BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates	))))	Docket No. 4220-UR-121

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

October 1, 2015

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 seventy 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, 4220-UR-119, 6690-UR-123, 05-UR-107, and 3270-UR-120. 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 29, 2015, Northern States Power Company of Wisconsin (NSPW or "the Company") filed an application to increase electric and gas rates for the 2016 test year. This filing included supporting testimony by Gerald W. Marx regarding the Company's electric cost of service studies (COSS) and by Deborah E. Erwin regarding the Company's proposal to increase the customer charge for residential and small commercial and industrial (C&I) customers. In addition, on September 8, 2015, Commission staff provided CUB (and other parties) the results of five cost of service studies based on the Commission staff audit forecast of 2016 test year electric revenue requirements.[1]

My testimony:

[1] Commission staff provided a corrected version of one of the studies on September 25, 2015.

- Examines the different classification and allocation methods used in the five audit cost of service studies and assesses the extent to which such methods are consistent with cost-causation principles.
- Describes my proposal for allocating to customer classes the Commission staff audit forecast of the 2016 test year electric revenue deficiency.
- Addresses the Company's proposed rate design for residential and small C&I customers, including its proposal to increase customer charges for these customer classes.

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

A: The Commission staff audit finds a revenue deficiency for the 2016 test year of about $10.4 million, or 1.48% of 2016 test year electric revenues under current rates.

At the request of Commission staff, NSPW conducted five cost of service studies based on the Commission staff audit forecast of 2016 test year revenue requirements. These five studies differ with respect to the methods used to classify and allocate production capacity and distribution plant costs. Of the five studies, the Method 5 COSS classifies and allocates production capacity and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs.

For the purposes of allocating the overall revenue deficiency to customer classes and setting rates for the 2016 test year, it would be appropriate to consider the results of all five of the audit cost of service studies. Based on the range of results from these five studies, I recommend that revenues for the residential class be increased by no more than 0.75% and that there be no increase from current revenues for the small C&I class. I will include in my rebuttal testimony my proposal for allocating 2016 test year revenues to each of the residential and small C&I rate classes.

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 dramatically increase customer charges for residential and small C&I customers. The increases proposed by NSPW would inappropriately shift load-related costs to the customer charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and exacerbate the subsidization of larger residential customers' costs by these low-usage customers.

Moreover, I find that the current customer charge reasonably reflects the incremental cost to connect customers. Consequently, the Commission should reject the Company's proposal to increase the customer charge from $8 per month to $18 per month for residential and 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 proposal for allocating the 2016 test year revenue deficiency and my recommendation to maintain customer charges at current levels.

II. Cost Allocation

Q: What does the Commission staff audit find with regard to the expected revenue deficiency for the 2016 test year?

A: The Commission staff audit finds a revenue deficiency for the 2016 test year of about $10.4 million, or 1.48% of 2016 test year electric revenues under current rates.

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

A: Yes. At the request of Commission staff, NSPW conducted five cost of service studies based on the Commission staff audit forecast of 2016 test year revenue requirements. These five studies differ with respect to the methods used to classify and allocate production capacity and distribution plant costs. Below is a brief description of each of the five studies using the Company's nomenclature for these studies:

- The "Method 1 COSS" classifies all production capacity costs as demand-related and allocates such costs on the basis of each class's contribution to the twelve monthly system peaks (12CP). In addition, the Method 1 COSS classifies distribution plant costs as customer- or demand-related on the basis of a minimum distribution system analysis.
- The "Method 2 COSS" differs from the Method 1 COSS in two respects. First, the Method 2 COSS classifies 60.1% of production capacity costs as demand-related and the remaining 39.9% as energy-related. Second, the Method 2 COSS allocates demand-related production capacity costs on the basis of each class's contribution to system peak in the four summer months (4CP).
- The "Method 3 COSS" differs from the Method 1 COSS only with respect to the use of a 4CP allocator to allocate production capacity costs.
- The "Method 4 COSS" modifies the Method 1 COSS by classifying 40% of production capacity costs as demand-related and the remaining 60% as energy-related.
- The "Method 5 COSS" modifies the Method 4 COSS by classifying all distribution plant costs, other than for meters, as demand-related and allocates such demand-related costs using a 12CP allocator.

