INNOVATIVE RATES
FOR GENERAL SERVICE CUSTOMERS
OF THE CENTRAL MAINE POWER COMPANY

prepared for

THE MAINE PUBLIC UTILITIES COMMISSION

by

RESOURCE PLANNING ASSOCIATES, INC.

in behalf of

THE NATIONAL REGULATORY RESEARCH INSTITUTE
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FOREWORD

This report was prepared by Resource Planning Associates, Inc. for The National Regulatory Research Institute (NRRI) under Contract No. EC-77-C-01-8683 with the U.S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the contractor and do not reflect the opinions nor the policies of either the NRRI or DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utilities regulation.

The NRRI appreciates the cooperation of the Maine Public Utilities Commission with the contractor in preparing this study and for their permission to make this information available to others interested in regulatory affairs.

Douglas N. Jones
Director

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Introduction

As part of its continuing evaluation of the retail rates charged by Central Maine Power Company (CMP), the Maine Public Utilities Commission (PUC) initiated Docket U. #3325, "Investigation into the Design of Rates Available to Commercial and Industrial Customers." Specifically, this investigation focuses on the retail rates for all but the 10 largest general service (i.e., commercial and industrial) customers served by CMP.[1]

As part of this investigation, the PUC ordered CMP to file flat and optional time-of-day (TOD) rates for its three general service customer groups by February 1, 1979. These rates were supposed to be designed to produce approximately $75 million in revenue, the revenue level approved for these customers by the PUC in CMP's most recent general retail rate case (Docket F.C. #2332). CMP also submitted alternative flat and TOD rates to the PUC on March 18, 1979. The PUC requested that the National Regulatory Research Institute (NRRI) provide the commission with technical assistance in evaluating these rates and in preparing alternative flat and TOD rate structures if necessary.

In response to the PUC's request, NRRI retained Resource Planning Associates, Inc. (RPA), to evaluate the rates filed by CMP, identify any deficiencies in the rates, and design alternative rates to eliminate such deficiencies.

In undertaking this evaluation, RPA attempted to determine if the rates filed by CMP: (1) were based on accepted ratemaking practices and methodologies; and (2) promoted the achievement of the ratemaking standards established by the Public Utility Regulatory Policies Act (PURPA) of 1978.

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1. Flat and time-of-day rates for the 10 largest general service customers were approved by the PUC in its October 31, 1978, order in Docket F.C. #2332.

Our analysis of CMP's existing and proposed general service rates was based solely on cost studies and other data provided by CMP. These data were limited for three reasons: (1) no explicit cost justification was given for the customer group revenue requirements established by the PUC; (2) CMP's cost-of-service study was conducted for the test year 1977; and (3) no time-differentiated cost study had been done. After analyzing CMP's rates and identifying their deficiencies, we developed alternative general service flat rates. We were unable to develop alternative TOD rates because no time-differentiated cost study was available on which to base such rates.

On the basis of our evaluation of the flat rates, we concluded that the flat rates filed by CMP on February 1 reflect the unit demand, energy, and customer costs of serving average-usage customers in each of the three general service customer groups.[2] CMP's rates of March 18 do not accurately reflect these costs. We also found that the embedded cost-of-service study on which the February 1 rates are based is well documented and represents an in-depth understanding of embedded cost-of-service analysis. Nonetheless, we did identify two minor deficiencies that have been eliminated in the alternative flat rates designed by RPA.

Therefore, we recommend that the PUC implement the alternative RPA flat rates, which are designed to reflect the cost of serving average-usage customers at both primary and secondary voltage levels, instead of reflecting an average cost of serving these customers. In addition, we have designed our rates to ensure that the energy charges in the RPA flat rate for large general service customers are never less than the off-peak energy charge in CMP's optional TOD rate that is currently offered to the company's 10 largest general service customers served at transmission voltage levels.

