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DEPARTMENT OF PUBLIC UTILITIES

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Investigation by the Department on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 804, 805, 780, 781, 780/781A, 784, 782, 783, 785, 786, 787, 790, 788, 793, 793A, 792, 794, 795, 796, 803, 797, 798, 799, 800, 801 and 802, filed with the Department on December 14, 1990 to become effective January 1, 1991 by Western Massachusetts Electric Company.

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I. INTRODUCTION

On December 14, 1990, Western Massachusetts Electric Company ("WMECo" or "Company") filed with the Department of Public Utilities ("Department") tariff schedules of proposed rate changes, M.D.P.U. Nos. 780 through 788, 790, and 791 through 805, to become effective January 1, 1991. The revised rates and charges were designed by the Company to increase its revenues collected in base rates by a net of $43.5 million, or 11.9 percent. The rate proposal is based on a historic test year ending June 30, 1990. On December 20, 1990, the Department suspended the rates and charges until July 1, 1991, in order to allow further investigation into the propriety of the proposed increase.

WMECo supplies retail electric service to more than 190,000 customers in over fifty cities and towns in four western counties of Massachusetts. The Company is a wholly-owned subsidiary of Northeast Utilities ("NU"). WMECo, the Connecticut Light and Power Company ("CL&P"), and Holyoke Water Power Company ("HWP") are the operating subsidiaries of the NU system. Other wholly-owned subsidiaries of NU provide substantial support services to the system companies. Northeast Utilities Service Company ("NUSCo") supplies centralized accounting, administrative, data processing, engineering, financial, legal, operational, planning, purchasing, and other services to the system companies. Other NU subsidiaries include Northeast Nuclear Energy Company ("NNECo"); Charter Oak

Energy, Inc.; HEC, Inc.; Rocky River Realty Company and the Quinnehtuk Company, the last two of which are real estate companies.

The Company's original revenue increase request of $55.1 million consists of three components. First, the Company proposed a $44.6 million increase to its cost of providing services to customers, of which $7.5 million represented increases in expenditures in its conservation and load management ("C&LM") program, and $4.1 million represented a transfer to base rates of costs associated with Hydro Quebec Phase II purchases. Second, the Company requested $5.7 million to cover changes in rate base, primarily increases in transmission and distribution plant. Third, the Company requested an increase in its return on equity from 12.5 percent to 13.7 percent, resulting in an additional increase in revenues of $4.8 million dollars. As discussed infra, the Company submitted a partial settlement to the Department on April 26, 1991, requesting a revenue increase of $18.0 million net of costs associated with Hydro Quebec Phase II and the Company's C&LM programs. The Company's C&LM programs are being reviewed in a pending proceeding before the Department. Western Massachusetts Electric Company, D.P.U. 91-44 ("D.P.U. 91-44").

The Department last granted the Company a rate increase in Western Massachusetts Electric Company, D.P.U. 89-255, issued June 29, 1990 ("D.P.U. 89-255"). In that Order, which was based on a test year ending June 30, 1989, the Department found that the Company was entitled to a retail rate increase of $20,664,054.

Several parties petitioned to intervene in this proceeding. Intervenor status was accorded to the Attorney General of the Commonwealth ("Attorney General") and to the Kimberly-Clark Corporation, Monsanto Company, Mead Corporation, and International Paper (collectively, "Industrial Intervenors").

The Commission designated Elaine McGrath, Esq., and Paul Szymanski, Esq., as hearing officers for the case. Dan Greenberg, Sean Hanley, Marla Simon, Catherine Wolfram, and Kevin Brannelly of the Electric Power Division of the Department provided technical assistance to the Commission.

The Department conducted public hearings in the Company's service territory in Pittsfield on February 11, 1991; in Springfield on February 12, 1991; and in Greenfield on February 13, 1991. Several government representatives and numerous customers of the Company appeared at these hearings and expressed their concerns. The government representatives included Representative Christopher J. Hodgkins, Representative Stanley Rosenberg and a member of Representative Carmen Buell's staff speaking on her behalf. The comments received at these public hearings included concerns about the size of the Company's requested return on equity given prevailing economic circumstances in the service area and the impact of the Company's acquisition of Public Service Company of New Hampshire ("PSNH"). The Department also received testimony at the public hearings on the frequency and size of the proposed increase in light of the fact that the five-year amortization of the Company's Millstone 3 expenses concluded with the previous rate case, D.P.U. 89-255.

Fifteen days of evidentiary hearings on the Company's rate application commenced at the Department on March 1, 1991, and concluded on April 10, 1991. In support of its filing, the Company presented direct prefiled testimony of several witnesses: Bernard Fox, president and chief operating and financial officer of WMECo; Robert Abair, vice president and director of WMECo; John Roman, director of revenue requirements for NUSCo; Malcolm Harris, Sr., associate professor of finance at St. John's University; Claus Berthold, manager of cost of service and load research for NUSCo; Michael Delphia, supervisor of generation planning studies; Charles Roncaioli, manager of rate analysis; and James Aikman, an expert witness who prepared a depreciation rate study. The Industrial Intervenors presented the testimony of two expert witnesses, Alan Rosenberg and Samuel Dwyer.

II. JOINT MOTION FOR APPROVAL OF A PARTIAL SETTLEMENT

A. Terms of the Settlement

On April 26, 1991, the Company and the Attorney General submitted a "Joint Motion For Approval of A Partial Settlement" and an accompanying "Partial Settlement Agreement" ("Partial Settlement"). The Industrial Intervenors did not participate in the Partial Settlement or its negotiation but indicated on May 1, 1991 that they did not object to the Settlement. The Department approved the Partial Settlement on May 3, 1991. The Partial Settlement resolved all issues concerning the level of the Company's revenue requirement by allowing the Company to collect additional base revenues of $18.0 million. The Partial Settlement also determined certain issues relative to the treatment of depreciation rates and the residential low-income discount. By its terms, depreciation rates accrue as set forth in an Appendix to the Partial Settlement (Parital Settlement, Appendix A), and the Company agreed not to seek modification of the depreciation expense accrual rates in its next base rate case.

The Partial Settlement provides that the Company will expand the low-income discount to include recipients of Fuel Assistance. The sole rate design modification contemplated by the Partial Settlement is that the compliance rates will be designed to recover the total revenue deficiency resulting from the low-income discount, which will be based upon the most recent number of actual recipients and a reasonable projection of the number of new recipients qualifying through the Fuel Assistance program.

The Department Order approving the Partial Settlement noted in its discussion of the design of the low-income discount that the limited nature of this modification "does not substantially restrict the Department's consideration of the unresolved rate structure issues including the level of discount, the mechanics of rate implementation, the expected level of participation, and the allocation of the amount of revenues to be collected from the remaining ratepayers." Order Approving Settlement, p. 4.

The Partial Settlement did not address the effect of the Company's proposal to include increased C&LM expenses and Hydro-Quebec Phase II expenses in base rates, and left these open for the Department's separate consideration. As discussed supra, the expenses associated with the Company's C&LM programs are being reviewed in a separate proceeding before the Department, D.P.U. 91-44. Additionally, the Partial Settlement proposed no resolution to any cost allocation or rate design issues, except for the limited modification of the low-income discount.

B. Motion To Implement The Partial Settlement As Of June 1, 1991

On May 6, 1991, the Company filed a Motion to Implement the Partial Settlement as of June 1, 1991 ("Motion") because of financial hardship. On May 8, 1991, the Industrial Intervenors filed an objection to the Company's Motion. The Attorney

General took no position on the Motion (Attorney General Letter of May 8, 1991). Hearing Officer McGrath denied the Company's Motion in a summary ruling on May 15, 1991. On May 17, 1991, the Company filed an Appeal of the Hearing Officer Ruling ("Appeal") and a Response to the Industrial Intervenors' Objection ("Response"). The Department treated the Company's motion as a request for interim rate relief and found that the Company had not met the stringent standards for that relief. The Department further found that "[t]he use of such a device as a contested motion to implement a partial settlement before the suspension deadline, at the 11th hour in a rate case, cannot substitute for the procedure for seeking interim rate relief." Appeal of Hearing Officer Denial of Motion to Implement WMECo's Partial Settlement As of June 1, 1991, p. 7. The Department, therefore, sustained the Hearing Officer's ruling and denied the Company's request to implement the revenue requirements increase a month before the end of the suspension period. Id.

III. EXPENSES

A. Background

The Department has approved a Partial Settlement Agreement concerning issues relating to the Company's total revenue requirement, described supra. The $18.0 million annual base revenue increase called for by the Partial Settlement is net of the costs associated with Hydro-Quebec Phase II transmission and net of increased C&LM expenses. In its initial filing, WMECo proposed to include expenses associated with both of these items in base rates (Exh. WM-12). The Company contended that all of the expenses associated with both Hydro-Quebec Phase II transmission and C&LM would normally be recovered through the fuel charge. In this way, the Company concludes, rolling the costs of these items into base rates would not have an overall impact on customers' bills (id., p. 2).

B. Hydro-Quebec Phase II Transmission Expenses

The Company has been recovering its expenses associated with Hydro-Quebec Phase II transmission on a quarterly basis through its fuel charge since December, 1990. Western Massachusetts Electric Company, D.P.U. 90-8D, p. 9 (1990). The Company's fuel charge for June, July and August 1991, approved by the Department in Western Massachusetts Electric Company, D.P.U. 91-8B (1991), reflects the Company's projection that Hydro-Quebec Phase II transmission expenses will be incorporated in base rates as a result of the Order in this docket. The issue, therefore, before the Department is whether the Company in fact should collect those expenses in base rates or whether it should continue to recover those expenses through the fuel charge.

WMECo's Hydro-Quebec Phase II transmission expenses are part of the terms of contracts between WMECo and four companies: New England Power Company ("NEPCo"), Boston Edison Company ("BECo"), New England Hydro-Transmission Electric Company ("Mass. Hydro") and New England Hydro-Transmission Corporation ("NH Hydro"). All of the contracts expire in either 2019 or 2020 (Exh. WM-12, Rev. Sch. C-3.5). Under the contracts, the Company makes monthly support payments in proportion to its allocated share of the transmission facilities. Power began to flow from Hydro-Quebec over the Phase II transmission facilities in November 1990 on a limited basis under an interim arrangement. A 10-year firm energy contract with Hydro-Quebec is scheduled to become effective in July 1991. The Department reviewed and approved the transmission support arrangement as well as the firm energy contract in Hydro-Quebec Phase II, D.P.U. 86-247 (1987).

In its initial filing, the Company proposed to include its annual transmission expenses associated with the second phase of the Hydro-Quebec project in base rates (Exh. WM-12, Sch. C-3.5; Tr. XII, p. 29). Following the precedent set in Western Massachusetts Electric Company, D.P.U. 86-280-A (1987), the Company provided updated expenses associated with the transmission contracts based on an annualization of the most recent invoices. The sum of the annualized April 1991 invoices is $4,611,000 (Exh. WM-12, Rev. Sch. C-3.5). However, the amount eligible for inclusion in base rates is $4,316,000 or $4,611,000 less $295,000 that was booked during the test year for expenses for the Hydro-Quebec Phase II contracts (id., Rev. WP C-3.5).

The Company indicated that it was providing the updated information concerning the Hydro-Quebec Phase II payments so that these costs could be incorporated in base rates (Company Reply Letter, p. 1). Neither the Attorney General nor the Industrial Intervenors addressed the rate treatment of the Hydro-Quebec Phase II expenses on brief or in their statements of position on the Partial Settlement.

In Western Massachusetts Electric Company, D.P.U. 1300 (1983), the Department established a standard treatment for long-term contracts for the purchase or sale of transmission services. In that case the Department found that "revenues and expenses from all contracts for transmission of capacity, that is, contracts which fix, in megawatts, the amount of power to be transmitted for a period in excess of one year, shall be included in base rates." D.P.U. 1300, p. 71 (1983). The Department finds that the Company's contracts with NEPCo, BECo, Mass. Hydro and NH Hydro for Hydro-Quebec Phase II transmission services comport with the standards set by the Department in

D.P.U. 1300 (Exh. WM-12, Sch. C-3.5).[1] Therefore, $4,316,000 shall be added to the increase in the revenue requirement specified by the Partial Settlement to reflect the expenses associated with the Hydro-Quebec Phase II transmission contracts.

C. Conservation and Load Management Expenses

In its intial filing, the Company estimated its 1991 C&LM expenses would be $13,638,000, representing an increase of $13,128,000 above the level of C&LM expenses included in the test year for the period July 1989 through June 1990 (Exh. WM-12, Sch. C-3.2). The $13,128,000 adjustment represented an increase of $7,510,000 above what was allowed in base rates by D.P.U. 89-255 for the period July 1990 through June 1991 (Tr. XII, p. 28, citing Exh. WM-12, p. 3). The annual base rate revenue increase called for by the Partial Settlement is net of the increased annual C&LM expenditures, i.e., net of the $7,510,000 increase that the Company originally projected.

On June 6, 1991 the Company updated its projected C&LM expenses to reflect its most recent 1991 budget (Exh. AG-94). The updates show that the Company is projecting to spend $16,023,000 on C&LM in 1991, rather than the $13,638,000 projected in its initial filing (id.). Based on the update,

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1 The power agreement with Hydro-Quebec is a firm energy contract rather than a capacity contract. WMECo, however, has a fixed share of the transmission facilities and the energy contract is designed to reduce the Company's capability responsibility proportionate to its transmission entitlement. The Department recognized the capacity value of the Hydro-Quebec Phase II project in Hydro-Quebec Phase II, D.P.U. 86-247, page 21 (1987).

$9,895,000 is eligible for inclusion in base rates, representingthe adjustment for increased C&LM expenses beyond what was allowed in base rates by D.P.U. 89-255.

