**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF WISCONSIN**

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| Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates | Docket No. 4220-UR-118 |

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

October 19, 2012

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## 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 55 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, and 05-UR-106. 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 June 1, 2012, Northern States Power Company of Wisconsin (NSPW or "the Company") filed an application to increase electric rates by an average of either 6.7% or 7.2%, depending on the treatment of cleanup costs for a manufactured gas plant (MGP) and adjoining properties in Ashland, Wisconsin ("Ashland Site"). The 6.7% electric rate increase represents a revenue deficiency of $39.1 million for the 2013 test year. The Company proposes to increase residential electric rates on average by 6.9% in order to recover $15.2 million of the total $39.1 million revenue deficiency. For its natural gas utility, the Company is also requesting a rate increase of $5.3 million (4.9%) for Ashland Site cleanup costs.

This testimony addresses the following aspects of the Company's filing:

- The Company's proposal for amortizing and recovering through rates the cleanup costs for the Ashland Site, as described in the pre-filed direct testimony of Company witness David D. Donovan.

- The impact of the loss of municipal wholesale load on the revenue deficiency for 2013, as discussed in the pre-filed direct testimony of Company witnesses Donald F. Reck and Karl J. Hoesly.

- The methods used in the embedded electric class cost of service study (CCOSS) to allocate the proposed 2013 test year electric revenue deficiency to the residential class, as described in the pre-filed direct testimony of Company witnesses Gerald W. Marx and Donald R. Dahl.

**Q: Please summarize your findings and conclusions.**

A: Given current estimates of the costs to clean up the Ashland Site, the Company asserts that natural gas customers and shareholders will be harmed if costs are recovered pursuant to the Commission's current policy regarding recovery of MGP cleanup costs. In order to mitigate these alleged harms, NSPW proposes to revise the current policy with regard to the amortization of cleanup costs and the allowed return on unamortized balances. In addition, the Company proposes an alternative recovery mechanism where costs are shared equally between natural gas and electric customers.

There is too much uncertainty at this time regarding the magnitude, timing, or the appropriate ratepayer share of cleanup expenditures to reasonably determine either the harm to the Company from the Commission's current policy or the benefit from the Company's proposed revisions to that policy. What is certain, however, is that the Company's proposal would unreasonably shift the cleanup cost burden from shareholders to ratepayers. Consequently, the Commission should reject the Company's proposal to alter current policy and to recover Ashland Site cleanup costs of $5.3 million in 2013 test year natural gas or electric rates.

All ten of the Company's wholesale municipal customers have exercised their contractual rights to terminate their power-supply contracts with the Company by the end of 2012. The Company expects that the impact on the 2013 test year revenue deficiency from this loss of wholesale load will be significant. However, the Company could feasibly reduce this impact by selling generating capacity freed up by the termination of the wholesale municipal contracts. To the extent that this released capacity is excess to the system, the Company should seek to maximize revenues from the sale of such excess in the wholesale market.

Finally, 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, but relied primarily on the range of results from two of these studies as guidelines for setting electric rates. The range of results for residential rates from these two studies (i.e., 7.1% to 8.1%) exceeds reasonable bounds, since both studies allocate more production capacity costs and distribution plant costs to the residential class than is appropriate. Modifying the Company's cost of service study to include reasonable allocators for production and distribution plant costs with the Company's proposed revenue deficiency results in an increase to the residential class of 3.4%.

## II. Recovery of Ashland Site Cleanup Costs

**Q: How did the Company acquire the manufactured gas plant located at the Ashland Site?**

A: According to a complaint filed by the Company in federal district court, NSPW acquired the MGP as a result of a merger with the prior owner, Lake Superior District Power Company (LSDP), in 1986.[1] According to the Commission's final decision in Docket Nos. 3020-UM-100 and 4220-UM-100, this was a merger of corporate affiliates, with all common stock of both entities wholly owned by Northern States Power of Minnesota (NSPM).[2] As a result, the merger transferred ownership of the MGP site, along with the associated environmental liability, from one NSPM-owned entity to another.

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[1] *NSPW v. City of Ashland, et al.*, W.D. Wis. Case No. 12-CV-602, filed August 17, 2012, provided by NSPW in response to 2-CUB/Inter-1.