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

A: As noted above, based on Commission staff's audit, the revenue deficiency for the 2016 test year is about $10.4 million, or 1.48% of 2016 test year electric revenues under current rates. For each of the five 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 2016 test year electric revenues under current rates for each class.

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

`	Method 1 COSS	Method 2 COSS	Method 3 COSS	Method 4 COSS	Method 5 COSS
Residential	1.25%	1.09%	2.25%	-0.73%	-7.12%
Small C&I[2]	1.46%	-0.56%	0.56%	-2.08%	-3.94%
Medium C&I	0.17%	0.20%	0.15%	0.87%	3.00%
Large C&I	2.29%	2.84%	1.79%	4.16%	9.74%
Lighting	-3.37%	-7.68%	-13.15%	3.95%	-21.09%
Total System	1.48%	1.48%	1.48%	1.48%	1.48%

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

A: Of the five studies, the Method 5 COSS allocates production capacity and distribution plant costs in a fashion that most reasonably reflects each class's

[2] For cost-allocation purposes, the Company includes rate schedules Mp-1, Mz-3, and interdepartmental sales in the Small C&I customer class.

responsibility for such costs.[3] Specifically, the Method 5 COSS achieves reasonable consistency with cost-causation by:

- Classifying production capacity costs in a manner that reasonably reflects the drivers of plant investment under typical generation expansion planning practice.
- Allocating demand-related production capacity costs on the basis of each class's contribution to the twelve monthly system peaks.
- Classifying all distribution plant costs, other than for meters, as demand-related.

A. Classification of Production Capacity Costs

Q: How are production capacity costs classified as demand- or energy-related in the five audit studies?

A: As noted above, the Method 1 and Method 3 studies classify 100% of production capacity costs as demand-related. The Method 2 COSS classifies 60.1% of production capacity costs as demand-related and the remaining 39.9% as energy-related. Finally, the Method 4 and 5 studies classify 40% of production capacity costs as demand-related and the remaining 60% as energy-related.

Q: Do the Method 1 and Method 3 studies reasonably classify production capacity costs?

A: No. These two studies inappropriately classify all production capacity costs as demand-related, as if production capacity costs were incurred solely for the

[3] However, as I discuss below, the Method 5 COSS under-allocates distribution plant costs to the residential and small C&I classes by allocating demand-related distribution plant costs based on a 12CP allocator.

purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements. This classification approach is inconsistent with investment decision-making under typical generation expansion planning practices, where plant investment choices are driven by both reliability and energy requirements. As explained in NARUC's *Electric Utility Cost Allocation Manual*:

> For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.[4]

Q: Does the Method 2 COSS rely on one of the "energy weighting methods" described in the NARUC manual to classify production capacity costs?

A: Yes. The Method 2 COSS uses the Peak and Average Demand method to classify production capacity costs.[5] Under this approach, the percentage portion of production capacity costs classified as demand-related is determined by the ratio of peak demand to the sum of peak and average demands.[6]

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[4] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, pp. 38-39.

[5] *Id.*, pp. 57-58.

[6] This is mathematically equivalent to splitting production capacity costs between demand- and energy-related portions in proportion to the ratio of peak to average demand. If the demand-related percentage portion is calculated as peak demand / (peak demand + average demand), then the energy-related portion is average demand / (peak demand + average demand). The ratio of demand-related to energy-related portions then works out to peak demand / average demand. (The ratio of energy-related to demand-related portions is thus equal to system load factor.)

Q: Do you have any concerns regarding the Peak and Average Demand method?

A: Yes. The Peak and Average Demand method tends to overstate the demand-related portion of production capacity costs because it does not recognize that peaking capacity is less expensive than baseload or intermediate capacity on a per-kilowatt basis. Instead, the Peak and Average Demand method splits production capacity costs into demand- and energy-related portions based solely on the relationship of peak to average demands, as if peaking and non-peaking capacity have equivalent unit investment costs.