The ratemaking treatment of C&LM expenditures is considered in depth in D.P.U. 91-44. In that case, the Department finds that the rate treatment for direct C&LM expenses shall be consistent with the treatment ordered in the Company's previous C&LM preapproval case, Western Massachusetts Electric Company, D.P.U. 89-260.[2] Specifically, pursuant to D.P.U. 91-44, direct expenses for C&LM shall be collected through base rates and any reconciliation for expenses above or below what is reflected in base rates shall be reconciled through the Company's fuel adjustment charge ("FAC"). D.P.U. 91-44, Sec. IV. In the instant proceeding, therefore, $9,895,000 shall be incorporated into base rates.

Adding Hydro-Quebec Phase II transmission expenses ($4,316,000) and incremental C&LM expenses ($9,895,000) to the annual base rate increase called for by the Partial Settlement ($18,000,000) brings the total annual base rate increase to $32,211,000.

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2 In D.P.U. 91-44, the Department also considers the rate treatment of two other C&LM-related expenses: a 1991 C&LM incentive and a Fixed Cost Recovery Adjustment. Consistent with D.P.U. 89-260, the Department finds those expenses shall be collected through the Company's FAC.

IV. RATE STRUCTURE

A. Rate Structure Goals

Rate structure is the level and pattern of prices that customers are charged for use of utility service. There are two steps in developing a utility's rate structure: cost allocation and rate design. Cost allocation entails assigning a portion of a utility company's total costs to each rate class. Rate design entails determining a set of prices for each rate class that is projected to produce revenues to support the allocated costs including the allowed return on equity and associated income taxes. The Department's goals for utility rate structures are efficiency, simplicity, continuity, fairness, and earnings stability.

In order to permit the development of a rate structure that meets the Department's efficiency objective, the cost allocation process should determine an overall revenue requirement for each class that reflects the costs a company incurs in serving that class. Cost allocation comprises five tasks. The first task is to allocate costs according to function. In this step, costs are defined as being associated with either the production, transmission or distribution function of providing service. The second task is to classify expenses in each functional category according to the factors underlying their incurrence. Thus, the expenses are classified as demand-, energy-, or customer-related. The third task is to identify an allocator which is most appropriate for costs in each classification within each function.

The fourth task is to allocate all of the company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total cost of serving each rate class. The fifth and final task is to compare the cost of serving each rate class to the revenues produced by each rate class during the test period based on existing rates. If the difference between these amounts is relatively small, the total revenue increase or decrease may be allocated among all rate classes to equalize rates of return and to ensure that each class pays for the costs it imposes. If the differences between the allocated costs and test year revenues are significant for at least some rate classes, the revenue increase or decrease may, for reasons of continuity, be allocated to reduce differences in rates of return without equalizing them in a single step.

In order to promote the Department's goals for rate structure, rate design must meet two objectives. First, subject to the rate continuity objective discussed above, it should produce a set of rates for each rate class which generate revenues covering the cost of serving that class. Second, rate design should be based on marginal cost. Economic theory indicates that marginal-cost-based prices tend to lead to the efficient allocation of resources.

There are four steps in rate design. First, a company must perform a marginal cost study which estimates a company's marginal costs. Second, marginal costs are converted into rates for each rate class. Third, the marginal-cost-based rates are reconciled with the total class revenue requirement by adjusting the most demand-inelastic portion of that rate. Fourth, the resulting rate structure is compared with the existing rates. If it is found to represent a change that violates the goal of continuity for certain customers within the rate class, the existing rates must be adjusted to move rate design toward marginal-cost-based rates in a manner that reflects the goal of rate continuity for those customers. Massachusetts Electric Company, D.P.U. 89-194/195, pp. 200-201 (1990); Cambridge Electric Light Company, D.P.U. 89-109, pp. 22-24 (1989); Western Massachusetts Electric Company, D.P.U. 89-255, p. 88 (1990); Boston Edison Company, D.P.U. 1720, pp. 112-120 (1984).

B. Cost Allocation

1. Introduction

In this proceeding, WMECo has proposed to allocate the Company's total revenue requirement to equalize rates of return among rate classes (Exh. WM-10, p. 3). This treatment is consistent with the Department decision in D.P.U. 84-25 (1985) and thereafter (id.). The Company filed a single system-wide cost of service study ("COSS") that contains jurisdictional costs, total retail costs, and costs by rate schedule (Exh. WM-15).

2. Allocation of Embedded Production Plant Costs

a. The Company's Proposal

The Company states that it proposes to allocate embedded power production capacity- and energy-related costs on the basis of allocators developed using the probability of dispatch ("POD") method (Exh. WM-14, p. 5). According to Mr. Berthold, manager of cost of service and load research for NUSCo, the POD method used by WMECo is consistent with the method accepted by the Department in D.P.U. 86-280 (1987), D.P.U. 87-260 (1988), D.P.U. 88-250 (1989), and D.P.U. 89-255 (1990) (id.).

In the Company's last rate case, the Department approved the "modified peaker" version of the POD. The Industrial Intervenors raised a number of issues, including the argument that the modified peaker POD failed to produce fuel symmetry. The Department also recognized that some of the methods proposed by intervenors regarding fuel symmetry issues may have had merit, and directed the Company to investigate such merits in its next rate case. The fuel symmetry issue relates to the fact that the POD allocates capacity costs on a unit-specific basis and thus unequally per KW to any given hour, while it allocates total fuel costs equally per KWH to all hours. The Department recognized that this difference in the allocation of the capacity and energy costs of a given plant could produce a mismatch between capacity and energy allocations. To produce fuel symmetry, then, if a particular class were assigned a higher mix of baseload plant in a given hour, it would also be assigned a lower unit fuel cost in that hour. Conversely, if a class were assigned a relatively high mix of peaking plant in that hour, it would be assigned a higher unit fuel cost in that hour. See Western Massachusetts Electric Company, D.P.U. 89-255, p. 92, 94, 98 (1990). In response to this directive, the Company proposes in this case to employ what it considers to be enhancements to the POD (Exh. WM-14, p. 2).

According to the Company, there are three differences between the "enhanced" POD method in this filing and the modified peaker version of POD approved in the Company's last rate case. First, the Company abandoned the "PEAKMOD" adjustment to the POD that had been incorporated to address an unreasonably high allocation of costs to off-peak periods. Second, so-called "reliability-related" costs were segregated from other gross plant costs and allocated separately (id., p. 14). Third, a so-called "base and remaining" method was used to allocate the POD-developed capacity and energy costs according to relative use in time periods.

In the modified peaker POD, the Company segregated production costs into two categories: the costs of the Company's peakers and the costs of its non-peaker plants. The costs of the Company's peakers were spread to peak hours; the costs of non-peakers were spread to all hours in which the plant in question was likely to operate; energy costs were spread to the hours in which plants were operating.

In this case the Company segregated production costs into five categories: (1) "reliability-related" capacity costs; (2) "remaining" capacity costs for continuously dispatched units; (3) "remaining" capacity costs for cycling units; (4) energy costs for continuously dispatched units; and (5) energy costs for cycling units (Exh. WM-14, Appendix A, p. 18). These categories are described more fully below.

The Company followed the ten steps presented below in applying the "enhanced" POD method:

(1) NU system hourly loads for the test year ending June 30, 1990 were employed to develop a set of 576 hourly load probability distributions for representative weekday and weekend days of each month.

(2) To assure that the Company's production cost model, PRODIS, properly reflected the operation of the Northfield Mountain Pumped Storage Facility ("Northfield"), a series of load modifiers were developed for Northfield. The total system load curve was adjusted by subtracting these load modifiers to derive a net curve to be satisfied by run-of-the-river, private power producers, and conventional thermal plants.

(3) The most likely dispatch sequence under normal operating conditions was developed for the test year.

(4) The probability or likelihood of dispatching each unit was then calculated for the typical hours in each month using the PRODIS model. These probabilities for each unit were then normalized to sum to 100 percent within the test year.

(5) "Reliability-related" costs were identified and allocated to hours by multiplying the revenue requirements for a hypothetical combustion turbine (i.e., NU's least capital intensive source of capacity) by the normalized probabilities of exceeding the system peak ("probability of peak") in each hour.

(6) Each unit's normalized probability of dispatch (from step 4) for each hour was multiplied by its remaining revenue requirements for that hour, computed as the current cost of the unit's capacity less the cost for reliability allocated to that hour in step 5.

(7) Each unit's total capacity costs were further assigned to either a "pumping" or "other" class in order to reassign pumping "class" costs to the hours when Northfield serves customer energy needs.

(8) The total capacity revenue requirements resulting from the preceding steps were multiplied by WMECo's monthly Northeast Utilities Generation and Transmission ("NUG&T") percentage capacity cost responsibility in order to determine WMECo's revenue requirements.

(9) Energy costs were computed by unit and by time period utilizing the same dispatch sequence used for capacity cost allocation.

(10) Capacity and energy costs by time period were allocated to customer classes based upon a measure of class load in that given time period in the following manner:

a. "Reliability-related" costs were allocated according to the relative class contribution to peak day loads.

b. "Continuously running" plant costs remaining after removal of the "reliability" costs of such plant were allocated based on each class' relative "entitlement" to baseload plant output. "Entitlement" was defined as the class' percentage of total annual sales times capacity of the "continously running" units, capped at the class' actual load in any given typical hour.

c. Costs of "cycling" units, remaining after removal of the "reliability" costs for such plants, were allocated based on relative loads for typical hours, reduced by the class' "baseload entitlement."

(Exh. WM-14, Appendix A, pp. 5-7, 12-19).

b. Positions of the Parties

i. The Industrial Intervenors

The Industrial Intervenors assert that while the Company's "enhanced" POD is an improvement over the modified peaker POD, it is still non-reflective of cost-causation (Industrial

Intervenors Brief, p. 9). According to the Industrial Intervenors, the "enhanced" POD gives the entire weight in its cost allocation to energy use and almost no weight to the cost-causative role of contribution to peak loads (id.).

According to the Industrial Intervenors, the POD can produce undesirable rate and pricing signals (id., p. 14). One of these problems is the asymmetric allocation of fuel and capacity costs. Another problem is that there are higher capacity costs allocated to some off-peak hours than to on-peak hours (id.). The Industrial Intervenors argue that, although off-peak hours might bear some capacity cost responsibility, it is illogical that the cost is higher than on-peak hours. They assert that basing rates on this allocation could make off-peak sales appear undesirable and stimulate on-peak sales (id., p. 15).

The Industrial Intervenors assert that there are three modifications that should be made to the Company's "enhanced" POD method (id.). First, they recommend an adjustment to the Company's calculated cost for a peaking unit. According to their witness, Mr. Dwyer, the cost of a peaker used to measure the reliability aspect of generators should be based on the equivalent available capacity, not the nominal capacity, thereby recognizing scheduled and unscheduled outages (id., pp. 15-16). This adjustment would increase the cost of the hypothetical peaker from $69.96 per KW per year to $83.25 per KW per year (id.).

The Industrial Intervenors' second recommendation is to add "reliability" costs for Northfield and NEPOOL purchases. Mr. Dwyer claims that WMECo inappropriately modeled the costs for Northfield as "remaining" costs only. No reliability-related costs were assigned for its usable capacity. Since Northfield Mountain can supply a significant portion of WMECo's peak loads, Mr. Dwyer claims it should be modeled with a reliability component to reflect this aspect of its operation (id., pp. 16-17).

The third adjustment the Industrial Intervenors suggest is to modify the input to the POD model so that the model's total output of "base," "remaining" and "reliability" costs equals NU's total annual revenue requirements for its generating plants (id., p. 18). According to Mr. Dwyer, these three adjustments would allow total annual revenue requirements for input in the POD to equal its output (id., p. 17).

The Industrial Intervenors advocate additional modifications relying on the testimony of Mr. Rosenberg. They propose to temper the results of the POD with what Mr. Rosenberg calls a "conventional slice of the system 3 CP allocation method" (id., p. 18). Mr. Rosenberg recommends giving the allocator developed in the 3 CP study a 25 percent weighting and the POD allocator from the Company's study a 75 percent weighting in the calculation of the production plant allocator (id., p. 19). According to Mr. Rosenberg, this approach to cost allocation allows each class to be allocated equal percentages of each generating unit. He recommends the 3 CP method, asserting, first, that it accurately reflects the three predominant peaks on the Company's system: winter morning, winter evening and summer; and second, that it best reflects the NUG&T agreement by which NU allocates the costs to WMECo (id.).

The Industrial Intervenors claim that the Company's "enhancements" are only a slight improvement over prior POD methods (Industrial Intervenors Reply Brief, p. 2). The Industrial Intervenors recommend that if the "enhanced" POD is approved by the Department, it should be further modified with Mr. Dwyer's changes (id.).

ii. The Attorney General

The Attorney General recommends that the Department reject the Company's changes to the modified peaker POD method approved in past cases (Attorney General Brief, p. 4). He urges the Department to uphold its prior findings, arguing that the modified peaker POD is the best method for reflecting cost causation, because it links the cost allocation to the customer's actual consumption by generating unit and it accurately allocates the capitalized energy benefits of fuel-saving plant (id., citing Cambridge Electric Light Company, D.P.U. 89-109, pp. 28-29 (1989)). The Attorney General asserts that the Company's proposed "enhancements" are an abandonment of the POD's principles (id., p. 4).

According to the Attorney General, the only component of the methodology which resembles the POD model is its use of a dispatch model, and the Attorney General claims furthermore that it does not use the dispatch model the way the POD method requires. The Attorney General outlines three ways in which the "enhanced" POD departs from the POD model. First, he argues that the "enhancement" makes a distinction between baseload and cycling units and allocates them differently, rather than allocating all plant costs to hours based on the probability the plant will be dispatched. Second, he asserts that for each typical time period the "enhancement" allocates the plant that is designated as baseload based on relative annual class average demands (or load in each typical low-load hour, whichever is lower) rather than according to relative loads in the particular hours of plant dispatch. Third, he claims that the Company incorrectly uses the dispatch model to allocate the plant designated as cycling, "based on each class' contribution to the 'Probability of Peak'" (id., pp. 4-5, citing Tr. VIII, p. 32).