[2] Docket Nos. 3020-UM-100 and 4220-UM-100, Joint Findings of Fact, Conclusions of Law and Order (November 13, 1986) attached hereto as Ex.-CUB-Wallach-2.

**Q: Did the Company provide an estimate of the cost to clean up the Ashland Site as part of its merger application?**

A: Not as far as I am aware. In its merger application in Docket Nos. 3020-UM-100 and 4220-UM-100, the Company does not appear to have accounted for potential cleanup costs when it estimated merger net savings of $298,000 per year.[3] Nor is there any mention in the merger application or in the Commission's final decision of the potential environmental liability associated with ownership of the MGP site.

**Q: Was the Company aware of the environmental contamination at the Ashland Site at the time of the merger?**

A: I am unable to determine at this time whether NSPW was aware of any environmental contamination at the time of the merger, because the Company has refused to respond to CUB discovery regarding when the Company was first aware of contamination at the site or what due diligence efforts were undertaken prior to the merger to assess potential contamination at the site.[4]

**Q: Is there reason to believe that the Company would have been aware at the time of the merger of the potential for environmental contamination at the Ashland MGP site or adjoining property?**

A: Yes. As described in a decision by the Supreme Court of Minnesota in *Northern States Power Co. v. Fidelity and Cas. Co. of New York*, five years prior to the Company's filing of the merger application, NSPM was notified by the Minnesota Pollution Control Agency of groundwater contamination at one of its Minnesota MGP sites.[5] In response, NSPM began an evaluation of potential remedial

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[3] Docket Nos. 3020-UM-100 and 4220-UM-100, Application, Exhibit A-11, filed July 8, 1986. Provided by the Company in response to 3-CUB/RFP-22 and attached hereto as Ex.-CUB-Wallach-3.

[4] See NSPW response to 3-CUB/Inter-7 (PSC REF #: 174309).

[5] See *Northern States Power Co. v. Fidelity and Cas. Co. of New York*, 523 N.W.2d 657, 659 (1994). The decision states:

measures in 1984, and then informed its insurers of the potential liability in February of 1987. Given the experience of its corporate parent by 1986, NSPW should have been aware at the time of the merger that ownership of the Ashland MGP site could create an environmental liability for the Company.

**Q: What is the Company's current estimate of the cleanup cost for the Ashland Site?**

A: According to Company witness Mr. Donovan, the Company currently expects to spend about [redacted] million (net of insurance payments) by 2016 on the cleanup of the Ashland Site.[6] The Company's estimate includes costs for the Upland Area portion of the Ashland Site (UA Site) for which a Consent Decree has been entered in federal district court, [redacted].

**Q: To what extent will these costs be shared with other parties that are potentially responsible for cleanup of the Ashland Site?**

A: That is uncertain at this time. According to Mr. Donovan, the Environmental Protection Agency has identified three potentially responsible parties (PRP) besides the Company: the City of Ashland, Wisconsin Central Limited Railroad, and the Soo Line Railroad Company. The Company has engaged in settlement negotiations with these other PRPs, which, [redacted]. Subsequent to filing its application in this proceeding, NSPW filed suit against these other PRPs in federal district court.

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In 1981, the [Minnesota Pollution Control Agency] discovered that the groundwater at [two adjacent sites along the Straight River in Faribault, MN] was contaminated with coal tars and spent oxide waste; it subsequently urged NSP to investigate remedial measures. NSP did so from 1984 to 1987.

[6] Direct-NSPW-Donovan-7c, Table 1 (PSC REF #:166916).

**Q: How does the Company propose to recover Ashland Site cleanup costs from ratepayers?**

A: Starting with the 2013 test year, NSPW proposes to set rate recovery based on the Company's forecast of annual cleanup expenditures for each test year.[7] Revenue requirements for each test year would be determined based on a ten-year amortization of estimated annual cleanup expenditures and a return on unamortized balances at the Company's cost of debt.

The Company also proposes two options for recovery of cleanup revenue requirements. One option would be to recover all revenue requirements from natural gas customers. The other option, and the option preferred by NSPW, would be to recover half of the cleanup revenue requirements from natural gas customers and half from electric ratepayers.

