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-119

DIRECT TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
October 4, 2013

I. Introduction

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric-power industry since 1981. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the past thirty years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and management; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Ex.-CUB-Wallach-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have sponsored expert testimony in more than sixty federal, provincial, or state proceedings in the U.S. and Canada. In Wisconsin, I testified in Docket Nos. 6630-CE-302, 3270-UR-117, 4220-UR-117, 6680-FR-104, 3270-UR-118, 05-UR-106, 4220-UR-118, and 6690-UR-122. 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 31, 2013, Northern States Power Company of Wisconsin (NSPW or "the Company") filed an application to increase electric and gas rates for the 2014 test year. This testimony addresses the methods used by NSPW in its embedded electric class cost of service study (CCOSS) to allocate the 2014 test year electric revenue deficiency to the residential and small commercial rate classes, as described in the pre-filed direct testimony of Company witnesses Gerald W. Marx and Donald R. Dahl.

In addition, this testimony presents my proposed allocation to customer classes of the Commission staff audit forecast of the revenue deficiency for the 2014 test year. I expect that Commission staff will provide as part of its direct testimony in this proceeding the audit forecast of rate class billing determinants for the 2014 test year. On rebuttal, I intend to propose revenue allocations to each of the residential and small C&I rate classes, and rate designs for those rate classes to recover my proposed revenue allocations, once I have had the opportunity to review Commission staff's forecast of billing determinants.

Q: Are there any other issues in this case that you are reserving for rebuttal?

A: Yes. It is my understanding that Commission staff will be recommending adjustments to the Company's forecast of 2014 test year cleanup costs for the Ashland Manufactured Gas Plant. I intend to address these adjustments on rebuttal.

II. Cost Allocation

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

A: The Company is requesting that electric rates be increased on average by 6.5% in order to recover an expected revenue deficiency of $40.0 million in the 2014 test year. Of the total $40.0 million requested revenue increase, NSPW proposes to allocate about $19.2 million to residential and small C&I customers.[1] This amount represents a 7.0% increase over residential and small C&I revenues under current rates.[2]

Q: What is the basis for the Company's proposed residential and small C&I rate increase?

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[1] Ex.-NSPW-Dahl-3, Schedule 3.

[2] In its cost of service studies, the Company allocates costs separately to the "residential", "non-demand general service", and "lighting" customer classes. The residential customer class includes the Rg-1, Rg-2, Fg-2, residential VRE, and residential Cg-6 rate classes. The non-demand general service customer class includes the Cg-1, Cg-2, commercial VRE, Mp-1, and Mz-3 rate classes (along with interdepartmental sales). The lighting class includes the S-1 and Ms-1, -2, -3, -4, -6, and-7 rate classes. For purposes of the following discussion of the Company's cost of service studies, I follow the Company's convention by including all of these rate classes in the "residential and small C&I" customer class.

A: The Company conducted a number of cost of service studies that differed with respect to the methods used to classify and allocate production capacity costs. These studies vary the proportion of production capacity costs classified as either demand-related or energy-related, ranging from 100% demand-related and 0% energy-related to 57%/43% demand/energy. These studies then allocate demand-related production capacity costs based on class contribution to the average of either: (1) the twelve monthly peaks (12CP); or (2) the monthly peaks for the four summer months (4CP). Energy-related production capacity costs are allocated based on class contribution to either: (1) average system production costs (E10T); or (2) marginal system production costs (E8760E).

According to Company witness Mr. Dahl, NSPW relied primarily on the range of results from three of these cost of service studies as the basis for its proposed revenue allocation in this case. Table 1 provides the percentage demand/energy splits and allocators used to classify and allocate production capacity costs in each of these three studies. In addition, Table 1 shows the residential and small C&I percentage revenue increases for each of these three studies based on the Company's proposed revenue deficiency.

Table 1. Classification and Allocation of Production Capacity Costs

	Demand-Related Percent	Demand Allocator	Energy-Related Percent	Energy Allocator	Residential and Small C&I Revenue Increase
100% 12CP CCOSS	100%	12CP	0%	---	7.0%
60.7% 4CP / 39.3% E10T CCOSS	60.7%	4CP	39.3%	E10T	6.1%
60.7% 4CP / 39.3% E8760E CCOSS	60.7%	4CP	39.3%	E8760E	6.9%

Q: Do these three cost of service studies provide a reasonable basis for the allocation of the revenue deficiency to the residential and small C&I classes?