The Attorney General states that there are four specific flaws in the Company's proposed method (id., pp. 5-7). First, he claims that the Company's distinction between "baseload" and "cycling" plant is wholly arbitrary. Second, he argues that the Company's plant categorizations wrongly assume that plants are always fully available. Third, he maintains that the Company's "enhancements" may lead to unstable results depending on how units are classified. Fourth, he asserts that the Company's "enhancements" do not reflect system planning and cost causation (id.).

First, the Attorney General states that the Company's proposed method arbitrarily distinguishes between baseload and cycling plant, by assuming that any plant which is dispatched at least 90 percent of the time is continuously running. This assumption, according to the Attorney General, is incorrect because it has the result of defining all must-run facilities (including all nuclear units) as baseload and all dispatchable fossil-fuel units (such as Mt. Tom) as cycling. The Attorney General contends that in fact WMECo has dispatchable fossil-fuel units that are used to meet energy needs, not just peak requirements, as he argues the Company's method seems to assume (id., p. 5).

Second, the Attorney General points out that the Company's plant categorizations depend on a model which assumes that units are fully available when it derives the percentage of time dispatched. According to the Attorney General, this causes the Company's method to treat equal units in an unequal fashion (id.).

Third, the Attorney General claims that the Company's "enhancements" may lead to unstable results, because a unit classified as cycling in one study could become baseload in the next (id., p. 6). The Attorney General asserts that this change in classification could occur because the higher the load and load factor and the lower the percentage of system capacity composed of must-run units, the greater the dispatch of cycling units. The Attorney General claims that under the Company's method, the change in unit classification could have a significant effect on the resulting cost allocation (id.).

The Attorney General asserts that the modified peaker POD method is more stable, because when the model dispatches a unit more frequently, the costs of the unit are assigned to more hours. The Attorney General claims that the Company's model, which involves more frequent dispatch of a unit, may lead to a complete change in the basis of cost allocation. The Attorney General therefore argues that the enhancement does not reflect system planning and cost causation (id.).

Fourth, in the Attorney General's opinion, the Company's "enhancement" to the traditional modified peaker POD method allocates plant to customer classes based upon customer class load profile characteristics, rather than on the class' contribution to system load (id., p. 6). Thus, the Attorney General claims that the Company's "enhancement" does not reflect system planning and cost causation. He points out that Mr. Berthold testified that utilities plan the installation of plants for on a system-wide basis, not for individual customer classes as though each were on a separate system (id., p. 7, citing Exh. WM-14, Appendix A, p. 1). The Attorney General argues that it is not evident that, under the Company's method, the units designated as "baseload" would have sufficient capacity and output to meet the sum of the customer class loads used to allocate such a plant (id., pp. 7).

The Attorney General argues that the Department should not depart from the POD method by averaging its results with those from a CP method (Attorney General Reply Brief, p. 1). He points out that the Department previously rejected the use of CP methods for allocating electric generation plant and maintains that the modified peaker POD is a substantial improvement over such methods (id., p. 2). Even if the Department wanted to depart from the traditional POD model, the Attorney General urges the Department to do so prospectively only, for reasons of consistency (id.).

Further, the Attorney General cites several cases where the Department had the opportunity to depart from use of the POD model and consistently preferred the POD method for allocating electric generation costs (id., p. 3, citing Western Massachusetts Electric Company, D.P.U. 84-25, p. 179 (1984); Western Massachusetts Electric Company, D.P.U. 85-270, pp. 257-267 (1986); Western Massachusetts Electric Company, D.P.U. 86-280-A, pp. 135-141 (1987); Western Massachusetts Electric Company, D.P.U. 87-260, pp. 120-137 (1988); Western Massachusetts Electric Company, D.P.U. 88-250, pp. 109-113 (1989); Western Massachusetts Electric Company, D.P.U. 89-255, pp. 96-98 (1990)). In light of this extensive history, the Attorney General recommends that the Department reject the Company's request to propose other alternatives to the POD method in WMECo's next rate case (id.).

iii. The Company Response

The Company asserts that the Attorney General fails to recognize the two basic steps involved in the POD allocation process (Company Brief, p. 10). WMECo claims that its proposed enhancements to the POD have produced a more precise and accurate link between cost causation and cost allocation than had been the case using the prior version of the POD with the PEAKMOD adjustment (id., pp. 11-12). The Company maintains that the Attorney General's arguments to return to the PEAKMOD version are without merit and should be rejected (id., p. 13).

WMECo agrees with Mr. Dwyer's suggestion that the cost of a peaker be based on the equivalent availability of that turbine and not on its nominal capacity (id.).

The Company opposes Mr. Dwyer's categorization of all of the Northfield Mountain facility costs as reliability-related. WMECo claims that Northfield Mountain serves many purposes in addition to reliability and its costs should not be allocated solely to peak hours, but rather to the hours in which it generates power (id., p. 15). According to the Company, Northfield is not modeled in the traditional POD. Instead, both costs and benefits are assigned to hours when Northfield generates power in order to prevent any capacity and energy costs from being borne by customers in the off-peak hours (id., p. 16). The Company claims that Northfield's cost should only be allocated to the hours in which it generates because customers taking power in these hours benefit from the lower energy costs brought about from its operation (id.).

Similarly, the Company opposes the Industrial Intervenor's proposal to modify the POD to reflect a reliability component of NEPOOL purchases. The Company argues that the capacity of NEPOOL purchases is used in the POD model only to determine the reliability costs for NEPOOL purchases. According to the Company, since NEPOOL purchases have no capacity revenue requirements (NEPOOL purchases are not part of rate base), the Company's proposal to eliminate the cost inequality of inputs and outputs makes the reliability costs for NEPOOL purchases zero. Therefore, the Company claims that it is unnecessary to modify NEPOOL purchases as suggested by Mr. Dwyer (id., p. 16).

WMECo also responded to the Industrial Intervenors' observation that some on-peak capacity unit costs for the shoulder months (April-June and September-November) are less than the off-peak capacity unit costs in the same months. According to the Company, this occurs because of the "enhancement" to the POD which allocates reliability-related costs according to contribution to the probability of peak. "Reliability-related" costs of all plants are removed from total costs in all hours and shifted to the peak hours. Consequently, in the shoulder months, when the remaining costs in the on-peak hours are divided by the loads in those hours, the results are lower capacity costs on a per-KW basis than for some on-peak hours (id., pp. 12-14). The Company points out, however, that the aggregate on-peak unit capacity costs are still considerably higher than the off-peak: $65.04 per MW on-peak versus $49.97

per MW off-peak (id.). Thus, the Company argues that the minor anomalies occuring in some on-peak capacity costs in the shoulder months should not call into question its "enhancements" to the POD (id.).

Regarding the arguments of the Industrial Intervenors, WMECo does not recommend adopting any of the Industrial Intervenors' suggestions for the immediate case, but instead urges the Department to accept the Company's proposed "enhancements" to the POD (id., p. 19). However, the Company proposes that the Department allow the Company, in its next base rate application, to explore methods other than the POD and to present recommendations for a production capacity allocation method that would better reflect cost causation on WMECo's generating system (id.).

In its reply, WMECo maintains that its proposed "enhancements" to the POD more properly tie individual production plant capacity costs by period to energy costs for those plants (Company Reply Letter, p. 2).

c. Analysis and Findings

In order to establish the proper allocation of production-related capacity costs, we must determine if the standard by which the Department determines the appropriateness of the allocation method for capacity-related embedded plant costs is met. In Western Massachusetts Electric Company, D.P.U. 86-280-A (1987), we stated that "embedded generating unit costs should be allocated to the class or classes of customers that receive power from those units to meet their demand for electricity." Id., pp. 137-139. In Western Massachusetts Electric Company, D.P.U. 89-255, the Department found that the Company's modified peaker POD model appropriately allocated embedded generating unit costs. Id., p. 97.

The Company proposed its "enhancements" to the POD in response to the Department's directive to explore responses to the fuel symmetry issue raised by the Industrial Intervenors in the last case. However, the changes proposed by the Company would take the allocation calculation so far from the underlying POD method as to call into question whether the resulting method can accurately be styled as a POD approach. Indeed, by segregating baseload costs and so-called "reliability-related" costs from the total capacity costs, and allocating them on an average demand and coincident peak basis respectively, the Company has created an allocator that begins to resemble the average and excess allocation rejected by the Department in favor of the POD approach in 1984. Boston Edison Company, D.P.U. 1720, pp. 121-123 (1984). See also Western Massachusetts Electric Company, D.P.U. 85-270, p. 264; D.P.U. 84-25, p. 179 (1985). The Industrial Intervenors' proposed weighting of the "enhanced POD" results with the results of a coincident peak allocator compounds the tendency of the Company's approach to mimic rejected allocators based on class contribution to a relatively small number of hours in which the units are running.

The Department has for many years required use of the POD for allocation of electric company production capacity costs in lieu of other allocators such as the average and excess allocators. Id. The Department has held that embedded generating unit costs should be allocated to the class or classes of customers that receive power from those units to meet their demand for electricity. Western Massachusetts Electric Company, D.P.U. 89-255, p. 96. The Supreme Judicial Court has upheld the Department's use of the POD method. Monsanto Company v. Department of Public Utilities, 402 Mass. 564, 568 (1988).

In recent years, the Department has allowed limited adjustments to the basic POD. In D.P.U. 87-260, the Department accepted the Company's "modified peaker" version of the POD, in which reliability-related costs of all units were allocated across peak hours, rather than to all hours that the units operate. Id., p. 131. Particular corrections to the allocation of the Northfield pumped storage unit have been approved. D.P.U. 88-250, p. 110. The Department approved the Company's modification to express all capacity costs in current dollars. D.P.U. 87-260 (1988). Other refinements in the modelling process have been approved. Id.

However, the Department rejects the proposals to adopt what amounts to a wholesale departure from the POD method in this docket. Both the Company's "enhancements" and by extension the Industrial Intervenor's modifications to the "enhanced POD" deviate in their basic approach from the underlying theory of the POD. On this record, there is no basis to depart from the precedent of the Department in the allocation of production capacity costs.

However, other than the Company's "enhanced POD" and the Industrial Intervenors' weighting of the Company's "enhanced POD" with a 3 CP allocator, there is no production capacity cost allocator in this record. The Company's calculation in this docket produces results that are likely to be close to the results of the modified peaker accepted in previous cases. Accordingly, it is adopted for the purposes of this case.

Within the framework of the POD, one of the refinements proposed by the Industrial Intervenors in this docket has merit: the use of the equivalent availability factor to adjust the Company's calculated cost of a peaker. The recommendation to identify some portion of Northfield pumping unit costs and NEPOOL purchased capacity costs as reliability-related, however, is rejected. The Department finds that WMECo's practice of modelling Northfield in a manner such that all of its costs and related fuel benefits are assigned to the hours in which the unit is generating power is appropriate. Similarly, the Department finds that the costs associated with the NEPOOL purchases should be allocated to the hours in which the purchases are made. Mr. Dwyer's recommended treatment of Northfield and NEPOOL costs would tend to allocate a disproportionate amount of costs to the peak period, and away from other periods in which the power from the units is also generated or purchased, in contravention of the underlying theory of the POD.

Because the Department does not approve the basis for the "enhanced POD," it is not necessary to address the merits of the Industrial Intervenors' proposal to adjust the "base" and "remaining" costs on a pro rata basis so that the total base, remaining and reliability costs equal the Company's total revenue requirements for the units. In any event, the Company is correct that such changes, if adopted, would produce only a slight change in the resulting allocators (Exh. WM-17, pp. 10-11).

With regard to the question of fuel symmetry, the Department in D.P.U. 89-255 found that a modification to the energy allocator might be appropriate to match the hours in which customers require energy with the cost of fuel expended in each hour to meet that demand. Id. While the Company and the Industrial Intervenors claim that their allocation methods better match capacity and fuel cost allocation, in fact the changes they propose to the POD are not logically related to the fuel symmetry question.

To address the fuel symmetry issue, it is necessary to examine the energy allocator, so that it appropriately matches the capacity allocator. While the Industrial Intervenors and the Company do match their energy allocation approach to their capacity allocation approach, that does not support a finding that their basic allocation approach is correct. If the fuel symmetry question is to be addressed in a theoretically consistent manner, the focus should be on the allocation of fuel costs to the hours in which the plants are producing power. In addition, one should examine whether a redistribution of the fuel costs to hours of plant operation should be accompanied by a redistribution of O&M costs to such hours. In the absence of a superior allocation method on this record, however, the Department accepts the results of the Company's energy allocation for the purposes of this case.

3. <u>Allocation of Transmission-Related Costs</u>

The Company proposes to allocate transmission-related costs based on the "3 CP" allocator. The 3 CP method allocates plant costs based on customers' proportional use of capacity at the time of the Company's three peaks: winter morning, winter evening, and summer. The Company asserts that the 3 CP allocator was calculated in a manner consistent with the method approved by the Department in D.P.U. 87-260 (1988), D.P.U. 88-250 (1989), and D.P.U. 89-255 (1990)(Exh. WM-14, p. 5).

In <u>Commonwealth Electric Company</u>, D.P.U. 88-135/151, pages 145-146 (1989), the Department found that allocating transmission-related costs based on the proportional responsibility ("PR") method was appropriate, since transmission-related costs are incurred in a manner more similar to the way in which production-related costs are incurred.

In previous WMECo cases, the Department allowed the Company to allocate transmission-related costs based on the 3 CP method and did not address the appropriateness of WMECo's method of allocating these costs. In the instant case, no party explored the use of the PR method to allocate transmission-related costs. Therefore, for the purposes of this case, the Department accepts WMECo's allocation of transmission-related costs based on the 3 CP method. However, the Department orders WMECo in its next rate case to file the allocation of transmission-related costs based on the PR allocator.