Q: Is there a classification method that distinguishes between peaking and non-peaking investment costs?

A: Yes. The Equivalent Peaker method distinguishes between investments in peaking plant and investments in baseload or intermediate plant for classification purposes. Under the Equivalent Peaker method, 100% of peaking plant costs are classified as demand-related. The Equivalent Peaker method also classifies the portion of baseload or intermediate plant costs equivalent to peaking plant costs as demand-related, but classifies the remainder of baseload or intermediate plant costs *in excess of peaking plant costs* (i.e., capitalized energy costs) as energy-related.[7]

The Equivalent Peaker method more reasonably reflects cost-causation than the Average and Peak Demand method because it classifies production capacity costs consistent with the drivers of plant investment under typical generation expansion planning practices. Specifically, investments in peaking plant are appropriately classified as demand-related, since peaking units would

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

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 should be classified as energy-related, since these incremental costs are typically incurred to minimize the total cost of meeting an increase in energy requirements.

Q: Did NSPW or Commission staff conduct an Equivalent Peaker analysis for the purposes of classifying production capacity costs in the Method 4 and 5 studies?

A: No. However, Commission staff conducted such an analysis in Docket No. 4220-UR-119.[8] The results of that analysis indicate that the demand/energy split assumed for the Method 4 and Method 5 studies more-reasonably reflects the drivers of plant investment than that derived using the Peak and Average Demand method for the Method 2 COSS.

B. Allocation of Demand-Related Production Capacity Costs

Q: How are demand-related production capacity costs allocated to customer classes in the five audit studies?

A: The Method 1, 4, and 5 studies allocate demand-related production capacity costs using a 12CP allocator. The 12CP allocator allocates demand-related production capacity costs on the basis of each class's contribution to the twelve monthly system peaks. As discussed above, demand-related production capacity costs are incurred for the purposes of meeting reserve requirements. Thus, a 12CP allocator allocates demand-related production capacity costs consistent

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[8] See Tr. Vol. Vol. I, Direct-PSC-Albrecht-5, Table A, columns 4 and 5 (Docket No. 4220-UR-119) (PSC REF#: 192672).

with the notion that the Company's planning reserve requirements are driven by system peaks in all months of the year.

In contrast, the Method 2 and 3 studies allocate demand-related production capacity costs on the basis of each class's contribution to system peaks solely in the four summer months. In these two audit studies, the 4CP allocator allocates demand-related production costs as if reserve requirements are driven by system peaks only in the four summer months.

Q: Which of these two allocators most reasonably reflects each class's responsibility for demand-related production capacity costs?

A: The 12CP allocator more reasonably reflects cost-causation than the 4CP allocator because the Company's annual reserve requirement is determined based on demand throughout the year, not just by demand in the four summer months.

Specifically, the Midcontinent Independent System Operator (MISO) determines the amount of capacity required for planning reserve based on the results of a loss of load probability (LOLP) analysis that considers the daily contribution of the Company's demand to annual loss of load expectation (LOLE).[9] Although lower than peak demands in the summer months, non-summer peaks can also contribute to annual LOLE and thus system reserve requirements at times when margins between available capacity and demand are tight. For example, the scheduling of plant maintenance during low-demand shoulder months can reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLE and reserve requirements.

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[9] Although MISO determines the amount of capacity required for planning reserve based on demand throughout the year, it expresses the Company's reserve requirement as the percentage margin of required capacity over 1CP demand.

Thus, the Company's investments in capacity to meet reserve requirements are driven by demand in every month, not just by summer peaks. Consequently, a 12CP allocator is a more reasonable measure of each class's contribution to the need for new reserve capacity than a 4CP allocator.

C. Classification of Distribution Plant Costs

Q: Please describe the methods used in the five audit studies to classify distribution plant costs.

A: The Method 5 COSS classifies all distribution plant costs, with the exception of meter costs, as demand-related. All other audit studies classify certain distribution plant costs as customer-related or demand-related based on a "minimum distribution system" analysis.