A: No. The range of results from these studies exceeds reasonable bounds, since all three studies allocate more production capacity costs and distribution plant costs to the residential and small C&I classes than is appropriate.

Q: How does the 100% 12CP CCOSS over-allocate production capacity costs to the residential and small C&I classes?

A: The 100% 12CP CCOSS classifies all production capacity costs as demand-related, implying that, from a generation planning perspective, production capacity costs are incurred solely for the purposes of meeting system reliability requirements. This assumption is inconsistent with investment decision-making under typical generation expansion planning practices, where plant investment choices are driven by both reliability and energy requirements.

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

The 100% 12CP CCOSS approach misclassifies these capitalized energy costs as demand-related. As a result, this cost of service study over-allocates capitalized energy costs to residential and small C&I rate classes, since these classes have lower load factors than the larger C&I classes.[3]

Unlike the 100% 12CP CCOSS, the 60.7% 4CP / 39.3% E10T and 60.7% 4CP / 39.3% E8760E studies classify a portion of production capacity costs as energy-related. However, I have classified the Company's production capacity costs using the "Equivalent Peaker" classification method, and the results of that analysis indicate that the 60.7% 4CP / 39.3% E10T and 60.7% 4CP / 39.3% E8760E studies classify more production capacity costs as demand-related than is consistent with the Company's investments in production capacity.[4]

Q: Please describe your Equivalent Peaker classification of the Company's production capacity costs.

A: I applied the Equivalent Peaker method in two different ways. Under the first approach, I estimate the demand- and energy-related portions of the Company's production capacity costs using the Company's forecast of gross plant and fixed O&M costs for the 2014 test year.[5] In this case, I calculated: (1) the average fixed cost per kW-yr for the Company's combustion turbines; and (2) the average fixed cost per kW-yr for the Company's entire generation portfolio.[6]

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[3] 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.

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

[5] The Company provided this cost data in its response to Interrogatory 2-CUB/RFP-2 (PSC REF#: 191152).

[6] Specifically, I calculated the average fixed cost per kW-year for combustion turbines by summing 2014 test year gross plant cost across all combustion turbines, applying an assumed 10% fixed-charge rate, adding 2014 test year fixed O&M costs for all combustion turbines, and then

The ratio of (1) to (2) gives the percentage of the Company's production capacity costs that are demand-related under this version of the Equivalent Peaker method.[7]

Using this approach, I estimate that 20% of the Company's production plant costs are demand-related and about 80% are energy-related.

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

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dividing by the total capacity of the combustion turbines. I calculated the average fixed cost per kW-year for the entire portfolio in the same fashion.

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

Using this approach, I estimate that 24% of the Company's production plant costs are demand-related and about 76% are energy-related.

Q: How do the Company's cost of service studies over-allocate distribution plant costs to the residential and small C&I classes?

A: The Company's cost of service studies classify certain distribution costs as customer-related or demand-related based on a minimum-system analysis. Minimum-system methods are generally unreliable and tend to misclassify demand-related costs as customer-related costs. As a result, cost allocations based on minimum-system classifications overstate the appropriate allocation of distribution costs to residential and small C&I customers.[8]

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

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

A minimum-size analysis attempts to estimate the cost to install the same number of units (e.g., poles, conductor-feet) as are currently on the system, assuming that each of those units are the smallest size currently used on the distribution system.

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

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

spans). The goal of this procedure is to estimate the cost of equipment required to connect existing customers, even if they had virtually no load.