4. Allocation of Administrative and General Expenses

a. The Company's Proposal

In the Company's last rate case, the Department ordered WMECo to allocate Accounts 923 (Outside Services Employed), 928 (Regulatory Commission Expenses), and 930 (General Advertising and Miscellaneous Expenses) on the basis of a revenue allocator instead of the Company's proposed payroll allocator. Western Massachusetts Electric Company, D.P.U. 89-255, pp. 100-101. The Department directed the Company in future rate proceedings to address whether a revenue allocator would be a more appropriate basis for allocating other administrative and general overhead expenses (specifically, Accounts 920, 921, 931, and 935) in the Company's cost of service study (id., p. 102). In the instant proceeding, WMECo allocated Accounts 923, 928, and 930 based on revenues in accordance with the Department

Order but did not allocate any additional accounts based on revenues (Exh. WM-14, pp. 8-9).

The Company continued to allocate Accounts 920 (Administrative and General Salaries), and 921 (Office Supplies and Expenses) on the basis of payroll. The Company allocated Accounts 931 (Rents), and 935 (Maintenance of General Plant) based on a plant allocator (id., p. 9).

b. Positions of the Parties

i. The Attorney General

The Attorney General maintains that the Company does not demonstrate how payroll or plant is superior to revenues as an allocator for Accounts 920, 921, 931, and 935, or why the Company's previously-rejected method should replace the Department's method of allocating these predominantly general overhead expenses (Attorney General Brief, p. 9). According to the Attorney General, the expenses in Accounts 920, 921, 931, and 935 are overhead in nature and should be allocated based on revenues (Attorney General Reply Brief, p. 10).

He states that Account 920 includes compensation for officers and other employees not chargeable to a particular operating function (Attorney General Brief, p. 9, citing Exh. AG-139, p. F14-1). He argues that since these expenses are not related to any operating function or customer group, they should be allocated by a broad allocator such as revenue rather than payroll (id., p. 9).

He also asserts that Account 921 includes expenses of employees appearing before regulatory agencies, trade association dues and legal expenses, similar in nature to the expenses in Accounts 923, 928 and 930, and therefore should be allocated on the basis of revenues (id., pp. 9-10).

Account 931 includes expenses for office and office equipment rentals. The bulk of these account expenses, according to the Attorney General, are contained in Subaccounts .01 and .99, which specifically refer to the administrative and general ("A&G") function and should be allocated based on a revenue allocator (id., p. 10).

Finally, Account 935 includes maintenance of certain structures, office furniture, communications and miscellaneous equipment. The Attorney General asserts that the bulk of these expenses are contained in Subaccount .01, which includes, among other items, maintenance of rented structures for A&G functions. Therefore, he argues that a revenue allocator is more appropriate than the Company's plant allocator (id.)

The Industrial Intervenors did not address this issue.

ii. The Company

In its brief, the Company points out that the Department ordered WMECo in D.P.U. 89-255 to allocate Accounts 923 and 930 on the basis of a revenue allocator and to address in its next proceeding whether a revenue allocator would be a more appropriate basis for allocating other general overhead expenses (Company Brief, pp. 21-22). In this case, the Company continues to support the allocation of general overhead expenses on the basis of a payroll rather than a revenue allocator (id., p. 22, citing Exh. WM-14, p. 9). Although the Company maintains its support for its proposed methods of allocating general overhead expenses, for purposes of this proceeding the Company accepts the Attorney General's recommendation to allocate accounts 920, 921, 931, and 935 on the basis of revenue rather than payroll (id., p. 22).

c. Analysis and Findings

The Attorney General is correct that the Department has required either an energy or revenue allocator for A&G costs relating to general overhead. See Western Massachusetts Electric Company, D.P.U. 89-255, pp. 99-102 (1990); Western Massachusetts Company, D.P.U. 88-250, pp. 116-117 (1989); Cambridge Electric Light Company, D.P.U. 89-109, pp. 33-34 (1989); Eastern Edison Company, D.P.U. 88-100, p. 42 (1988). In D.P.U. 89-255, pages 100-101, we held that where costs are related to general overhead expenses rather than specifically to labor, class revenue is the most appropriate allocator because general overhead expenses are a function of the size of a utility's expenses and revenues rather than the energy or labor expense incurred to serve a specific class.

More recently, the Department found that an appropriate refinement of the revenue allocator would be a class revenue requirement allocator. Colonial Gas Company, D.P.U. 90-90, p. 16 (1990). In that Order, we stated:

> With the objective of a fair and equitable distribution to rate classes of general A&G expenses, the Department finds that a refinement of the revenue allocator would be a class revenue requirement allocator. This allocator would be developed as a summation of total cost of service and would also include those A&G expenses assigned as a specific allocator, e.g., plant, labor, etc. A revenue requirement allocator is similar in concept to the revenue allocator and would provide a reasonable basis to assign general expenses to each rate class without suffering from the deficiencies regarding a revenue allocator cited by the Company.

This finding was upheld in Fitchburg Gas and Electric Light Company, D.P.U. 90-122, pages 22-23 (1990). Since general overhead expenses are not dedicated to serve any particular customer group directly, but are dedicated to serve the Company's customers as a whole, it makes little sense to attempt to establish a direct cause/effect link between cost incurrence and the expenses or consumption patterns associated with any individual customer class. In this situation, it is more important to develop a fair sharing of these costs between customer groups. Therefore, it is appropriate to allocate general overhead expenses to customer classes proportionally based on class revenue requirements rather than to rely on a narrower allocator such as plant or payroll. Accordingly, the Department orders the Company to allocate Accounts 920, 921, 923, 928, 930, 931, and 935 based on a class revenue requirements allocator.

5. Allocation of Conservation and Load Management Expenses

Three methods have been proposed in this proceeding for the allocation of costs incurred by the Company in implementing its C&LM programs. The Company proposes that all C&LM costs be allocated in the same manner as generating resources, using POD allocators. The Attorney General proposes that all C&LM costs be allocated directly to the rate classes eligible for enrollment in each program. Finally, the Industrial Intervenors recommend that C&LM expenses not be included in base rates at all, but rather should be collected through a conservation charge only from those that participate in a program.

Over the course of the past year, the Company's allocation method has been to assign C&LM expenses to generic customer classes (i.e., residential, commercial, industrial, street lighting) based on the expenses incurred for each customer class. Within customer classes, C&LM expenses were further allocated to each rate class on the basis of POD allocators. The Company's allocation was thus a hybrid between the pure POD method proposed this year and the direct assignment method which is Department precedent.

a. Positions of the Parties

i. The Company

The Company states that historically it has allocated all C&LM costs directly to the classes of customers whose loads are to be affected by the C&LM programs. The Company argues that this method was appropriate because the benefits of these programs were anticipated to accrue almost entirely to the customers eligible for the programs and because the programs were not linked to long-term system planning objectives. Because the C&LM programs are now designed to achieve substantial reductions in the need for new generating capacity in the mid-1990's, the Company argues that the substantially expanded C&LM budgets should be allocated in the same manner as the generating resources they defer (Company Brief, pp. 19, 20).

The Company states that it does not support the cost recovery mechanism proposed by the Industrial Intervenors because it disregards the Department's well-established policies for C&LM cost recovery and the extensive work of the Company and the non-utility parties to design C&LM programs and cost recovery methods (id., pp. 20, 21).

Finally, the Company acknowledges that there is merit to the traditional allocation of C&LM expenses directly to rate classes, and although it prefers its proposed methodology, it would not object to the direct allocation advocated by the Attorney General (id.).

ii. The Attorney General

The Attorney General states that both the Company's proposal and that of the Industrial Intervenors assume that all rate classes benefit equally from the Company's C&LM programs, an assumption that the Attorney General asserts is clearly not the case at this time (Attorney General Brief, p. 11). According to the Attorney General, the Company's proposed POD allocation methodology would burden residential customers with more than $1 million of additional C&LM costs above what they would pay under a direct allocation. The Attorney General maintains that direct allocation is the fairest method, since it assigns C&LM costs directly to the classes which benefit directly from the programs, and urges the Department to adopt this method (id.).

iii. The Industrial Intervenors

In accordance with the cost-recovery proposal presented by their witness, Mr. Rosenberg, the Industrial Intervenors state that all C&LM costs should be excluded from the cost of service allocation process (Industrial Intervenors Brief, p. 13). The Industrial Intervenors request that the Department pursue four objectives in evaluating C&LM programs:

(1) to match, as nearly as possible, allocation with cost-causation;

(2) to put Company-supplied C&LM measures on a level playing field with both supply-side measures and non-utility supplied C&LM measures;

(3) to minimize free-riders as much as possible; and

(4) to minimize adverse effects on non-participants.

(id., p. 28).

The Industrial Intervenors claim that these objectives are consistent with Department objectives and goals, but that they are not accomplished under the Company's historical method of direct assignment (id.).

According to the Industrial Intervenors, direct assignment to rate classes is unfair, because although both commercial and industrial customers may be in the same rate class, they do not have equal access to Company-provided C&LM services. The Industrial Intervenors claim that this is because C&LM programs have been designed to address specific end-uses rather than rate classes, and since commercial end-uses are more homogenous than those found in industrial processes, the Industrial Intervenors assert that programs targeting commercial end-uses are much more extensive than those designed for the industrial sector (id.).

The Industrial Intervenors claim that both the current and the proposed allocation methods presented by the Company fail to minimize effects on non-participants, minimize free-riders, or place the Company's C&LM programs on a level playing field with supply or non-utility C&LM measures (id., p. 29). In place of these allocation methods, the Industrial Intervenors favor the following approach:

> (1) All C&LM costs would be explicitly excluded from the base revenue targets and from the cost-of-service study.
>
> (2) Base rates would be set in the usual way based on the test year billing determinants.
>
> (3) The Department would authorize an amount of conservation dollars to be recovered by WMECO. These dollars would be used to set unit conservation rates. These rates could vary by program or by rate class, or then could be calculated as a uniform rate for all customers.
>
> (4) Participants in the C&LM programs would be billed the normal base rates on the metered units. In addition, they would pay the unit conservation rate on the saved (or "substituted") units.

(id.).

The Industrial Intervenors claim that this proposal is in accordance with the Department's preference for direct assignment, in that individual participants are assigned C&LM costs in the exact amount of their participation (id., p. 30). Furthermore, the Industrial Intervenors assert that the proposal would achieve the four objectives outlined above (id.). Accordingly, the Industrial Intervenors urge the Department to adopt their proposed cost-recovery mechanism.

b. Analysis and Findings

As an initial matter, the Department finds that the Industrial Intervenors' C&LM cost-recovery proposal is inextricably linked with the amortization or inclusion in rate base of Company C&LM expenditures, issues which are addressed in the Company's C&LM preapproval case, D.P.U. 91-44, Sec. IV. The issue to be addressed here is the fair and equitable allocation of costs incurred by the Company in implementing its C&LM programs, programs which provide benefits both within and outside of the specific rate classes in which money is spent.

The Department did not require the Company to adopt a specific allocation methodology for C&LM expenses in either its last rate case or C&LM preapproval Orders. Wherever C&LM costs have been included in base rates in the past, however, the Department has consistently opted for direct allocation of C&LM costs to rate classes, as advocated by the Attorney General in this case.

In Western Massachusetts Electric Company, D.P.U. 88-250 (1989), the Department accepted the Company's proposed direct allocation of C&LM expenditures to the rate classes eligible for each C&LM program. In that case, the Department found that general C&LM expenses not directly assignable to a particular program should be allocated on the basis of an energy allocator, although it recognized that such expenses could arguably be allocated using POD or general overhead allocators, or could be apportioned among the C&LM programs. The Department ordered the Company to address the allocation of general C&LM expenses in its next rate proceeding.

In Massachusetts Electric Company, D.P.U. 89-21 (1989), the Department noted that it had historically treated pilot C&LM programs as providing indirect benefits to all consumers, and thus had previously allocated the costs of such programs using a customer allocator. In that case, the Attorney General argued successfully that this method overallocated C&LM expenses to the residential ratepayers, and that a direct allocation would be more fair. The Department found that "where there is clear evidence that the costs attributable to a program are providing benefits to a particular rate class, direct assignment is preferable." Id., p. 21. Accordingly, the Department ordered the Company to directly allocate C&LM expenses.

The next case in which the Department addressed the issue of C&LM cost allocation was Cambridge Electric Light Company, D.P.U. 89-109 (1990). In this case, the Department recognized that C&LM programs provided benefits available only to participants as well as benefits that accrued to all ratepayers:

> The energy and capacity savings to the electric company's system will accrue to all customers in the same way as supply-side resources. However, with C&LM there are also direct benefits to the participating customers in the form of reduced bills. These additional benefits distinguish demand-side from supply-side resources and possibly suggest a different cost allocation method.

Id., p. 45.

In D.P.U. 89-109, the Department recognized that it could be theoretically appropriate to allocate C&LM costs to reflect system-wide benefits via energy and capacity allocators, or to allocate such costs directly to participating classes, since these classes receive the additional benefits of lower bills. Alternatively, the Department noted that some combination of these allocators could be used. The Department found that the record in that case did not establish any of the possible approaches as theoretically more appropriate than the others, but opted for a direct allocation in order to minimize the potential for adverse rate impacts on classes with high levels of non-participants.

The most recent case in which the C&LM cost allocation issue was raised is <u>Massachusetts Electric Company</u>, D.P.U. 89-194/195 (1990). In that case, the Company and the Energy Consortium argued that as with supply resources, C&LM cost allocation should reflect cost causation. They maintained that C&LM costs should therefore be functionalized and allocated based on the same allocators used for capacity, energy, and distribution as the supply-side resources they are designed to avoid. The Attorney General countered that the majority of benefits resulting from C&LM programs accrued to the participants through reduced electric bills, and therefore that the classes to which the participants belong should bear the costs for the program. In its Order, the Department framed the issue in this way:

> The Department's major concern in cost allocation is fairness. Fairness requires that cost allocation be designed to reflect the Company's costs to serve each rate class, directly assigning those costs associated with providing services to a class and allocating joint and common costs when direct assignment is impossible.

Id., p. 211.