**Q: What is the Commission's current policy regarding recovery of MGP cleanup costs?**

A: Attached as Ex.-CUB-Wallach-4 is a copy of a Commission staff memorandum dated February 19, 2009 and entitled "General Guidelines for Accounting and Rate Treatment of Manufactured Gas Plant Site Clean-Up Costs" that summarizes the Commission's current policy on MGP cleanup costs. Under the current policy, the Company could seek recovery of this year's actual spending to clean up the Ashland Site in a rate case filing for test year 2014 and of 2013 and 2014 actual spending in a rate case filing for test year 2016. In each of these rate cases, the Commission would determine the extent to which the Company's MGP cleanup expenditures were prudently incurred and then set the amortization period for

[7] Under the Company's proposal, rate recovery for the 2013 test year would reflect forecasted expenditures for both 2012 and 2013.

those prudently incurred costs.[8] The current policy does not allow recovery of any carrying costs on unamortized balances.

**Q: How does the Company's proposal differ from the Commission's current policy regarding recovery of MGP cleanup costs?**

A: My understanding is that the Company's proposal differs from the Commission's current policy in the following major respects:

- The Company proposes immediate recovery of estimated costs, while Commission policy requires deferred recovery of actual, prudently incurred costs.
- The Company proposes amortization of annual estimated costs over a ten-year period, whereas Commission policy allows amortization over four to six years.
- The Company proposes recovery of carrying costs at the cost of debt, while Commission policy precludes recovery of any carrying costs.

**Q: Why does the Commission require deferred recovery with no allowance for carrying costs?**

A: As described in its final decision in Docket No. 4220-UR-117, the Commission adopted the current policy in order to ensure that shareholders and ratepayers both share responsibility for prudently incurred MGP cleanup cost expenditures:

> Current Commission policy, which has been in place for many years, uses a process that defers MGP site remediation costs as they are actually incurred. The deferral of MGP site cleanup costs allows the Commission to (1) determine if these costs meet its guidelines before they are recovered in rates, and (2) shift a portion of the cost burden to the utility's shareholders with a multiple-year amortization of the deferral and no rate recovery of the carrying costs on the unamortized deferred balances. The recovery policy is designed to share responsibility for the MGP site

[8] The Commission staff memorandum states that "an amortization period of four to six years is appropriate but materiality should be taken into consideration."

cleanup between customers and shareholders by requiring customers to pay for the cost of the cleanup over a four- to six-year time period.[9]

**Q: Would the Company's proposal upset the level of cost sharing achieved under the Commission's current policy?**

A: Yes. The Company's proposal would dramatically shift more of the cost burden from shareholders to ratepayers.

Based on data provided in the Company's response to 3-CUB/RFP-17, I have estimated the present-value cost to ratepayers of recovery of Ashland Site cleanup costs (as currently estimated by the Company) under the Commission's current policy and under the Company's proposal.[10] As indicated in Table 1, the present-value cost to ratepayers under the Commission's current policy would be about $ million. In contrast, the Company's proposal would increase the cost burden on ratepayers by about % to approximately $ million.

I also show in Table 1 the ratepayer share of the total cost burden under the Commission's current policy and under the Company's proposal, where the total cost burden is expressed as the present value of the Company's forecast of annual cleanup expenditures.[11] As indicated in Table 1, the Company's proposed modifications to the Commission's current policy would substantially increase ratepayers' share of cleanup costs from % to %.

**Table 1: Ratepayer Share of Ashland Site Cleanup Costs**

| Recovery Mechanism | Present-Value Ratepayer Cost ($M) | Ratepayer Share of Expensed Cost |
|---|---|---|
| Current Policy | | % |
| NSPW Proposal | | % |
| Expensed to Rates | | ------- |

[9] Docket No. 4220-UR-117, *Final Decision*, pp. 23-24 (December 22, 2011) (PSC REF #: 157438).

[10] I set the discount rate at the Company's weighted average cost of capital for the purposes of this calculation.

[11] In other words, I derive the total cost burden as the present-value cost to ratepayers if annual cleanup expenditures were expensed to rates.