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

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

A: According to a 1992 report on the Company's minimum system study, the Company used the minimum-size method to classify poles (Account 364) and line transformers (Account 368) and used the zero-intercept method to classify overhead conductors (Account 365), underground conduit (Account 366), underground conductors (Account 367), and services (Account 369).[9]

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

A: No. As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, these approaches are fundamentally flawed because minimum-system costs, however estimated, are neither properly classified as wholly customer-related nor demand-related.[10] Instead, Bonbright, Danielson, and Kamerschen argue that such costs are inherently "unallocable":

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs …, while it is also denied a place among the customer costs …, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable

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[9] Gerald W. Marx, "Minimal System Analysis", Northern States Power Company (Wisconsin), June 1, 1992. Provided in response to Commission Initial Data Request No. 3 (PSC REF #: 185524).

[10] In other words, these costs are not driven primarily by either changes in the number of customers or by changes in customer demand, but instead may depend on such factors as customer density or terrain.

> 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.[11]

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

In addition, the minimum-size and minimum-intercept methods suffer from specific problems that tend to produce unreasonable results. In a 1981 article, George Sterzinger identified a flaw in the minimum-size approach that could result in over-allocation of costs to the residential and small C&I classes.[12] The problem arises because the minimum-size method typically defines the minimum system to include equipment that would carry a large portion of the average customer's load. For example, assume that the minimum-size line transformer is large enough to cover the average load of residential customers. In this case, only those costs incurred for the minimum-size transformers are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method would not only allocate these minimum-size transformer costs to the residential class as customer-related costs, but would also inappropriately allocate a portion of the remaining costs for larger-sized transformers to residential customers as demand-related costs, even though the costs for these larger transformers were not incurred to serve residential load.

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

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

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

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

A: Yes. A reasonable and reasonably straightforward alternative approach, and one that has been used in other jurisdictions, would be to classify meters and services as customer-related and all other distribution plant costs as demand-related.[13]

[13] According to a study by the Regulatory Assistance Project, the method used in the Location Model to classify distribution plant costs is employed in more than thirty states. See Frederick

Q: Have you developed a cost of service study that classifies production capacity costs based on the Equivalent Peaker method and classifies all distribution plant costs other than meters and services as demand-related?

A: Yes. I developed a cost of service study ("CUB CCOSS") by modifying the Company's 100% 12CP CCOSS as follows:

- Classify production capacity costs as 30% demand-related and 70% as energy-related.
- Allocate demand-related production capacity costs using the 12CP allocator.
- Allocate energy-related production capacity costs and production expenses using the E10T allocator.
- Classify all costs in FERC Accounts 364 through 368 as demand-related and all costs in FERC Account 369 as customer-related.

Q: Why did you use the 12CP allocator to allocate demand-related production capacity costs?

A: The Company has traditionally relied on the 12CP allocator for its preferred cost of service studies, based on the recognition that peak demands in all twelve months of the year contributed to annual loss of load probability (LOLP) and thus system reserve requirements.[14] The 12CP allocator appropriately and reasonably reflects the fact that peak demands in all months have driven investments in demand-related production capacity.

Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, December, 2000, p. 30.

[14] See, e.g., Docket No. 4220-UR-116, *Direct Testimony of Gerald W. Marx*, p. 115 (PSC REF#: 115121) for an explanation of the basis for the Company's reliance on the 12CP allocator.

As far as I am aware, this proceeding is the first time that NSPW is using the 4CP allocator in its preferred cost of service studies. The Company now supports using the 4CP allocator based on the observation that the most-recent LOLP analysis by MISO shows that only the summer months contribute to annual LOLP for the MISO system.[15] The results of this LOLP study thus indicate that winter peak demands and capacity margins do not affect the need for new reserve capacity for the MISO system as a whole. In other words, according to the most-recent MISO LOLP study, excess winter capacity provides no reliability value to the MISO system.

The results of the MISO LOLP study are not adequate grounds for switching from the 12CP to the 4CP allocator. Unlike for the MISO system as a whole, excess winter capacity on the NSPW system has reliability value, because of the impact of the Company's system diversity agreements with Manitoba Hydro. These agreements require Manitoba Hydro to make capacity available to the Company during the summer months and the Company to do the same for Manitoba Hydro during the winter. As a result, in exchange for providing excess winter capacity to Manitoba Hydro, the Company receives capacity in the summer months which can be used to meet its summer reserve requirements. Thus, because of the diversity exchanges, excess winter capacity provides reliability value to the NSPW system in the form of exchanged reserve capacity imports in the summer months.