The Department determined in D.P.U. 89-194/195 that although only a limited number of customers within each class could participate in the programs targeted at that class, customers were prohibited entirely from participating in programs targeted at other classes. The Department found it inappropriate that customers prohibited from participating in a program because their class had not been offered that program should experience an increase in their bills to pay for it. Accordingly, the Department reaffirmed precedent and allocated costs directly to those classes for which the costs are incurred. Id., p. 212. The Department noted, however, that in future cases it would review the distribution of program costs and benefits to determine the most equitable allocation of program costs.

In the current case, the Company presents an argument similar to that used by Massachusetts Electric in D.P.U. 89-194/195. The Company maintains that since its C&LM programs provide system-wide capacity benefits, the costs of those programs should be shared among the rate classes in the same way that the costs of generating units are shared. The Department finds a degree of merit to this argument -- certainly there are benefits to all ratepayers which extend beyond those available only to participants in a C&LM program. However, the Department finds that the Company's proposal to allocate all C&LM expenditures on the basis of its POD allocators is inappropriate in two respects.

First, the Company's proposed allocation methodology ignores entirely the benefits accruing to participants through reduced electricity bills. Yet the record in this case demonstrates that the energy benefits enjoyed by participants greatly outweigh the capacity reductions which benefit the system as a whole (RR DPU-009). As noted supra, the Department found in Cambridge Electric Light Company, D.P.U. 89-109 (1989), that because C&LM expenditures in a given class provide benefits available only to program participants in that class (in addition to the system-wide benefits), it was appropriate to allocate those expenditures in a manner distinct from that used for generating resources (for which such benefit segregation does not occur).

Second, even if it could be shown that the only benefits of the C&LM programs were system-wide benefits enjoyed by all ratepayers, the Company has provided no evidence that the allocators used to apportion the costs of generating units accurately reflect the distribution of system-wide benefits due to C&LM programs. Unless the C&LM programs were included as quasi-generating units in the calculation of the POD allocators, it would be coincidental indeed if the programs' contribution to meeting system load followed the same pattern as that implied by the allocators. Because this approach has not been followed in this case, the Department cannot accept the Company's proposed allocation methodology.

The Department finds that a direct allocation of C&LM costs to the classes in which expenditures are made will match C&LM benefits and costs more equitably than an allocation based solely on POD. The record indicates, however, that the Company is not currently capable of implementing direct allocation because it has not, to date, collected information on the rate class of the participants in its C&LM programs (Exh. AG-94, Supplement 2). The Company states that it is addressing the necessary accounting methods that will enable it to perform such an allocation in the future, but that even with these methods in place, a period of time on the order of one to two years would be required to accumulate sufficient data to enable a reasonable cost allocation (id.).

Given that the data necessary to implement a direct allocation do not exist at this time, the Department cannot order the Company to perform such allocation. Instead, the Department orders the Company to continue to employ the hybrid methodology it has used in the past (i.e., direct allocation to the generic customer classes followed by POD allocation to each rate class). The application of this methodology to the C&LM budget approved today in D.P.U. 91-44 is illustrated by Exhibit AG-94, supplement 1. In addition, the Department orders the Company to modify the tracking system for each of its C&LM programs as necessary, and to immediately begin collecting rate class information for every participant in its programs, so that the Company will be able to implement direct allocation in the future, should it be ordered to do so by the Department.

The Department recognizes that compelling arguments can be, and have been made in support of alternate C&LM allocation methodologies. In this case, the Company recommended that the allocation methodology be changed to more accurately reflect the distribution of benefits provided by C&LM. Similarly, one of the motivations behind the Industrial Intervenors' cost-recovery proposal is to better match costs with benefits. In rejecting the Company's and the Industrial Intervenors' proposals, the Department does not imply that the allocation ordered today exactly matches cost allocation with the distribution of benefits. As the Industrial Intervenors point out, because C&LM programs are designed to address end-uses rather than rate classes, the direct allocation of C&LM expenses creates some inequity, particularly with respect to non-participants in the C&I classes. The Department's requirement that companies spread the benefits of C&LM as broadly as possible and its directives to bring companies into compliance with that goal can only partially address this inequity.

Although the record in this case does not support the adoption of either the Company's or the Industrial Intervenors' proposal at this time, the Department recognizes that the allocation of C&LM expenses is an ongoing issue which will evolve with time. The Department notes that many of the allocation and equity issues considered in this case are being reviewed in the context of D.P.U. 91-80, currently before the Department, and encourages interested parties to participate in that process.

6. <u>Classification of Distribution Plant</u>

a. <u>The Company's Proposal</u>

Distribution plant consists of both demand- and customer-related plant. According to WMECo, the demand portion recognizes investment to meet load requirements. The Company proposes to allocate these costs on the basis of the maximum noncoincident demand at the distribution substation level (Exh. WM-14, p. 5). The customer portion recognizes costs that vary with the number of customers and are incurred regardless of load requirements. Customer-related items have been limited to customer service drop costs (Account 369) and meter costs (Account 370), as well as to items which can be directly assigned to specific classes of customers, including street lighting, and large general service (<u>id</u>.). Although the Company does not agree with the Department that the classification of customer-related items should be limited to the service drop, meters, and other costs that can be directly assigned to customers, WMECo stated that it followed the Department's standard (<u>id</u>., p. 6). In addition, appropriate accounts in the distribution category have been separated into primary and secondary components (<u>id</u>.).

b. Positions of the Parties

i. The Industrial Intervenors

The Industrial Intervenors recommend that the Department revisit issues relating to the customer component of distribution plant (Industrial Intervenors Brief, p. 10). In his testimony, Mr. Rosenberg stated:

> Separate and apart from the incremental load attributable to the new customers, attaching customers to the new system requires additional investment in poles and conductors. Simply put, it costs more to attach and serve 1,000 customers each with a peak demand of 10 KW than it does to attach and serve one customer with a peak demand of 10,000 KW, even though the demands are the same.

(id., pp. 10-11, citing Exh. II-2, pp. 17-18).

In their brief, the Industrial Intervenors rely on the information submitted by the Company in Record Request II-9, which are the results of analyses conducted for CL&P. The analyses determined a customer component of distribution plant for Accounts 364, 365, 366, 367, and 368. The Industrial Intervenors point out that the Connecticut Department of Public Utility Control ("Connecticut") recognizes this customer component in determining cost of service. Mr. Rosenberg used the same customer component as approved by Connecticut. He supports the minimum-size method for determining the customer component of distribution plant.[3] Mr. Rosenberg advocates

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3 The minimum size methodology develops the customer cost by adding to the costs of maintaining customer accounts the cost of a theoretical minimum distribution system, and its corresponding operation and maintenance expenses. The difference between theoretical minimum distribution system costs and total costs is then classified as a demand-related cost. Western Massachusetts Electric Company, D.P.U. 20110-A, p. 12 (1982).

using the same factors for WMECo as those listed in Record Request II-9.

ii. The Attorney General

The Attorney General did not address this issue in his initial brief. However, in his reply brief, he asserts that the Department should not assign a portion of distribution costs as customer-related, especially where such an assignment is based on borrowed data and a miminum-size method (Attorney General Reply Brief, p. 6). The Attorney General cites a previous Department Order where the Department found:

> Allocating costs of the distribution system other than service drops to the customer charge is a questionable practice. As previously indicated, the customer charge should reflect costs which vary with the number of customers on the system....It can hardly be persuasively argued that distribution costs will decrease with the loss of a single customer or increase with the addition of one. Also, practical considerations weigh against a definition of customer costs which includes a substantial portion of the distribution system....In the future we will require that the Company include only service drop and meter costs along with customer accounts expenses in the customer costs.

(id., quoting from Western Massachusetts Electric Company, D.P.U. 20110-A, pp. 13-14 (1982)).

First, the Attorney General asserts that the premise underlying the allocation proposed by WMECo and the Industrial Intervenors is incorrect. The additional plant costs beyond the service drop, according to the Attorney General, do not vary directly or significantly with the number of customers. Instead, he claims the plant costs depend upon load, geography and customer density at least as much as upon customer number

(Attorney General Reply Brief, p. 7). Second, the Attorney General asserts that it is not even clear that there is a "minimum distribution system" or that the costs are determinable (id., pp. 7-8). Third, the Attorney General argues that the proposed allocation would lead to double-counting since plant costs are already allocated based on the total load per customer class. An allocation of the proposed distribution plant based on customer number would mean that customers would be paying for this plant twice, as an individual customer and then as a contributor to load (id., p. 8). Further, the Attorney General asserts that the impact of this double-counting would fall disproportionately upon lower-use customers. Because lower-use customers generally tend to live closer together and be served by less costly distribution plant, the Attorney General argues that it would be unfair to allocate a disproportionately large share of these costs to them (id.). Finally, the Attorney General claims that the proposed reallocation should be rejected because it is based on "borrowed" data from Connecticut (id.).

He points out that the Department has previously found that load data used for cost of service studies must be specific to the service territory, not borrowed from another service territory or company and that neither the Company nor the Intervenors have supplied any reason for an exception here (id., pp. 8-9).

The Attorney General urges the Department to reaffirm its precedent and reject the reallocation of distribution plant based on customer-related costs above and beyond meters, service drops and directly assigned items (id., p. 9).

iii. The Company

The Company claims that the current classification of distribution plant understates WMECo's costs for the customer component (Company Brief, p. 23). Therefore, the Company urges the Department to determine that costs for a customer component included in Accounts 364 through 368 are appropriate for purposes of this proceeding. The Company recommends using the minimum-size method results included in Record Request II-09 (id., p. 24). As an alternative, the Company requests that it be allowed to include a customer component for Accounts 364 through 368 in its cost of service study in its next rate application (id.).

The Company states in its reply letter that the Attorney General's argument that distribution plant costs depend on load, geography and customer density further acknowledges that a significant portion of distribution plant costs indeed vary with customer number. Moreover, some portion of costs in Accounts 364 through 368 are incurred in proportion to the number of customers and location, not load (Company Reply Letter, p. 2). Further, according to WMECo, the Attorney General's assertion that there is double-counting is incorrect because costs in each of the affected accounts are separated into a demand portion and a customer portion; the demand portion would be allocated based on load and the customer portion would be allocated based on the number of customers served (id.). Finally, the Company points to the Attorney General's objection to using CL&P's cost data because of the Department's prior rejection of another company's use of borrowed load data. WMECo claims that since CL&P's data is not a load data study, the Attorney General's argument should be rejected (id., p. 3). If the CL&P study is rejected, the Company asks that it be permitted to identify a customer component of distribution costs in its next filing (Company Brief, p. 24).

c. Analysis and Findings

During the proceeding, Mr. Berthold testified that it is customary to identify customer-related costs in Accounts 364 through 368, and to then allocate those customer costs on the basis of the number of customers to the various rate classes (Tr. VIII, pp. 43-44). The method involves splitting the costs in Accounts 364 through 368 into a demand and customer component, and then allocating the demand component on a demand allocator and the customer component on a customer allocator (id.). The split generally involves the use of one of two methodologies: minimum size or minimum-intercept to identify the customer component. Connecticut has granted the use of the minimum-size method (RR II-09).

As cited above, the Department found in D.P.U. 20110-A that it is appropriate to assign customer-related costs only to service drop and meter accounts. The Department finds no reason to deviate from that precedent. Thus, it is unnecessary to address the question of whether the CL&P cost data are sufficiently comparable to cost patterns for WMECo to make use of the CL&P study an adequate basis for the identification of a customer component of distribution charges.

Accordingly, the Department orders the Company to continue the limitation of customer-related distribution costs to customer service drop and meter accounts.

C. Class Revenue Requirements

1. The Strathmore Contracts

Two facilities of the Strathmore Paper Company, the Turners Falls and Woronoco facilities, take power from WMECo under a special contract rate ("the Strathmore contracts" or "Strathmore"). Each of these facilities was treated as a separate entity in the cost of service study for the purposes of determining that customer's individual revenue requirement (Exh. WM-10, p. 14). The Company originally proposed a 27.2 percent increase in the revenue requirement for these contracts (Exh. II-2, Sch. 3).

a. Positions of the Parties

i. The Industrial Intervenors

The Industrial Intervenors challenge the proposed 27.2 percent increase in the Strathmore contracts rate, claiming that the increase for Strathmore should not exceed the system average increase of 17.8 percent (Industrial Intervenors Brief, p. 11). On this point, the Industrial Intervenors assert that the Strathmore contracts were brought to cost in the Company's last rate case (*id*., p. 11).

The Industrial Intervenors also assert that the proposed increase is disproportionately high and that rates for the Strathmore contracts may be distorted in two ways. First, the Industrial Intervenors point out that the Turners Falls facility has an exchange agreement allowing it to generate with the same water Strathmore would use, at times when requested by WMECo. Consequently, according to the Industrial Intervenors, the metered usage at the Turners Falls facility is not only a function of the facility's requirements, but of WMECo's requests (Exh. II-2, p. 15). Second, the Industrial Intervenors argue that the Company's use of the "enhanced" POD allocator and its failure to use weather-normalized load data to design rates make the allocation to the Strathmore contracts rate unreliable and could result in distorted rates (Industrial Intervenors Reply Brief, p. 4).

The Industrial Intervenors also argue that there has been a reduction in sales and peak loads for the Turners Falls facility from the test year in the last rate case to the test year in this rate case (Industrial Intervenors Brief, p. 12).

Citing the above factors, the Industrial Intervenors assert that the Strathmore contracts should receive a lower-than-system average increase (Industrial Intervenors Reply Brief, p. 4). The Industrial Intervenors argue that the Strathmore contracts should be treated as a single group with the T-2 class, which is a large, general, primary service, time-of-use rate, and given the same base rate increase of 16.9 percent (Exh. II-2, p. 14). The Industrial Intervenors maintain that absent the existence of the special contracts, Strathmore would be included with the T-2 class (id.).

ii. The Company

WMECo argues that the POD accurately reflects the increases in the contract customers' loads, so there is no flaw in the cost of service for the Strathmore contracts (Company Reply Letter, p. 3).

The Company also disputes the Industrial Intervenors' claim that the metered usage at the Strathmore Turners Falls facility may be distorted because of an existing water exchange agreement. The Company claims that the energy used in the cost of service analysis is net of any KWH attributable to the exchange for water and that all aspects of the agreement have been properly accounted for in the Company's cost of service study (id., p. 5).