**Q: Why does the Company propose to modify the Commission's policy in this case?**

A: According to Mr. Donovan, the current estimate of the cost to clean up the Ashland Site is so large relative to the size of the Company's gas utility that recovery pursuant to the Commission's current policy will result in excessive increases in customer bills and damaging reductions in Company earnings. Specifically, based on its current estimate of the cleanup costs, NSPW estimates that recovery under the Commission's current policy would increase average natural gas bills in 2018 by about [redacted] % and reduce the Company's return on equity by "[redacted]."[12]

**Q: Is the Company's proposal a reasonable approach to mitigating customer rate impacts?**

A: No, because it substantially shifts costs from the Company's shareholders to its ratepayers. As discussed above, on a present-value basis, the Company's proposal increases the amount recovered from ratepayers for the Ashland Site cleanup by more than [redacted] % compared to cost recovery under the Commission's current policy.

**Q: Are there other options for recovering Ashland Site cleanup costs that would moderate customer rate impacts without substantially increasing costs to ratepayers?**

A: Yes. For example, costs could be amortized over more years than is called for under the Commission's current policy. Figure 1 below is a reproduction of Figure 1 from Mr. Donovan's direct testimony with the addition of a line showing the impact of applying the Commission's current policy with a 10-year amortization period rather than 6 years.

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[12] Direct-NSPW-Donovan-15c, ll. 8-9 (PSC REF #:166916).

**Figure 1 – Confidential**

[redacted]

Figure 1 above shows that, as with the Company's proposal, amortizing costs over a longer period tends to smooth out annual rate impacts. However, in contrast with the Company's proposal, costs to ratepayers would not increase significantly because no carrying costs would be charged to ratepayers.

However, the Commission need not make a decision on altering the amortization period at this time. Instead, the Commission can determine the appropriate amortization period for each year's expenditures at the time that the Company seeks rate recovery for that year's expenditures and based on the Commission's determination regarding the prudence of such expenditures and other material considerations.

**Q: Is the Company's forecast of the earnings impact of the Commission's current policy a reasonable basis for changing that policy?**

A: No. The Company's earnings forecast relies on speculative assumptions regarding future values for a number of key financial parameters, such as ratebase cost, capital structure, and authorized return on equity. Similarly, components such as revenue from sales and operations and maintenance costs may vary from the Company's projections. As a result, there is considerable uncertainty around the Company's forecast of the earnings impact over the next ten years.

Even if the Company's forecast were to prove accurate, the Company has overstated its impact. The Company's forecasted data shows that the Company's return on equity would be reduced by "[redacted] as the Company claims.[13] That same data also shows that under the Commission's current policy, if the Company's forecast were correct, its return on equity would be reduced by less than [redacted] basis points, on average, over the entire [redacted] forecast horizon.[14] The Company has not shown that a reduction of this magnitude would impede access to capital markets, increase the Company's cost of financing, or depress the Company's or its parent's equity return below levels necessary to attract equity investments.

**Q: What do you recommend with regard to the Company's proposal for recovering Ashland Site cleanup costs?**

A: The Commission should reject the Company's proposal to revise the Commission's current policy and to recover cleanup costs of $5.3 million in the 2013 test year.

Instead, the Commission should continue its current policy and defer recovery of each year's expenditures until the following biennial rate case. Rather than relying on speculative impacts as the Company currently proposes, the

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[13] See NSPW response to 3-CUB/RFP-17 (PSC REF #: 174320), excerpt included as Ex.-CUB-Wallach-5; Direct-NSPW-Donovan-15.

[14] See Ex.-CUB-Wallach-5.

Commission in each subsequent rate case can determine the prudence of actual spending in prior years and whether and to what extent recovering such expenditures pursuant to current policy harms customers or shareholders.

## III. Loss of Wholesale Municipal Load

**Q: Why will the Company no longer be serving wholesale municipal load in 2013?**

A: According to Company witness Mr. Reck, all ten of the Company's wholesale municipal customers have exercised their contractual rights to terminate their power-supply contracts with the Company by the end of 2012. As a result, NSPW will no longer serve about 110 MW of wholesale load starting in the 2013 test year.