Q: Is one of these classification approaches more reasonable than the other?

A: Yes. The method used in the Method 5 COSS more reasonably classifies distribution plant costs than the minimum distribution system approach used in the other studies. As discussed below, minimum distribution system analyses typically produce classifications that are inconsistent with cost-causation and which result in an over-allocation of distribution plant costs to the residential and small C&I rate classes. As has been recognized in jurisdictions throughout the U.S., the method used in the Method 5 COSS offers a more reasonable alternative to minimum distribution system classification.[10]

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.

[10] Unlike the approach used in the Method 5 COSS, some jurisdictions classify all services costs as customer-related.

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., zero-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 a 2015 report on the Company's minimum system study, the Company used the minimum-intercept method to classify all distribution plant costs in Accounts 364 through 369.[11]

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

[11] "NSPW 2015 Minimal Distribution System Study," April, 2015. Provided in response to Commission Initial Data Request No. 3 (PSC REF#: 237246).

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-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.[12]

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.

[12] 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

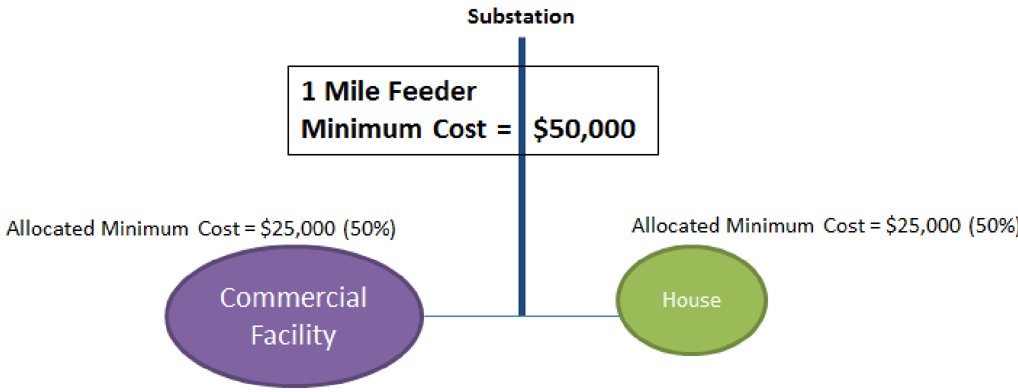
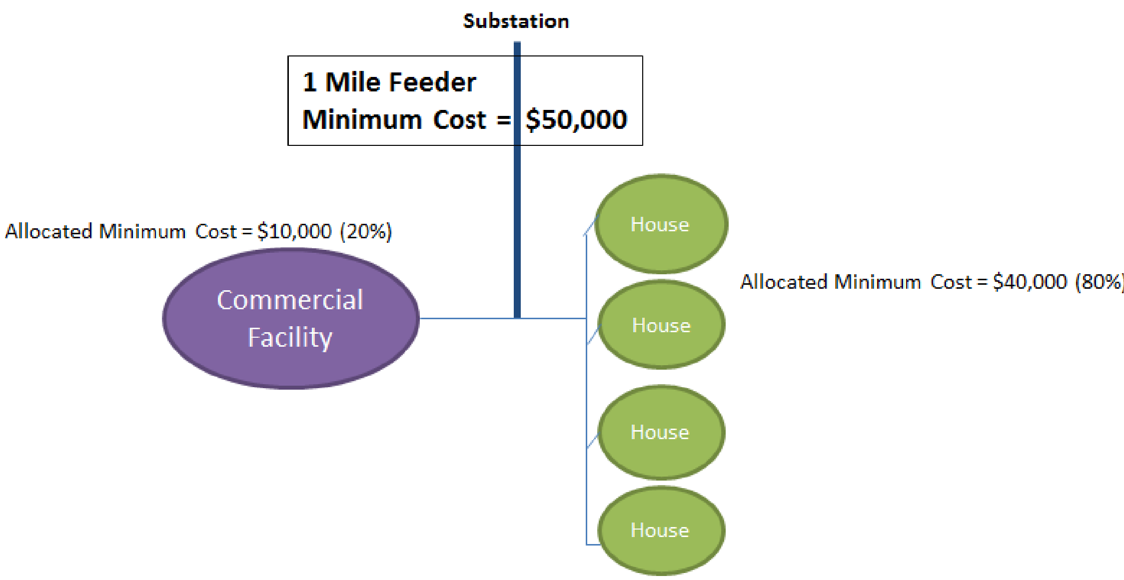


Figure 1b



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 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-intercept method?