With regard to the Industrial Intervenors' recommendation to treat the Strathmore contracts and Rate T-2 as a single group with the same rate increase, the Company maintains that it has complied with the Department's finding in a previous rate case to set individual rates for each special contract customer and that this proposal is inappropriate and inconsistent with precedent. Exh. WM-17, citing Western Massachusetts Electric Company, D.P.U. 86-280-A, pp. 214-215 (1987). WMECo argues that its Strathmore rates have been designed in accordance with this past Order and that the special contract customers should not be allowed to switch rates from year to year, depending on which produces the most favorable results in any particular year (Exh. WM-17, p. 5).

b. Analysis and Findings

The record in this case demonstrates that there is a basis for the Company's proposed increase in the Strathmore contracts rate. First, the two facilities on this rate experienced an overall increase in consumption. While the Turners Falls facility did decrease its KWH consumption from the last rate case test year to the present test year, the facility's KW consumption increased (Exh. WM-17, p. 4). The Woronoco facility increased both its KWH and KW consumption over the two years (id.). The Company stated that this increase occurred mainly because Strathmore reduced its self-generation and began purchasing those requirements from WMECo (id.). The Industrial Intervenors' assertion that the metered usage at the Turners Falls facility may be distorted because of an existing water exchange agreement is incorrect; the increases are net of any KWH attributable to the water exchange agreements with WMECo (id., p. 5).

In addition, the overall increase in rates due to the Company's revenue request and the resulting Settlement in this case is lower than the increases referenced by the Industrial Intervenors. Therefore, the percentage increases cited by the Industrial Intervenors for both the system and for Strathmore are overstated. The increase for Strathmore is within a reasonable range of this overall increase in rates.

We also take this opportunity to reaffirm our holding in D.P.U. 86-280-A, page 215, in which we held that individual rates should be set for special contract customers. While the contract is in existence, these rates are not subject to change simply on the basis that some other rate is more favorable; this would encourage rate shopping. In the course of a rate case, the Department will of course review any proposed increase to determine if it is reasonable based on the evidence.

D. Marginal Cost Study

The Company developed estimates of its marginal capacity cost and marginal energy cost, in order to form the basis for a marginal-cost-based rate design (Exh. WM-10).

1. Capacity-Related Marginal Costs

The Company proposed that marginal production capacity costs be based on the modified peaker method. Using this method, an 84.3 MW peaker was assumed to come on line in the year 2001 at a present-value annual levelized cost of $59.29 per KW per year (Exh. WM-13, Table A-6; Tr. VII, p. 12).

Using NU's construction budget program and projections of future load growth, the Company proposed to estimate marginal transmission costs by taking five years of future investment necessary to serve additional load divided by five years of additional load growth. Future dollars were discounted back to 1991 and a carrying charge rate was applied to annualize investment costs (Exh. WM-10, p. B-7).

Neither the Attorney General nor the Industrial Intervenors commented on this issue.

The Department finds the Company's proposed production andtransmission capacity-related marginal costs consistent with WMECo's last rate case order, D.P.U. 89-255. Accordingly, the Department finds the Company's marginal production and transmission capacity costs acceptable as proposed by the Company.

The Company proposed to calculate marginal distribution capacity costs using the same method it used for the marginal transmission capacity costs (id., p. B-8). Marginal distribution costs were calculated for both primary and secondary voltage levels (id., pp. B-8, B-9).

The Attorney General did not comment on the Company's proposed capacity-related marginal costs. The Industrial Intervenors commented on the Company's marginal distribution capacity cost study discussed infra, Section IV.E.2.c.viii., in regard to the Partial Requirements Rate.

2. Energy-Related Marginal Costs

a. The Company's Proposal

The Company calculated marginal energy costs at the busbar by using the Polaris production cost simulation model, which simulated dispatch of NU generating units (Exh. WM-10, p. B-6;

Tr. VII, p. 11).[4] The model was run for every hour of the first year the new rates will be in effect. First, using the model the Company increased the anticipated load for every hour by 50 MW and compared that production cost (i.e., the cost of fuel and O&M) to the production cost at the anticipated load. The Company took the difference in the production cost of the anticipated load and the load increased by 50 MW and divided by the total megawatt-hour change to get an average 50 MW increment cost (Tr. VII, p. 28).

Next, the Company determined an average 50 MW decrement cost by repeating the above steps using a 50 MW decrement in the anticipated load instead of a 50 MW increment. Lastly, the Company averaged the two together to get the marginal energy cost (id.).

The model was run using the above steps for hours defined as peak hours to determine peak marginal energy costs, and hours defined as off-peak to determine off-peak marginal energy costs. Line loss factors for each time period and voltage level were applied to derive marginal energy costs at the meter (Exh. WM-13, p. 7).

b. Positions of the Parties

The Industrial Intervenors argue that several changes need

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4 The Polaris production cost simulation model is a supply planning tool for electric utilities that simulates the operation of the utilities' generation.

to be made to the Company's marginal energy cost. First, the Industrial Intervenors claim that the Company's marginal energy cost relies on outdated fuel price data. According to the Industrial Intervenors, fuel prices have fallen from $31.00 to $15.00 per barrel since the Company prepared its rate case. Accordingly, in Record Request II-7 the Company recalculated marginal energy cost based on the most current oil price forecast. The Industrial Intervenors argue that the marginal energy costs should be based on the information in Record Request II-7 (Industrial Intervenors Brief, p. 20).

Second, the Industrial Intervenors state that the fuel charge factor that the Company subtracted from the marginal energy costs to obtain the base energy charges in its initial filing were not derived from equivalent fossil fuel costs. The Industrial Intervenors claim that the fuel charge factor used by the Company is not correct. Accordingly, in Record Request II-12 the Company derived the fuel charge factor utilizing the same fossil fuel costs as utilized in the most current derivation of marginal energy costs, which are presented in Record Request II-7. The Industrial Intervenors argue that the marginal energy costs should be adjusted using the information provided in Record Request II-12 (Industrial Intervenors Brief, pp. 20-21).

Lastly, the Industrial Intervenors argue that the FCRA charges should be removed from the energy charge to arrive at the proper marginal energy cost (Industrial Intervenors Brief, p. 21).

The Attorney General did not address this issue.

In response to the Industrial Intervenors' arguments described above, the Company states that it agrees with the Industrial Intervenors that the marginal energy charges should be set using the most current marginal energy cost information in the record, which is contained in Record Request II-7 and Record Request II-12 (Company Reply Letter, p. 4).

c. Analysis and Findings

The Department has found that marginal energy costs should be based on the most recent available fuel price forecast. Fitchburg Gas and Electric Light Company, D.P.U. 90-122, p. 44 (1990). Accordingly, the Department adopts the proposal of the Industrial Intervenors to derive base marginal energy costs using current fuel price projections, both in the derivation of marginal costs and in the derivation of fuel charge costs that are netted against the marginal costs to determine base energy costs.

Therefore, the Department finds that the following adjustments to the Company's marginal energy costs shall be incorporated into the calculation of marginal energy cost of each rate class:

(1) The Company shall use the most recent oil price forecast provided in Record Request II-7.

(2) The fuel charge factor that the Company uses to determine marginal base energy charges shall be that provided in Record Request II-12.

(3) The FCRA charges shall be deducted from the marginal base energy charges to arrive at the proper marginal energy costs.

E. Rate Design

1. Introduction

WMECo recommended equalizing rates of return for all rate classes (Exh. WM-8, p. 3). However, with regard to marginal costs, the rate designs proposed by the Company vary from rates based strictly on marginal costs because of continuity constraints (id.).

2. Rate-by-Rate Analysis

a. Residential Rates R-1, R-3, R-4, and R-5

Residential Rate R-1 applies to the regular domestic use of electricity, and Rate R-3 applies to the use of electricity by customers who use electric energy as their primary space heating source (Tr. IV, p. 57). Rates R-4 and R-5 are the Company's optional time of use ("TOU") rates for R-1 and R-3 respectively (Exh. WM-10, p. 8).

The Company proposed consolidating rates R-1 and R-3 into a new rate called R-0 and proposed R-2 as its optional TOU rate (id.).

In Table 1 below are WMECo's existing and proposed charges for its residential rates.

Table 1

	Existing Charges			Proposed Charges		
Rate	Customer	Energy (¢/KWH)		Customer	Energy (¢/KWH)	
		Peak	Off-Peak		Peak	Off-Peak
R-1	$9.00	8.050	8.050	$11.00	9.380	9.380
R-3	$10.50	8.601	8.601	$14.00	10.825	10.825
R-4	$13.00	10.562	5.158	$15.00	12.000	6.394
R-5	$14.50	11.672	5.543	$18.00	14.483	7.226
R-0	N/A	N/A	N/A	$12.00	9.780	9.780
R-2	N/A	N/A	N/A	$16.00	12.729	6.607

No intervenor commented on the Company's residential rate design.

In the Company's last rate case, the Department rejected the consolidation of rates R-1 and R-3 because of the potential for rate discontinuities and rate subsidy within classes. Western Massachusetts Electric Company, D.P.U. 89-255, p. 123 (1990). However, WMECo maintains that such consolidation would produce a more equitable rate than presently exists (Company Brief, p. 30).

No evidence was presented in this docket that would persuade the Department to reverse its decision in D.P.U. 89-255 to maintain separate R-1 and R-3 rate classes. Accordingly, the Department directs the Company to maintain separate R-1 and R-3 rate classes and to calculate R-1 and R-3 rates separately using each class' respective revenue requirement allocations and billing statistics.

The Department finds that the Company's proposed residential rates differ more than necessary from marginal costs and are not justified by continuity constraints. Therefore, on the basis of continuity, the Department directs the Company to set the customer charges at $9.50, $11.50, $13.50, and $15.50 for rates R-1, R-3, R-4, and R-5 respectively, and to set the energy charges to collect the remaining base revenue requirement allocated to each class.

b. Low-Income Discount

i. Positions of the Parties

Initially, the Company proposed no changes to its low-income discount. Presently, the low-income discount is offered to recipients of Supplemental Security Income ("SSI"), Aid to Families with Dependent Children ("AFDC"), General Relief ("GR"), Food Stamps, and Veterants Service Benefits who are customers on Rates R-1, R-3, R-4, or R-5 (Exh. WM-11, p. 37). Customers with this discount receive a 35 percent reduction to their base electrical bill.

Based on the Partial Settlement, the Company has agreed to expand its low-income discount to include recipients of Fuel Assistance. Also, the Attorney General and the Company agree in the Partial Settlement that the Company's compliance rates in the instant case will be designed to recover the total level of the discount based on the most recent number of actual recipients and a reasonable projection of the number of recipients to be added by the extension of the discount to Fuel Assistance recipients (Partial Settlement, article IV). The Partial Settlement leaves open the issue of what penetration rate should be used to determine the number of recipients to be added by the extension of the discount to Fuel Assistance recipients.

The Attorney General claims that 30 percent is a reasonable penetration rate for Fuel Assistance recipients to avail themselves of the low-income discount (Attorney General Brief,

p. 13). Also, the Attorney General states that, in order to be consistent with the Department's precedent, eligibility should be based on need, and the low-income discount should be expanded to include any residential customer who receives any form of needs-based public assistance (Attorney General Brief, p. 12). The Attorney General specifically recommends the addition of Medicaid and Refugee Resettlement to the low-income discount (id.). According to the Attorney General, the low-income discount should be a high priority, especially at a time when unemployment is high and public funding for Fuel Assistance has been reduced (id.). The Attorney General states that the Company has presented no basis for discriminating between needs-based public assistance programs applicable to the low-income discount and those not applicable (id., p. 13). Finally, the Attorney General states that expanding the eligibility of the low-income discount would not produce an unreasonable impact on the Company's non-participating customers (id.).

The Company maintains that it is reasonable to assume a 60 percent penetration rate for Fuel Assistance recipients for the following reasons: (1) most Fuel Assistance recipients will have an electric account in their name; (2) the Fuel Assistance program itself experiences a penetration rate over 70 percent of those who are eligible; (3) the Company expects that Fuel Assistance recipients would be more likely than recipients of other forms of aid to request the low-income discount because they are already receiving energy assistance; and (4) the close working relationship the Company has developed with community agencies that handle Fuel Assistance will contribute to a high penetration rate for this group (Company Brief, pp. 40-41, citing RR-DPU-38).

Further, the Company proposes that the Department permit it to collect or refund, as the case may be, any under- or over-recoveries of the amount of revenues in base rates associated with the discount.

Neither the Attorney General nor the Industrial Intervenors commented on the Company's proposal.

ii. Analysis and Findings

For the reasons noted by the Company above, the Department finds that the Company should assume a 60 percent participation rate for Fuel Assistance recipients who avail themselves of the low-income discount.

The record shows that, assuming a 60 percent penetration rate, approximately 600 Medicaid recipients and 12 Refugee Resettlement recipients would avail themselves of the low-income discount if it were expanded to include these two programs (RR-AG-12). Under current rates, the revenue impact of adding these two groups would be approximately $128,400 and would be $156,600 under the rates initially proposed by the Company (id.). Under the Partial Settlement, the revenue impact would fall somewhere between those two figures and, consequently, would be minimal. Therefore, the Department agrees with the

Attorney General that this would not produce an unreasonable impact on the Company's non- participating customers. Accordingly, the Department directs the Company to expand its low-income discount to include Medicaid and Refugee Resettlement recipients. Also, the Department directs the Company to continue its current outreach effort, expanded to include Fuel Assistance, Medicaid, and Refugee Resettlement recipients.