**Q: How will this loss of wholesale municipal load affect the cost to serve Wisconsin retail load?**

A: According to Company witness Mr. Hoesly, the loss of wholesale municipal load affects the jurisdictional allocation of production and transmission costs between NSPM and NSPW load, and then between NSPW Wisconsin and NSPW Michigan retail load. Specifically, the loss of wholesale load on the NSPW system will reduce the allocation of NSP system production and transmission costs to NSPW and shift those costs onto NSPM customers. On the other hand, the loss of wholesale load will increase the allocation of NSPW-jurisdictional production and transmission costs to Wisconsin and Michigan retail load, since retail load will now be responsible for the portion of NSPW-jurisdictional costs that had previously been allocated to wholesale municipal customers.

**Q: What is the overall impact of the loss of wholesale municipal load on the Company's revenue deficiency for the 2013 test year?**

A: Mr. Hoesly characterizes the loss of wholesale load as a “major cost driver” of the requested rate increase for the 2013 test year.[15] However, the Company has not explicitly estimated the impact of the loss of wholesale load on the revenue deficiency for the 2013 test year, because the impact is “difficult to quantify in terms of revenue requirements.”[16] Instead, according to Mr. Hoesly, the impact is reflected implicitly in the calculation of the overall revenue deficiency for the 2013 test year.

**Q: If the Commission so desired, how could NSPW derive the incremental impact of the loss of load on the revenue deficiency for the 2013 test year?**

A: In order to quantify the impact, the Company would first have to estimate the jurisdictional allocation of 2013 test year production and transmission costs between NSPM and NSPW assuming no loss of wholesale load on the NSPW system. The Company would then have to estimate the allocation of NSPW-jurisdictional production and transmission costs among Wisconsin retail, Michigan retail, and wholesale municipal load, again assuming no loss of wholesale municipal load. Finally, the incremental impact on the revenue deficiency could be derived by taking the difference in Wisconsin-retail 2013 test year revenue requirements for the case assuming the loss of wholesale municipal load and for the case assuming no loss of wholesale load.

**Q: How might NSPW reduce the incremental impact from the loss of wholesale municipal load?**

A: The termination of the wholesale municipal contracts will free up generation capacity that had been dedicated to serving load under these contracts. To the extent that this released capacity is excess to the system, the Company should make best efforts to sell such excess in the wholesale market. Revenues from any

[15] Direct-NSPW-Hoesly-5, ll. 3-11 (PSC REF #:166901).

[16] Direct-NSPW-Hoesly-6, ll. 15-16.

such market sales, whether recovered through the fuel-adjustment process or reflected in base rates, would serve to moderate the incremental impact from the loss of wholesale municipal load.

## IV. Cost Allocation

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

A: The Company is requesting that electric rates be increased on average by 6.7% in order to recover an expected revenue deficiency of $39.1 million in the 2013 test year (assuming no recovery of Ashland Site costs from electric customers). Of the total $39.1 million requested revenue increase, NSPW proposes to allocate $15.2 million to residential customers.[17] This amount represents a 6.9% increase over residential revenues under current rates.

**Q: What is the basis for the proposed residential rate increase?**

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 varied the proportion of production capacity costs classified as either demand-related or energy-related, ranging from 100% demand-related and 0% energy-related to 0%/100% demand/energy.

According to Company witness Mr. Dahl, NSPW relied primarily on the range of results from two of these cost of service studies as the basis for its proposed revenue allocation in this case. The upper end of the range for the residential revenue increase (i.e., 8.1%) is derived with a CCOSS that classifies all production capacity costs as demand-related ("100% Demand COSS"), while the lower end of the range for the residential class (i.e., 7.1%) is based on a CCOSS that classifies 57.2% of production capacity costs as demand-related and the remainder as energy-related ("57.2%/42.8% Demand/Energy CCOSS"). In both of

[17] Ex.-NSPW-Dahl-2, Schedule No. 1 (PSC REF #:166908).

these studies, demand-related production capacity costs are allocated to customer classes on the basis of each customer class's contribution to the average of the twelve monthly system coincident peaks ("12CP").

**Q: Do these two cost of service studies provide a reasonable basis for the allocation of the revenue deficiency to the residential class?**

A: No. The range of results from these two studies exceeds reasonable bounds, since both studies allocate more production capacity costs and distribution plant costs to the residential class than is appropriate.

**Q: How do these two studies over-allocate production plant costs to the residential class?**

A: The 100% Demand 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.