[15] See the Company's response to 2-CUB-Inter-6(a) (PSC REF#: 191149).

Q: Why did you use the E10T allocator rather than the E8760E allocator to allocate energy-related production capacity costs and production expenses?

A: I relied on the E10T allocator because the E8760E allocator inappropriately allocates *embedded* costs to classes based on a class's contribution to *marginal* costs. Compared to the E10T allocator, the E8760E allocator places disproportionate weight on class load during on-peak hours and thus overstates the share of total energy-related costs properly attributable to low load factor classes.

Q: Please describe the results of your cost of service study of the Company's forecast of 2014 test year revenue requirements.

A: Table 2 provides the portion of the Company's forecast of the 2014 test year revenue deficiency allocated to each of the customer classes in the CUB CCOSS and in the Company's three preferred cost of service studies. As indicated in Table 2, a much smaller share of the total 2014 test year revenue deficiency is allocated to residential and small C&I customers when production capacity and distribution plant costs are classified in a manner consistent with cost-causation principles.

Table 2. Allocation of NSPW Forecast of 2014 Test Year Revenue Deficiency

	CUB CCOSS	NSPW 100% 12CP CCOSS	NSPW 60.7% 4CP / 39.3% E10T CCOSS	NSPW 60.7% 4CP / 39.3% E8760E CCOSS
Residential and Small C&I	1.7%	7.0%	6.1%	6.9%
Medium C&I	9.9%	7.1%	7.4%	8.0%
Large C&I	10.8%	5.7%	6.6%	5.4%
Total System	6.5%	6.5%	6.5%	6.5%

III. Revenue Allocation and Rate Design

Q: Please describe the results of the Commission staff audit of electric revenue requirements.

A: The Commission staff audit forecasts a revenue deficiency for the 2014 test year of $23.8 million, or about 40% less than the Company's forecast.[16] Current rates would need to be increased on average by 3.8% to recover the 2014 test year revenue deficiency forecast by the Commission staff audit.

Q: Have you developed cost of service studies of the Commission staff audit forecast of 2014 test year revenue requirements?

A: Yes. Using the audit forecast of revenue requirements, I developed "audit" versions of the CUB CCOSS ("CUB AUDIT CCOSS") and of the Company's three preferred studies.

Q: Please describe the results of the CUB AUDIT CCOSS.

A: Table 3 provides a summary of the results of the CUB AUDIT CCOSS allocation of the audit revenue requirements. As indicated in Table 3, the Commission staff audit forecasts a revenue deficiency for the 2014 test year of about $23.8 million, or about 3.8% of 2014 test year electric revenues under current rates. Given that overall deficiency, the CUB AUDIT CCOSS shows a revenue *excess* of about $3.5 million for residential and small C&I customers. This revenue excess represents about 1.2% of 2014 test year revenues under current rates for residential and small C&I customers.[17]

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[16] NSPW Response to CUB-Vbl-092313 data request.

[17] In other words, residential and small C&I rates would need to be reduced on average by 1.2% to eliminate excess recovery of $3.5 million in the 2014 test year.

Table 3. CUB AUDIT CCOSS Results

	Current Revenues	Revenue Increase	Percent Increase
Residential and Small C&I	$285,218,173	($3,475,815)	-1.2%
Medium C&I	$93,249,070	$6,362,444	6.8%
Large C&I	$249,601,105	$20,888,362	8.4%
Total System	$628,068,348	$23,774,991	3.8%

Table 4 provides the share of the Commission staff audit forecast of the 2014 test year revenue deficiency allocated to each of the customer classes in the CUB AUDIT CCOSS and in the "audit" versions of the Company's three preferred cost of service studies.

Table 4. Allocation of Audit Forecast of 2014 Test Year Revenue Deficiency

	CUB AUDIT CCOSS	AUDIT 100% 12CP CCOSS	AUDIT 60.7% 4CP / 39.3% E10T CCOSS	AUDIT 60.7% 4CP / 39.3% E8760E CCOSS
Residential and Small C&I	-1.2%	4.1%	3.1%	4.0%
Medium C&I	6.8%	4.3%	4.5%	5.3%
Large C&I	8.4%	3.3%	4.3%	2.9%
Total System	3.8%	3.8%	3.8%	3.8%

Q: Based on the results of the CUB AUDIT CCOSS, how do you propose to allocate the Commission staff audit forecast of the 2014 test year revenue deficiency?