In setting base rates, the Department does not ensure dollar-for-dollar recovery by the Company of its costs and expected profits. Rather, rates reflect a representative level of expenses and a reasonable opportunity to earn the allowed return. Western Massachusetts Electric Company, D.P.U. 85-270, p. 194 (1986). Accordingly, the Department denies the Company's request to reconcile in the fuel clause any revenue amount from the low-income discount that is less than or greater than that which the base rates set in this docket are designed to recover.

c. General Service Rates

i. Rate 23 - Nonresidential Controlled Water Heating

Rate 23 is an optional controlled water heating rate available to all nonresidential customers (Exh. WM-10, p. 10). The Company proposed to increase the customer charge of Rate 23 from $13.25 to $16.50 per month, and to increase the energy charge from $0.07835 to $0.09641 per KWH. The Company asserted that this results in a fairly consistent increase of 17.0 percent over all levels of consumption (id., pp. 10, 75).

No intervenor commented on the proposed design of Rate 23.

The Department finds that at a $16.50 per month customer charge as proposed by the Company, the resulting bill impacts across all use levels are reasonable. Accordingly, the Department orders the Company to set the Rate 23 customer charge at $16.50 per month and to set the energy charge to collect the remaining base revenue requirement allocated to the Rate 23 class.

ii. <u>Rate 24 - Church Service</u>

Rate 24 is applicable to churches for lighting and incidental power in buildings set aside exclusively for public worship. The rate is closed, available only to customers who are presently receiving service under this rate (Exh. WM-10, p. 10).

The Company proposed to increase the customer charge of Rate 24 from $55.00 to $64.30 per month, increase the energy charge by approximately 3 mills from $0.06444 to $0.06722 per KWH, and set the demand charge at $3.00 per KW for all KW over 2 KW. The Company asserted that this results in a fairly consistent increase of 10.00 percent over all levels of consumption (<u>id</u>., pp. 10, 76).

No intervenor commented on the proposed design of Rate 24.

The Department finds that using the Company's proposed customer and demand charges does not violate continuity considerations, and is more consistent with the Company's standard general service rates. Accordingly, the Department orders the Company to set the customer charge for Rate 24 at

$64.30 per month, the demand charge at $3.00 per KW for all KW over 2 KW, and to set the energy charge to collect the remaining allowed base revenue requirement allocated to the Rate 24 class.

iii. Rates G-0, G-1, T-0, & T-3 - Small General Service

Currently, Rates G-0 and G-1 are available to general service customers whose loads do not exceed 349 KW (Exh. WM-11, pp. 40, 44). These rates are different only in the distribution voltage at which the customers are served: customers on Rate G-0 are served at either primary or secondary voltage levels and customers on Rate G-1 are served at only secondary distribution system voltage (id.). Rates T-0 and T-3 are the Company's optional TOU rates for G-0 and G-1 respectively (Exh. WM-10, p. 11).

The Company proposed to merge Rate G-1 with Rate G-0 because its cost of service study produced revenue requirements for Rate G-1 that would result in a rate higher than Rate G-0 for every level of demand and energy (Exh. WM-10, p. 11). The Company asserted that every customer on Rate G-1 would consequently transfer to the lower Rate G-0, causing a large revenue loss to the Company (id.). Proposed Rate G-0 was designed using the combination of billing statistics and revenue requirements of those customers on Rates G-0 and G-1. In Table 2 below are the Company's proposed and existing charges for Rates G-0 and G-1.

Table 2

Charges	Existing G-0	Existing G-1	Proposed G-0
Customer ($)	23.00	325.00	28.00
Demand ($/KW)			
First 50 KW	N/A	2.00	N/A
All Over 50 KW	N/A	11.63	N/A
All Over 2 KW	10.22	N/A	10.75
Energy (¢/KWH)	4.739	4.981	6.066

As mentioned above, the Company has proposed to consolidate Rate G-1 into Rate G-0. Correspondingly, the Company proposed to consolidate Rate T-3 into Rate T-0 (Exh. WM-10, p. 11). In Table 3 below are the Company's proposed and existing charges for Rates T-0 and T-3.

Table 3

Charges	Existing T-0	Existing T-3	Proposed T-0
Customer ($)	27.00	329.00	32.00
Demand ($/KW)			
First 50 KW	N/A	2.01	N/A
All Over 50 KW	N/A	11.70	N/A
All Over 2 KW	10.41	N/A	10.95
Energy (¢/KWH)			
Peak	5.288	5.508	7.189
Off-Peak	3.958	4.178	5.465

No intervenor commented on the proposed design of Rate G-0.

The Department finds the consolidation of Rate G-1 into Rate G-0, and correspondingly, Rate T-3 into Rate T-0 to be acceptable. Therefore, aside from the changes to marginal costs discussed supra, the Department finds the method used by the Company to design Rate G-0 to be reasonable. Accordingly, the Department directs the Company to set the Rate G-0 customer charge at $28.00 per month, the demand charge for all KW over 2 KW at full marginal capacity costs, and to set the energy charge to collect the remaining allowed recovery of base revenue requirement allocated to the Rate G-0 and G-1 classes. The Department directs the Company to set the Rate T-0 customer charge at $32.00 per month, the demand charge for all KW over 2 KW at full marginal capacity costs, and to set the energy charge to collect the remaining allowed recovery of base revenue requirement allocated to the Rates G-0 and G-1 classes.

iv. Rates G-2 and T-4 - Small General Service

Rate G-2 is available to general service customers whose loads do not exceed 349 KW and who are served at the primary distribution system voltage level (Exh. WM-11, p. 35). Rate T-4 is the Company's optional TOU rate for Rate G-2 (Exh. WM-10, p. 12).

For Rate G-2, WMECo proposed to increase the customer charge from $325.00 to $350.00 per month, increase the demand charge for the first 50 KW by $1.00 to $3.00 per KW, hold the demand charges for all over 50 KW constant at $10.82 per KW, and to increase the energy charges by approximately 7 mills. The bill impacts show a range of increases from 4.90 percent to 10.99 percent (id., pp. 12, 79).

The Company designed Rate T-4 to collect the revenue requirements of the G-2 rate class (id., p. 12).

No intervenor commented on the proposed design of Rate G-2 or T-4.

Aside from the changes to marginal costs discussed supra, the Department finds the method used by the Company to design

Rates G-2 and T-4 to be reasonable. Accordingly, the Department directs the Company to set the G-2 customer charge at $350.00 per month, the demand charges for 50 KW or less at $3.00 per KW, the demand charges for over 50 KW at full marginal capacity costs, and the energy charges to collect the remaining allowed recovery of base revenue requirement allocated to the G-2 rate class. The Department directs the Company to set the T-4 customer charge at $354.00 per month, the demand charges for 50 KW or less at $3.07 per KW, the demand charges for over 50 KW at full marginal capacity costs, and the energy charges to collect the remaining allowed recovery of base revenue requirement allocated to the G-2 rate class.

v. Rate T-2 - Large General Service

Rate T-2 is a mandatory primary distribution service TOU rate for general service customers with demands of 350 KW or greater (Exh. WM-10, p. 12). The existing and proposed Rate T-2 consists of six distinct customer charges. The customer charge for customers on Rate T-2 is a function of their most recent 12 months' maximum demands.

For Rate T-2, the Company proposed to increase the monthly customer charges uniformly by 20 percent, hold the demand charge constant, and maintain the differential between on-peak and off-peak marginal energy costs by increasing the on-peak energy charge by 11 mills and the off-peak energy charge by 8 mills (Exh. WM-10, p. 13).

(A) Positions of the Parties

(1) Industrial Intervenors

The Industrial Intervenors argue that the Department should adopt the changes which they proposed to the marginal energy costs, supra. In addition, the Industrial Intervenors state that if the rate increase originally requested by the Company is granted, strict adherence to the Department's marginal cost pricing concepts would result in unduly disruptive increases to the demand charge (Industrial Intervenors Brief, p. 22). The Industrial Intervenors point to Mr. Rosenberg's testimony to the effect that the demand charge should be limited to $12.65 per KW, a 5.86 percent increase from the current charge, the customer charge should be set at a 20 percent increase, and the energy charge should be set to collect the remaining allowed recovery of base revenue requirement allocated to the T-2 class (id.).

The Industrial Intervenors state that if the Department approves a rate increase significantly less than that originally proposed by the Company, the demand and customer charges proposed by Mr. Rosenberg should be retained and any reductions in revenue requirements for Rate T-2 should be recognized in the energy charges to the extent that this does not result in energy charges below current marginal costs (id.). To the extent that the reduction would result in energy costs below marginal energy costs, the Industrial Intervenors recommend that demand charges be reduced (id.).

The Attorney General did not comment on the Company's design of the T-2 Rate.

(2) The Company

The Company agrees that the changes to the marginal energy costs recommended by the Industrial Intervenors and discussed supra should be made. However, the Company states that the demand charges should remain at the levels proposed by the Company, with any reduction as a result of the Partial Settlement applied as a reduction to the customer charge (Company Brief, p. 37).

The Company also proposed to continue, with changes in unit prices, its Demand Reduction Rider ("DRR") applicable to proposed Rate T-2. Presently the DRR is available to any customer who is willing and able to interrupt at least 300 KW in at least four months of the year within one hour after being requested to do so by the Company (Exh. WM-11, p. 56). In addition to one-hour notice, the Company has proposed a new option of four-hours notice to interrupt and has proposed to reduce the term of the DRR from two years to one year (Exh. WM-10, pp. 14-15). This Rider is a complement to interruptible Rates I-1, I-2, and I-3 and the Voluntary Curtailment Rate, and is designed to encourage further load management (Exh. WM-10, p. 14). As with the Company's interruptible rates, customers are encouraged to interrupt load, but unlike the interruptible rates, the DRR has monthly and annual limits on the number of interruptions required. As such, the demand reduction credit of the DRR is less than the full avoided production and transmission costs reflected in the interruptible rates (id., pp. 42-44).

The Company proposed to maintain at current levels its credit for one-hour notice of $3.75 per KW if a customer agrees to six interruptions per month or $4.15 per KW for eight interruptions per month. Reflecting the reduced benefits to the Company of a longer notice period, the Company has proposed four-hour notice credits of $3.25 per KW and $3.65 per KW for six and eight interruptions per month respectively (id., p. 15).

(B) Analysis and Findings

In D.P.U. 89-255, the Department directed WMECo, for Rate T-2, to set the customer charge at the Company's proposed level, demand charges at full marginal capacity costs, and energy charges to collect the remaining allowed recovery of base revenue requirement allocated to the T-2 and G-3 classes combined. Id., p. 145. In the instant case, the Company contends that the remaining revenue allocated to the T-2 class should be collected through the customer charge. The Department finds no evidence on the record to support the Company's argument. Accordingly, the Department directs the Company to set the T-2 customer charges at the proposed levels, the demand charges at full marginal capacity costs, and the energy charges to collect the remaining allowed recovery of base revenue requirement allocated to the present T-2 rate classes combined. Also, the Department finds the Demand Reduction Rider to be acceptable as proposed by the Company.

vi. Transmission TOU Rate T-9

Rate T-9 is applicable only to "the entire use of electricity at a single location where service is taken at 69 KV or greater." Customers taking this rate may not resell the power received, and must take power through a single meter at any given location (Exh. WM-10, p. 45). The Company presently has one customer receiving service under this rate. WMECo proposed to lower the customer charge from $160,000 to $153,150 per month, maintain the demand charge at $7.73 per KW, increase the on-peak energy charge by approximately 10 mills, and increase the off-peak energy charge by approximately 7 mills (Exh. WM-10, p. 45; Exh. WM-11, p. 58).

No intervenor commented on the proposed design of Rate T-9.

Aside from the changes to marginal costs discussed supra, the Department finds the method used by the Company to design Rate T-9 to be reasonable. Accordingly, the Department directs the Company to set the T-9 customer charge at $153,150 per month, set the demand charge equal to marginal capacity cost, and set the energy charges to collect the remaining allowed revenue requirement by adjusting uniformly the on- and off-peak marginal energy costs.

vii. Interruptible Rates I-1, I-2, and I-3

The Company presently offers three interruptible rates. Rate I-1 is available to any primary voltage customer who agrees to interrupt at least 5,000 KW above the customer's firm demand level. Interruptible Rates I-2 and I-3 are available to any customer who agrees to interrupt a load of at least 300 KW above the customer's firm demand level. Rates I-2 and I-3 have been designed by the Company to differentiate between primary and secondary marginal distribution costs and energy costs (Exh. WM-10, pp. 53-59).

For Rate I-1 the Company has proposed to lower the threshold for participation from 5,000 KW to 2,500 KW, reduce the period of consequence for nonperformance from a maximum of five years to one year, add a maximum bill provision, and change unit charges to reflect updated marginal costs (id., p. 13). The only change proposed by the Company for Rates I-2 and I-3 was to change unit charges to reflect updated marginal costs.

Presently the Company has only one interruptible-load customer. The customer went on Rate I-3 on March 1, 1991 (Tr. IV, p. 51).

No intervenor commented on the proposed design of Rates I-1, I-2, and I-3.

The Department finds that the Company's rate design methods for Rates I-1, I-2, and I-3 are consistent with Department precedent in Western Massachusetts Electric Company, D.P.U. 87-260, pages 203-206 (1988). Accordingly, the Department directs the Company to set the customer charges for Rate I-1 and Rate I-3 equal to $925.00 per month, and for Rate I-2 equal to $577.55 per month. The Department orders the Company to revise the facilities and energy charges of these rates to reflect the marginal costs found to be appropriate by the Department in this Order.

viii. Partial Requirements Rates

(A) The Company's Proposal

The Partial Requirements ("PR") Rates apply to customers who self-generate all, or a portion of, their electrical power service requirements (Exh. WM-10, p. 60). For the PR Rate the Company has proposed to maintain the administrative fee at $300 per month, increase the primary distribution charge from $3.00 to $5.00 per KW, and increase the secondary distribution charge from $4.00 to $6.00 per KW.

(B) Positions of the Parties

The Industrial Intervenors state that on continuity grounds alone the Department should not allow the primary distribution charge to increase from $3.00 to $5.00 per KW. In addition, the Industrial Intervenors assert four reasons why the Company's marginal distribution study overstates marginal primary distribution capacity costs (Industrial Intervenors Brief, p. 23).