A: Yes. 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.[13]

Alternatively, distribution plant costs (other than meters and services) could be classified using the approach adopted by Wisconsin Electric Power 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.[14] Under this approach, for example, if minimum-system costs were 50% of total distribution plant costs, then 75% of total costs would be classified as demand-related and 25% would be classified as customer-related.

[13] 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.

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

D. Allocation of Demand-Related Distribution Plant Costs

Q: How are demand-related distribution plant costs allocated in the five audit studies?

A: In all but the Method 5 COSS, demand-related distribution plant costs are allocated based on each class's non-coincident peak (NCP) demand.[15] In the Method 5 COSS, demand-related distribution plant costs are allocated using a 12CP allocator, i.e., in proportion to each class's contribution to the twelve monthly system coincident peaks.

Q: Do one of these allocators better reflect cost-causation?

A: Yes. The NCP allocator more reasonably reflects the effect of load diversity on distribution equipment loading and thus is more likely to reflect the drivers of distribution plant investment.

Q: How would use of the NCP allocator affect the allocation of demand-related distribution plant costs?

A: Using the NCP allocator rather than the 12CP allocator would increase the allocation of demand-related distribution plant costs to the residential and small C&I classes and decrease the allocation to the large C&I customer class.

In order to estimate the impact, I modified the spreadsheet model for the Method 5 COSS by substituting the NCP allocator for the 12CP allocator for the purposes of allocating demand-related distribution plant (and fixed O&M) costs. The effect of this modification on allocation of the 2016 test year revenue deficiency is shown in Table 2.

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[15] A class's NCP demand is the maximum demand for the class as a whole regardless of when that peak occurs. It is referred to as a "non-coincident" peak because a customer class may reach maximum demand at a different time than when the peak for the NSPW system as a whole occurs.

Table 2: Effect of NCP Allocator on Revenue Allocation

`	Method 5 COSS	Method 5 COSS with NCP Allocator
Residential	-7.12%	-3.59%
Small C&I	-3.94%	-2.75%
Medium C&I	3.00%	3.07%
Large C&I	9.74%	6.24%
Lighting	-21.09%	-10.96%
Total System	1.48%	1.48%

III. Base Revenue Allocation Proposal

Q: Given that the Method 5 COSS most reasonably reflects cost-causation, do you recommend that study's allocation of the 2016 test year revenue deficiency?

A: No. As the Commission has long held, cost of service studies are merely guides, and no one study perfectly captures cost-causation. It therefore would be appropriate to consider the results of all five of the audit cost of service studies (as well as my modification of the Method 5 COSS) for the purposes of allocating the 2016 test year revenue deficiency to customer classes.

Q: Based on the results of the five audit cost of service studies and your modification of the Method 5 COSS, how do you propose to allocate the 2016 test year revenue deficiency?

A: I recommend that revenues be allocated to customer classes as shown in Table 3. I developed my recommendation based on the directional results from the five audit studies and my modification of the Method 5 COSS, with the goal of narrowing the difference for all classes between the allocated revenue increase and the system average increase in order to avoid rate shock for any one class.

Table 3: Recommended Allocation of 2016 Test Year Revenues

	Current Revenue	Proposed Revenue	Revenue Increase	Percent Increase
Residential	250,403,194	252,281,218	1,878,024	0.75%
Small C&I	47,210,171	47,210,171	-	0.00%
Medium C&I	110,326,318	111,153,765	827,447	0.75%
Large C&I	288,511,531	296,210,601	7,699,070	2.67%
Lighting	6,234,786	6,234,786	-	0.00%
Total System	702,686,000	713,090,541	10,404,541	1.48%

As indicated in Table 3, I recommend that revenues for both the residential and medium C&I customer classes be increased by no more than 0.75%. I further recommend a 2.67% revenue increase for the large C&I customer class. Revenues for all other classes should be held constant at current levels.