Unlike in the 100% Demand CCOSS, the 57.2%/42.8% Demand/Energy CCOSS classifies a portion of production capacity costs as energy-related. However, based on an Equivalent Peaker analysis I conducted in Docket No. 4220-UR-117, it appears that the 57.2%/42.8% Demand/Energy CCOSS classifies more production capacity costs as demand-related than is consistent with the Company's investments in production capacity.

The Equivalent Peaker method classifies all investments in peaking plant 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 then classifies baseload or intermediate plant costs in *excess of peaking plant costs* (so-called "capitalized energy" costs) as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

In Docket No. 4220-UR-117, I applied the Equivalent Peaker method to the Company's investments in production capacity and determined that the Company's classification of production capacity costs as 38.4% demand-related and 61.6% energy-related fell within a reasonable range.[18]

**Q: How do the 100% Demand and 57.2%/42.8% Demand/Energy studies over-allocate distribution plant costs to the residential class?**

A: These studies classify 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 customers.

**Q: How does the Company allocate distribution plant costs to customer classes?**

A: The Company first classifies distribution plant costs (FERC Accounts 364 through 369) as either demand-related or customer-related based on a minimum system analysis.[19] The Company then allocates demand-related costs based on class non-coincident peaks and customer-related costs based on number of customers.[20]

**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 zero-intercept method.

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[18] Docket No. 4220-UR-117, Direct Testimony of Jonathan Wallach, p. D2.34, ll. 2-4 (PSC REF #: 154438).

[19] All distribution substation costs are considered to be demand-related, while all meter costs are considered to be customer-related.

[20] Customer-related line-transformer costs are allocated using a weighted customer allocator.

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 zero-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, 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 (FERC 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).[21]

**Q: Do minimum system approaches 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

[21] Gerald W. Marx, "Minimal System Analysis", Northern States Power Company (Wisconsin), June 1, 1992. Provided in response to Commission filing requirement 25G (PSC REF #: 165626).

as wholly customer-related nor demand-related.[22] 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 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.[23]

Residential 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 zero-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 class. 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

[22] 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.

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

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.

The zero-intercept method avoids the over-allocation problem associated with the minimum-size approach. However, the zero-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 zero-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 provides zero load. A system designed to connect customers but provide 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 services as customer-related and all other distribution plant costs as demand-related.

**Q: Have you estimated the impact on revenue allocations if the Company were to classify distribution costs in this fashion?**

A: Yes. I modified the CCOSS model inputs for the 57.2%/42.8% Demand/Energy CCOSS relating to distribution plant classifications in order to simulate the classification of all costs in FERC Accounts 364 through 368 as demand-related and of all costs in FERC Account 369 as customer-related. This alternative classification approach dramatically reduces the revenue increase allocated to the residential class relative to the allocation in the Company's version of the 57.2%/42.8% Demand/Energy CCOSS. In the Company's version, with distribution costs classified on the basis of a minimum-system analysis, the allocation of the revenue deficiency increases residential revenues by 7.1%. In contrast, the residential revenue increase is only 3.8% in the 57.2%/42.8% Demand/Energy CCOSS with all distribution costs (other than meters and services) classified as demand-related.

**Q: At the Company's current revenue requirement increase request of 6.7%, what do you conclude with respect to a reasonable alternative to the Company's CCOSS results in this proceeding?**

A: The range of results from the 100% Demand and 57.2%/42.8% Demand/Energy cost of service studies do not provide a reasonable basis for the allocation of the revenue deficiency to the residential class.

Instead, a reasonable result would be based on a CCOSS ("Alternative CCOSS") that classifies production capacity and distribution plant costs as follows:

- Classify production capacity costs as 40% demand-related and 60% energy-related.

- Classify all distribution plant costs, other than for meters and services, as demand-related. Classify all meters and services costs as customer-related.

Based on the Company's proposed revenue deficiency, the Alternative CCOSS yields the range of percentage increases in customer-class revenues reported in Table 2. As shown below, for the residential class, a reasonable result for NSPW's cost of service study would be 3.4%.

**Table 2: Revenue Increases by Customer Class**

| Customer Class | Alternative CCOSS |
|---|---|
| Residential | 3.4% |
| Small General | 2.4% |
| Total Medium | 10.0% |
| Total Large | 9.5% |

**Q: Does this complete your direct testimony?**

A: Yes.