First, according to the Industrial Intervenors, the Company is unable to disaggregate investments used to meet new load from investments used to replace and upgrade equipment handling existing load (id.). Second, it cannot be determined whether or not the Company is overbuilding its distribution system in the short run, because the estimated distribution plant additions are divided by anticipated load growth, as opposed to the nameplate rating of the equipment included in the distribution plant additions. Third, since the Company does not differentiate its primary distribution plant by voltage level, high voltage users are allocated low voltage equipment. Lastly, the Industrial Intervenors state that the Company's marginal distribution cost study assumes that all the investment in distribution plant is attributable to growth in demand, whereas the record supports that a portion of the distribution plant investment is customer-related (id., p. 24).

The Industrial Intervenors argue that, because the Company has not sustained its burden of proof, the Department should maintain the present primary demand charge until the issues they raised have been adequately considered (id.).

Also, the Industrial Intervenors state that the PR Rate presumes that the first power through the meter is the higher cost supplemental power, and that the balance is the lower cost standby power.[5] This gives any benefit of the doubt as to whether the customer is using the power as supplemental or

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5 The PR Rate applies to a customer that self-generates all or a portion of its electrical power service requirements. The power taken by the Customer over and above its own electrical generation is defined as supplemental power and is charged as any full requirements customer would be charged. When the customer experiences a scheduled outage, back-up power is provided. When the customer experiences a forced outage, maintenance power is provided. Maintenance and back-up power, which collectively are referred to as stand-by power, are priced lower than supplemental power.

standby to the Company. However, according to the Industrial Intervenors, in the case when the customer has scheduled a maintenance outage with the Company, the customer is utilizing the standby power first and the balance as supplemental power (id.).

To correct the asserted bias in the rate, the Industrial Intervenors argue that the definition of supplemental demand in the tariff should be amended to read as follows:

> The Supplemental Demand for the billing month in which there is no maintenance shall be the lower of the Supplemental Contract Demand for the current period or the actual billing demand as determined under the applicable General Service Tariff. During periods of maintenance that have been approved by the Company (as specified on Page 5 of the Tariff) Supplemental Demand will be defined as metered demand, if any, over and above the Firm Back-up Contract Demand.

Id., p. 26.

The Company states that it has computed marginal costs following methodologies approved by the Department. The $5.00 per KW primary distribution charge is supported by the Company's marginal distribution cost study. The Company agrees that a study of the calculation of marginal demand costs may have merit, and it is willing to examine the issue in its next base rate filing. However, until the results of such a study are presented to the Department, it asserts that the proposed pricing for the distribution demand charge should be accepted (Company Brief, p. 38).

With regards to the Industrial Intervenors' argument that the Company's PR Rate proposal should be rejected because increasing the primary distribution charge from $3.00 to $5.00 per KW violates the Department's continuity goal, the record shows that the monthly charge to customers on the PR Rate is the sum of the administrative fee, the customer service charge, the distribution demand charge, the production/transmission demand charge for supplemental power, the production/transmission demand charge for back-up power, and the energy charges (Exh. WM-10, p. 63). Consequently, the primary distribution charge is only a small fraction of the total charge to customers on the PR Rate. Accordingly, a large percentage increase to the primary distribution charge does not mean that customers on the PR Rate will have a large percentage increase to their total bill, thereby violating the Department's continuity goal. Therefore, the Department disagrees with the Industrial Intervenors assertion that the Company's proposed PR Rate should be rejected on continuity grounds.

Regarding the Industrial Intervenors argument that the definition of supplemental power in the tariff be amended, the Company contends that customers on the PR Rate prefer self-generation to purchases from the Company. Therefore, according to WMECo, the customer is always motivated to utilize its generation to its economic maximum. Accordingly, the Company contends that the customer's generation most probably operates in the fashion of a baseload unit, whereas it is billed as if it operated as a load-following, peaking unit. Therefore, the Company agrees with the Industrial Intervenors' proposal.

However, the Company contends that it is limited to the period of scheduled maintenance, the production/transmission demand component of Rate PR, and only to the difference in the number of KW on Back-up Service and the number on Supplemental Service (id., p. 39).

(C) Analysis and Findings

Both the Industrial Intervenors and the Company agree that a study of the calculation of marginal demand cost should be performed in the Company's next base rate filing. However, in the instant case the Industrial Intervenors argue that the Company should maintain the status quo and keep the distribution charge at its current rate of $3.00 per KW. The Company maintains that the distribution charge was computed following methodologies approved by the Department and should be increased to marginal cost, which is $5.00 per KW.

The Department finds that the Company's marginal distribution cost study followed the Department's methodology approved in WMECo's last rate case, D.P.U. 89-255. Accordingly, the Department finds that the Company's primary and secondary distribution charges for this case should be set at the marginal costs determined by the Company in its filing. The Department directs the Company in its next base rate filing to address the merits of the four issues, discussed supra, that the Industrial Intervenors raised about the Company's marginal distribution cost study.

The Company agrees with the Industrial Intervenors' contention that during times when the customer has scheduled a maintenance outage with the Company, WMECo should assume that the first power through the customer's meter is back-up power (i.e., the power that the customer would have self-generated if its generator were not out of service for maintenance), and the remainder of the power through the customer's meter is supplemental power. Accordingly, the Department directs the Company in its compliance filing to amend its Partial Requirements Tariff to comply with the above change.

The Department orders the Company to revise the tariffs of the PR rate class to reflect the marginal costs found to be appropriate by the Department in this Order.

d. Street and Security Lighting Rates S-1 and S-2

The Company designed its proposed street lighting rates so that customers using high-pressure sodium lighting receive smaller increases than those that use mercury vapor or incandescent lighting. The Company asserted that it designed the proposed streetlighting rates on the basis of the principle accepted by the Department that the cost of high-pressure sodium lights is deemed to be the marginal cost of lighting (Exh. WM-10, p. 14).

No intervenor commented on the design of Rates S-1, or S-2.

Aside from the changes to marginal costs discussed supra, the Department finds the method used by the Company to design Rates S-1 and S-2 to be reasonable. The Department directs the Company to modify these rates in accordance with the cost-of-service allocation and the marginal costs found to be appropriate by the Department in this Order.

e. Transitory Demand Rider

The Company has proposed a Transitory Demand Rider applicable to general service customers who incur large temporary demand increases on rare occasions known in advance. Presently, such an increase results in the customer being placed on a mandatory general service rate. The Company proposed that it may waive rate consequences of that demand if the customer has given three-months advance notice, providing the demand increase is of limited enough duration, thereby causing the Company no incremental cost (Exh. WM-10, p. 15).

No intervenors commented on the transitory demand rider.

The Department finds the Transitory Demand Rider proposed by the Company is acceptable as proposed.

f. Optional Time-Of-Use Rates

In the Company's last rate case, D.P.U. 89-255, the Department stated the following:

> The Department does direct the Company, in its next rate proceeding, to propose mandatory TOU rates for the G-0, G-1, and G-2 rate classes that would satisfy the Department's rate design goals. In its TOU rate design proposal, the Department directs the Company to investigate the following: (1) determine the level of demand above which it makes economic sense to implement mandatory TOU rates for general service customers; (2) investigate the possibility of creating separate rate classes for small- and large-use customers in the G-0, G-1, and G-2 classes when designing TOU rates; (3) investigate the possibility of phasing-in the rate differentials between peak and off-peak rates; (4) collect sufficient billing and load data to determine the bill impacts of mandatory TOU rate proposals.

Id., pp. 133-134. Also, the Department directed the Company to implement its optional residential TOU rate design consistent with the above findings (id., p. 124).

In the Company's initial filing in the instant case, it failed to comply or report on the status of the Department's directives stated above. When the Department sought an explanation (Exh. DPU-44 and Exh. DPU-45), the Company stated that it could not meaningfully address the Department's directives until after the issuance of D.P.U. 89-255-C (Exh. DPU-44). D.P.U. 89-255-C was issued on October 18, 1990, which was 2½ months before the Company filed the instant case. The Company stated that 2½ months was not sufficient time to address the Department's directives (id.). Moreover, the Company stated that the optional TOU rates have not yet attracted the expected number of customers. Presently, the Company has only one optional TOU rate customer (Tr. IV, p. 109). Consequently, the Company has little data to determine what kind of impact TOU rates will have on customers' consumption patterns and what benefits accrue for the additional cost of metering (id.).

Because it would be advantageous for many of its customers to switch to optional TOU rates (Exh. WM-10, p. 5), the Department finds that the Company needs to make its customers more aware of its optional TOU rates. Accordingly, the Department orders the Company to prepare a general customer education plan on TOU rates and to file it with the Department within 60 days of its compliance filing. Further, the Department orders the Company to update the general customer education plan and include it in its next rate proceeding. See Fitchburg Gas and Electric Light Company, D.P.U. 90-122, page 67 (1990).

The Department agrees that time considerations made compliance difficult. However, the Department's directives in D.P.U. 89-255, pages 124, 133, and 134 still need to be addressed. Accordingly, we order the Company to do so in its next rate proceeding.

F. Line-Extension Policy

In Western Massachusetts Electric Company, D.P.U. 90-68 (1991), in response to an issue raised by an individual customer (Mr. Brooks) the Department stated:

> WMECo's Terms and Conditions lack a provision for reimbursement if other customers, within a reasonable time period, use a line paid for by the first customers in a region. WMECo's line extension policy differs from that of other large electric utilities in that other companies allow for reimbursement of a customer who pays for a line extension, in the event that new customers, within a reasonable time period, later tap into the line.
>
> The Department questions the reasonableness of this provision in WMECo's Terms and Conditions and directs the Company to address in its pending rate case, D.P.U. 90-300, the reimbursement question raised by Mr. Brooks' petition. Accordingly, WMECo is ordered to file testimony and relevant data regarding its reimbursement policy. The Company should file a draft amendment to its Terms and Conditions that would provide for such reimbursement and shall comment on the merits of such a change in its prefiled testimony.

Id., pp. 6-7.

In response to the Department's order in D.P.U. 90-68, the

Company proposed to allow a customer who initially requests a line extension ("original customer") one pole and one span of conductors at no charge. For line extensions beyond one span of conductors, the customer would be required to pay the Company a fee in advance that is equivalent to the Company's construction cost of the line extension beyond the first free span of conductors, including the purchase of materials, labor charges, tree-trimming, and any other costs incurred by WMECo. The total line-extension cost would be divided by the total number of spans of conductors to determine an average price of one pole and span of conductors. This becomes the basis for determining any future refund to be made to the original customer (Exh. WM-9, p. 3).

The Company proposed as its reimbursement policy that in the event that any additional customer requests service at any point along a line previously extended to serve the original customer, including a second line extension at the end of the original extension, the new customer would be allowed one pole and one span of conductors at no charge, and the original customer would be eligible for a refund from the Company in the amount equal to the average price of one pole and span of conductors as determined above. This procedure would continue until the expiration of the four-year refund period or until the original customer's fee has been refunded in its entirety. In no instance would the original customer receive refunds that total more than the fee originally paid by that customer (id., p. 4).

In support of its proposed policy the Company states that prior to February 1, 1985, WMECo's line-extension policy provided for a pro-rata refund to a customer who paid for a residential line extension if additional customers requested service from that line within a four-year period. The method used to determine the amount of reimbursement resulted in an administratively complex and burdensome refund calculation, according to the Company. As a result, on February 1, 1985, WMECo eliminated its reimbursement policy and adopted a new policy under which it would provide up to three poles and three spans of conductors per customer at no cost to the customer (Company Brief, pp. 41-42).

The Company contends that a one pole and one span of conductors allowance is justified on the basis of a cost analysis it prepared (id., citing Exh. WM-9, Exh. CJR-1). WMECo maintains that the refund method proposed is less administratively burdensome than the process followed by the Company prior to 1985. Therefore, the Company states that the Department should accept WMECo's proposed residential, line-extension policy (id., p. 43).

According to its cost analysis, the Company can support an investment of $236.43 for each residential line extension (Exh. WM-9, exhibit CJR-1). The Company's installed cost of one pole and its associated equipment and conductors is $1,385 without joint billing credit or $1,195 with joint billing credit (i.e., sharing a pole with the telephone company). Accordingly, the Department finds that the cost analysis prepared by the Company supports changing the allowance to a residential customer requesting a line extension from three poles and three spans of conductors to one pole and one span of conductors with a provision for possible reimbursement to the original customer of additional money paid, as new customers come on the line (id.).

However, the Department finds that the reimbursement policy proposed by the Company may be unfair to the original customer, as shown in the following example. Assuming that the original customer's line extension requires five poles and five spans of conductors, at the time of construction, the original customer is charged the cost of five poles and five spans of conductors less the cost of one pole and one span of conductors. If a second customer requests a line extension that shares four of the poles of the original customer's line extension and requires no additional poles, the original customer is reimbursed the cost of one pole and one span of conductors and the second customer is not charged at all. This results in the original customer paying for three poles and three spans of conductors that are also being used by the second customer at no cost. The Department does not accept the Company's proposed line-extension policy and directs the Company to develop a new residential line-extension policy. Pending the approval by the Department of a revised line-extension policy, the Company's current policy of providing three poles and three spans of conductors shall remain in effect.

VI. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 780 through 805, inclusive, filed by Western Massachusetts Electric Company on December 14, 1990, be and hereby are DISALLOWED; and it is

FURTHER ORDERED: That Western Massachusetts Electric Company file new schedules of rates and charges designed to produce additional gross revenues of $32,211,000; and it is

FURTHER ORDERED: That Western Massachusetts Electric Company shall file all rates and charges required by the Order and shall design all such rates in compliance with this Order; and it is

FURTHER ORDERED: That Western Massachusetts Electric Company shall comply with all other orders and directives contained herein; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/ ROBERT C. YARDLEY, JR.

Robert C. Yardley, Jr., Chairman

/s/ BARBARA KATES-GARNICK

Barbara Kates-Garnick, Commissioner

/s/ MARY CLARK WEBSTER

Mary Clark Webster, Commissioner

A true copy
Attest;

MARY L. COTTRELL
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).