I will include in my rebuttal testimony my proposal for allocating 2016 test year revenues to each of the residential and small C&I rate classes.

IV. Rate Design

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

A: The Company proposes to more than double the monthly customer charge for residential and small C&I customers from $8 to $18. According to Company witness Ms. Erwin, NSPW is proposing to sharply increase the customer charge in order to "better align its fixed customer charges with some of the fixed costs incurred by the Company…."[16]

Q: Which costs does NSPW contend are fixed?

A: According to Ms. Erwin, NSPW considers all production, transmission, and distribution costs that are classified as either demand-related or customer-related under the Method 2 COSS to be fixed.[17] Thus, NSPW considers only those costs classified as energy-related under the Method 2 COSS (primarily fuel and variable O&M) to be variable costs.

Q: Does the Company's Minnesota affiliate also consider all demand- or customer-related production, transmission, and distribution costs to be fixed?

A: No. According to testimony filed before the Minnesota Public Utilities Commission in a 2014 rate case, Northern States Power Minnesota (NSPM) considers only customer-related distribution costs to be fixed:

> There are generally two components to the fixed cost of service: service costs and facility costs. The service category includes the fixed costs of billing, meter reading, and customer service and accounting. The facility category includes the cost of the individual customer meter and service wire connection, and the minimum level of distribution facilities that are required to provide service. The Company's customer charge is designed to recover some of these fixed costs.[18]

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[16] Direct-NSPW-Erwin-3.

[17] At least in the short run. Ms. Erwin believes that demand-related generation, transmission, substation, pole, and conductor costs would be variable in the long run. See NSPW Response to 3-CUB/Inter-9. A copy of this response is attached as Ex.-CUB-Wallach-2.

[18] *Direct Testimony and Schedules of Steven V. Huso*, Exhibit SVH-1, Minnesota Public Utilities Commission Docket No. E002/GR-13-868, November 4, 2013, p. 14, attached hereto as Ex.-CUB-Wallach-3.

Thus, unlike the Company, NSPM does not consider production, transmission, or demand-related distribution costs to be fixed. Consequently, NSPM did not seek to recover such costs through a customer charge in its last rate case.

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

A: According to Ms. Erwin, the customer charge would have to increase to $80.55 per month – ten times the current level – in order to recover all costs allocated to the residential class under the Method 2 COSS that NSPW alleges to be fixed.[19] Thus, a residential customer charge of $18 per month would recover about 22% of the production, transmission, and distribution costs that NSPW considers to be fixed.

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

A: The customer charge would have to increase to $15.18 per month in order to recover all costs that NSPM considers to be fixed.[20] Thus, a residential customer charge of $18 per month would recover about 119% of the costs that NSPM considers to be fixed.

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[19] Direct-NSPW-Erwin-5, Table 1. These amounts are based on the Company's filed request for 2016 test year revenue requirements, not the Commission staff audit 2016 test year revenue requirements. Also see NSPW Response to 4-CUB/Inter-3. A copy of this response is attached as Ex.-CUB-Wallach-4.

[20] *Id*. See the results for Case C.

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 customer charge?

A: If the customer charge for the RG-1 rate class were increased to $80.55 per month, I estimate that the annual average energy charge (i.e., average over the summer and winter periods) would plummet from its current rate of 12.2¢/kWh to about 2.9¢/kWh.[21]

Q: Is the Company proposing to recover all allegedly fixed costs through the customer charge?

A: Not at this time. Instead, NSPW proposes to increase the customer charge to recover all distribution costs other than the portion of the costs for poles and conductors classified as demand-related based on the results of a minimum distribution system analysis.[22] These include the costs of customer services, meters, both customer-related and demand-related services and transformer costs, and customer-related poles and conductor costs.