A: I provide my proposed revenue allocation for each customer class in Table 5. As can be seen by comparing Tables 3 and 5, I propose to increase revenues for the residential and small C&I customer class by 2.5%, even though substantial revenue reductions would be justified by the results of the CUB AUDIT CCOSS. On the other hand, I propose a substantially smaller revenue increase for the medium and large C&I classes than would be warranted from a cost-causation perspective. These deviations from cost causation are reasonable, since they allow for moderate rate increases for all customer classes and ensure that all classes' rate increases fall within a narrow band around the system-average rate increase.

Table 5. Recommended Revenue Allocation

	Current Revenues	Revenue Increase	Percent Increase
Residential and Small C&I	$285,218,173	$7,130,454	2.5%
Medium C&I	$93,249,070	$4,527,014	4.9%
Large C&I	$249,601,105	$12,117,523	4.9%
Total System	$628,068,348	$23,774,991	3.8%

Q: How would you recommend that any changes by the Commission to the Commission staff audit revenue requirements be allocated to customer classes?

A: I would continue to recommend that the Commission staff audit revenue deficiency be allocated as shown in Table 5, above. I would then recommend that the total-system *difference* between the Commission's revenue requirements and the Commission staff audit revenue requirements be allocated to customer classes in equal proportion, such that all customer classes would experience an equal percentage change in revenues due to the difference between the Commission's and the Commission staff audit revenue requirements.

For example, as indicated in Table 6, if the Commission were to increase the Commission staff audit revenue deficiency by $7 million, that increase would amount to a 1.1% increase in the Commission staff audit revenue requirements. In this case, I would recommend that the Commission staff audit revenue deficiency of $23.8 million be allocated as recommended in Table 5, above. I would further recommend the Commission's additional $7 million revenue deficiency be allocated to customer classes such that each class's revenues (after my recommended allocation of the Commission staff audit revenue deficiency) increase by a uniform 1.1%.

Table 6. Recommended Allocation of Hypothetical Commission Additional Revenue

	Current Revenues	Audit Revenue Increase	Audit Revenues	Commission Increase over Audit Revenues	Percent Increase over Audit	Total Increase over Current Revenues
Residential and Small C&I	$285,218,173	$7,130,454	$292,348,627	$3,139,467	1.1%	3.6%
Medium C&I	$93,249,070	$4,527,014	$97,776,084	$1,049,996	1.1%	6.0%
Large C&I	$249,601,105	$12,117,523	$261,718,628	$2,810,538	1.1%	6.0%
Total System	$628,068,348	$23,774,991	$651,843,339	$7,000,000	1.1%	4.9%

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

A: I will recommend specific rate designs for the residential and small C&I rate classes as part of my rebuttal testimony, once I have had the opportunity to review and evaluate Commission staff's audit forecast of rate class billing determinants. These rates will be designed to achieve the following objectives:

- Set rates for individual rate classes within the residential and small C&I customer class to achieve the recommended allocation of 2014 test year revenue requirements for the customer class as a whole (as shown in Table 5, above).
- Set rates for individual rate classes within the residential and small C&I customer class to reflect the relative allocations among these rate classes in the CUB AUDIT CCOSS.
- Maintain customer charges at current levels, as recommended by NSPW.

- Increase current energy rates for all of the individual rate classes by a uniform percentage in order to achieve my recommended revenue allocation for the residential and small C&I customer class in total.[18]

Q: Does this complete your direct testimony?

A: Yes.

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[18] I describe above a procedure for allocating to customer classes any modification to the Commission staff audit revenue requirement approved by the Commission. To the extent that the revenue allocation for the residential and small C&I customer class pursuant to this procedure is different than shown in Table 5, above, I recommend modifying the uniform percentage factor applied to current energy rates in order to achieve the modified revenue allocation for the residential and small C&I customer class as a whole.