the value to them of incremental usage against actual cost of supplying the incremental energy.[34]

Q: Do you agree that variable cost reasonably represents the value of changes in usage?

A: No. Variable costs do not reflect the full economic value of long-term changes in electricity usage. The economic value of a reduction in customer load is measured not just by short-run variable 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

[34] Direct-WEPCO/WG-O'Sheasy-3, ll. 15-23.

> expected to be much greater in the fairly long run than in any very short period of time.[35]

Q: Does Mr. O'Sheasy offer any other justification for the Company's proposal to dramatically increase facilities charges?

A: Yes. Mr. O'Sheasy notes that most electric cooperatives in Wisconsin have residential fixed charges that exceed the Company's proposed $16 charge. As justification for his comparison with electric cooperatives' fixed charges, Mr. O'Sheasy relies on testimony in Docket No. 6690-UR-123 by Wisconsin Public Service Corporation witness Ronda L. Ferguson, who 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.[36]

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

A: As I noted in my direct testimony in Docket No. 6690-UR-123, 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.[37]

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

[36] Direct-WEPCO-Ferguson-15, ll. 4-6, Docket No. 6690-UR-123 (PSC REF#:204526).

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

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.

Q: How does the proposed facilities charge of $16 compare against municipal utilities' customer charges?

A: As indicated in Ex.-CUB-Wallach-2, residential customer charges for Wisconsin's municipal utilities range from $3.25 to $8 per month. Thus, the Company's proposed facilities charge is about two to five times higher than municipal utilities' residential customer charges.

Q: What do you conclude with regard to the Company's plan to eventually recover all "fixed" costs through the residential and small C&I facilities charges?

A: The Company's plan is ill-conceived and should be abandoned. Redesigning residential and small C&I rates in the fashion proposed by WEPCO would inappropriately shift load-related costs to the facilities 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.

Q: What do you recommend with regard to the Company's interim proposal to increase 2015 and 2016 test year facilities charges?

A: The Commission should reject the Company's proposal to increase residential and small C&I facilities charges to $16/month. The Company's proposal would shift costs to the facilities charge that are more appropriately recovered through energy charges.

Instead, residential and small C&I facilities charges should be maintained at current levels. If any increases to residential and small C&I revenues are allowed by the Commission, such increases should be recovered solely through the energy charge.

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.

IV. Real-Time Market Pricing Rider

Q: What does the Company propose for the Real-Time Market Pricing rider?

A: According to Mr. Rogers, the Company proposes to revise the RTMP rider to allow for a three-year extension of existing contracts. As a result, the maximum term for existing RTMP contracts would be increased from four to seven years.

In addition, WEPCO proposes to continue the energy and demand baselines from the original contract term during the three-year extension.

Q: What is the Company's rationale for not updating energy and demand baselines for the three-year extension of the original contract term?

A: Mr. Rogers does not explain why the Company is proposing that baselines not be updated. However, it is my understanding that the Company agreed to a continuation of original baselines as part of a settlement agreement with WIEG.

Q: Is the Company's proposal to maintain existing baselines reasonable?

A: No. Under the Company's proposal, RTMP customers would continue to pay discounted prices during the three-year term extension for load that was added at the outset of the original contract, four years before the start of the extension. It would not be reasonable to price such load as if it were new or incremental to the baseline after four years.

Q: What do you recommend with regard to the proposed RTMP extension?

A: The Commission should deny the Company's request to use original baselines if the terms of existing contracts are extended beyond the original four-year contract. Instead, baselines should be updated in accordance with the provisions of the RTMP rider for setting baselines for new contracts.[38]

Q: Does this complete your direct testimony?

A: Yes.

[38] I understand that Commission staff may provide an analysis of the Company's RTMP rate in direct testimony. If so, I may supplement this recommendation in rebuttal testimony based on information provided in that analysis.