However, according to Ms. Erwin, the Company does not want to foreclose the option to recover the remaining allegedly fixed costs through the customer charge in the future.

Q: Would it be appropriate to recover all allegedly fixed costs through the customer charge?

A: No. Such costs may appear "fixed" from the short-term perspective of utility accounting treatment since the revenue requirements associated with debt service and maintenance of sunk investments in any year is unlikely to vary

[21] My estimate is based on spreadsheet data provided in NSPW Response to 2-WIEG-3.

[22] Direct-NSPW-Erwin-9, Table 2.

much with load or sales in that year. However, as Ms. Erwin acknowledges, from the longer-term perspective of cost-causation and economic efficiency, plant capital and fixed O&M are variable with respect to customer usage.[23] Shifting recovery of such long-run marginal costs to the customer charge would seriously distort price signals since consumers would no longer benefit from actions that reduce usage and thus reduce plant and fixed O&M costs. Likewise, consumers would no longer be penalized for increased load. Consequently, recovering these long-run marginal costs through the customer charge would misleadingly and inefficiently signal to consumers that there is no economic gain or loss associated with changes in customer load.[24]

Q: Would it be reasonable to recover line transformer costs and customer-related poles and conductor costs through the customer charge, as the Company proposes?

A: No. If such costs were recovered through the customer charge, then the smallest residential or commercial customers (with the lowest cost to connect) would be required to pay the average of customer-related costs attributable to all sizes of customers in their customer class. In this case, if all customers were to pay the same customer charge regardless of size, small customers would subsidize larger customers' distribution costs.

This is most clearly the case with respect to the demand-related line transformer costs that NSPW proposes to recover through the customer charge

[23] The point here is not that the sunk costs of plants in ratebase are necessarily variable with usage, but that they represent the costs of future plant investments that would vary with customer load.

[24] In fact, shifting long-run marginal costs to the customer charge could necessitate further increases to customer charges in the future, in order to recover uneconomic plant investment required to meet demand growth resulting from misleading price signals.

since such costs vary directly with customer size. However, this is also the case with respect to the transformer, poles, and conductor costs classified as customer-related based on a minimum distribution system analysis. The customer-related cost per customer derived under a minimum distribution system analysis represents the minimum cost to serve an *average-usage* customer, not the minimum cost to serve any customer regardless of usage level. In fact, the minimum distribution cost per customer will vary with the usage of the customers served by the distribution equipment. Consequently, the true minimum cost to serve a customer with very little usage is likely to be less than the customer-related cost per customer.

For example, Ms. Erwin estimates a minimum (i.e., customer-related) cost for line transformers of $2.28 per *average-usage* customer per month.[25] Assuming that each transformer serves on average three residential customers, a monthly minimum cost of $2.28 per customer would equate to a monthly minimum cost of $6.84 per transformer.[26]

In contrast, the minimum transformer cost per *low-usage* customer is likely to be less than that for an *average-usage* customer, because each transformer could serve more low-usage than average-usage customers. For example, with a monthly minimum cost of $6.84 per transformer, the monthly minimum cost per low-usage customer would be only $1.14, or half that per average-usage customer, if each transformer could serve six low-usage customers.[27] I would

[25] Direct-NSPW-Erwin-5, Table 1.

[26] According to the Company's response to Commission Initial Data Request Electric Rates No.1 (PSC REF#: 23724), there are 64,780 line transformers serving 207,961 residential customers. Thus, each transformer serves about three average-usage customers.

[27] This example illustrates the fundamental conceptual flaw in the minimum-intercept method discussed above in Section III. If the minimum-intercept method estimates the minimum cost per

therefore expect the minimum distribution cost per low-usage customer to be less than the minimum distribution cost per average customer.

Q: What costs are appropriately recovered through the customer charge?

A: The customer charge is intended to reflect the incremental costs imposed by the continued presence of a customer who uses very little energy. Thus, the customer charge should not be expected to cover all customer-related costs for the average residential customer, but only the incremental cost to connect one more very small customer. Since the Company would probably not need to add secondary conductor or a transformer to connect a very small customer, incremental connection costs would be limited to installation and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer service expenses.[28]

Q: What is the incremental cost to connect a residential customer in the Company's service territory?

A: According to data provided in Table 1 of Ms. Erwin's direct testimony, the incremental cost of customer services, meters, and services (including the demand-related portion of services costs) amounts to $8.51 per customer per month.[29] Thus, the $18 per month customer charge proposed by the Company would overstate the minimum connection cost by more than a factor of two.

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transformer for a transformer that serves zero load, then the true minimum cost per customer must be zero since a transformer that serves zero load can serve an infinite number of customers with zero load.

[28] Remote residences might also require a line extension and a small transformer in order to connect to the distribution system.

[29] Direct-NSPW-Erwin-5, Table 1. The costs shown in Table 1 are based on the Company's filed request for 2016 test year revenue requirements, not the Commission staff audit 2016 test year

Q: How does the Company's proposal to increase the customer charge from $8 to $18 per month affect the RG-1 energy charge?

A: With the customer charge set at $18, the Company proposes to reduce the average annual energy charge from 12.2¢/kWh to 11.5¢/kWh in order to recover the 2016 test year revenue requirement allocated to the residential class.[30] If, instead, the customer charge remained at its current rate of $8, the energy charge would have to be increased to 12.8¢/kWh to recover the same allocated revenue requirement.[31] Thus, the average annual energy charge under the Company's proposal to increase the customer charge by $10 would be about 10%, less than the energy charge without the proposed increase to the customer charge.

Q: To what extent would the lower energy charge under the Company's proposal for the fixed charge dampen price signals for conservation?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term.

Most studies of electric price response have estimated the change in consumption that results from a change in the customer's average rate. For

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revenue requirements. However, I estimate that the incremental cost per residential customer is the same under either forecast of 2016 test year revenue requirements.

[30] My estimate is based on spreadsheet data provided in NSPW Response to 2-WIEG-3.This energy rate is based on the Company's filed request for 2016 test year revenue requirements, not the Commission staff audit 2016 test year revenue requirements.

[31] *Id.*

example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run average-rate elasticity estimates of about −0.35 on average across studies and long-run average-rate elasticity estimates of about −0.85 on average across studies.[32]

In contrast, some studies have examined the change in usage as a function of changes in the marginal rate paid by the customer.[33] The response to marginal-price incentives is typically lower than the response to average rates, but not insubstantial. Table 3 lists the results of seven studies of marginal-price elasticity over the last forty years.[34]

Table 3: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential energy rate?

A: From Table 3, it appears that –0.3 would be a reasonable mid-range estimate of the effect over a few years.

32 In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in average rates.

33 For a residential customer, that would be the energy rate.

34 The citations for these studies are provided in Ex.-CUB-Wallach-5.

Q: What would be a reasonable estimate of the effect on energy use from the 10% reduction to the RG-1 energy rate under the Company's proposal to increase the customer charge?

A: An elasticity of –0.3 and a 10% reduction in energy price would result in a 3% increase in energy consumption. This means that all else equal, residential load would be expected to increase by 3% over a several-year period as a result of implementing the Company's proposed fixed charge increase.

For comparison, I estimate that energy savings in 2014 from Focus on Energy residential programs amounted to about 1% of 2014 statewide residential sales. If we assume uniform percentage savings across utilities, the consumption increase due to the Company's proposed increase to the residential fixed charge (and the resulting decrease in the energy charge) would undo about three years of residential energy-efficiency savings in the Company's service territory.

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

A: The Commission should reject the Company's proposal to increase residential and small C&I customer charges. The Company's proposal would unreasonably shift costs to the customer 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 low-usage customers.

In contrast, the current customer charge reasonably reflects the incremental cost to connect customers. Consequently, residential and small C&I customer charges should not be increased from current levels.

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

A: As I noted in Section I, I will include in my rebuttal testimony proposed rate designs for the residential and small C&I rate classes that reflect my proposal for allocating the 2016 test year revenue deficiency and my recommendation to maintain customer charges at current levels.

Q: Does this complete your direct testimony?

A: Yes.