From our analysis of CMP's optional TOD rates, we concluded that CMP did not use a time-differentiated cost study as a basis for setting peak and off-peak demand and

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2. Average-usage customers within a customer group are those customers whose demands, kilowatt-hour (kWh) consumption, and load factors are equal to the average for the group.

energy charges in these rates. Therefore, these rates should not be offered to customers, even on an optional basis. We recommend that the PUC require CMP to develop an updated time-differentiated cost study based either on embedded or marginal costs and design new TOD rates to reflect the results of this updated study. These new rates should then be thoroughly examined to determine their revenue effects and the degree to which they reflect time-related cost differentials.

In the remainder of this report, we present the analytical results on which our conclusions and recommendations concerning CMP's flat and optional TOD rates are based. Specifically, in Chapter 1, we describe the issues involved in our evaluation of the flat rates and the results of our analysis, and present alternative flat rates for each of CMP's three general service customer groups. In Chapter 2, we discuss the results of our analysis of CMP's optional TOD rates and the reasons why these rates should not be offered to customers.

1 FLAT RATES

Because the Maine PUC feels that declining block rates may no longer be appropriate indicators of a utility's cost of generating, transmitting, and distributing electricity, the commission ordered CMP to file flat general service rates for all general service customers, except its 10 largest. CMP uses three customer group designations to identify general service customers receiving electricity at distribution voltage levels: small general service (SGS) customers having maximum demands less than 8 kilowatts (kW); medium general service (MGS) customers having maximum demands between 8 kW and 199 kW; and large general service (LGS) customers having maximum demands greater than 199 kW.[1] The three general service rates currently in effect for these customers are Rates GS-1, GS-2, and GS-3. SGS customers are billed using Rate GS-1; MGS customers may be billed at either Rates GS-1 or GS-2, depending on their maximum demand and load factor; similarly, LGS customers may be billed at Rates GS-2 and GS-3.

On February 1, 1979, CMP filed three flat general service rates to be considered by the PUC: Rates TR-1, TR-2, and TR-3. Exhibit 1.a gives CMP's existing general service rates, its flat rates filed on February 1, its alternative flat rates filed on March 18, and the alternative flat rates designed by RPA.

To evaluate the flat rates filed by CMP on February 1, we reviewed:

- The PUC order in Docket F.C. #2332, which was CMP's most recent general retail rate case

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1. LGS customers receiving electricity at transmission voltage levels (minimum of 30 kilovolts) and having maximum demands of at least 2,000 kW are classified as general service transmission (GST) customers. In Docket F.C. #2332, the PUC approved a flat rate (Rate GST) and an optional TOD rate (Rate GST-TD) for GST customers.

Exhibit 1.a

General Service Flat Rates for CMP
($)

Existing Rates		Proposed Rates		Proposed Rates (Revised)		Alternative Rates (RPA)	
GS-1		**TR-1**		**TR-1A**		**RPA-1**	
6.50	per customer per month	7.50	per customer per month	6.50	per customer per month	7.50	per customer per month
3.85	per kW in excess of 8 kW of monthly billing demand[a]	6.00	per kW in excess of 8 kW of monthly billing demand[a]	3.85	per kW in excess of 8 kW of monthly billing demand[a]	5.75	per kW in excess of 8 kW of monthly billing demand[a]
0.0443	per kWh for first 750 kWh	0.03315	per kWh	0.0396	per kWh for first 1,500 kWh	0.03425	per kWh
0.0190	per kWh in excess of 750 kWh			0.0127	per kWh in excess of 1,500 kWh		
GS-2		**TR-2**		**TR-2A**		**RPA-2**	
35.00	per customer per month	15.00	per customer per month	21.00	per customer per month	18.00	per customer per month
2.30	per kW of monthly billing demand[a]	48.00	for first 8 kW or less of monthly billing demand[a]	29.60	for first 8 kW or less of monthly billing demand[a]	43.04	for first 8 kW or less of monthly billing demand[a]
0.0190	per kWh for first 5,000 kWh	6.00	per kW in excess of 8 kW	3.70	per kW in excess of 8 kW	5.38	per kW in excess of 8 kW
		0.0015	per kWh	0.0127	per kW	0.0041	per kWh
0.0190	per kWh for next 150 kWh per kW of monthly billing demand						
0.0147	per kWh for next 150 kWh per kW of monthly billing demand						
0.0116	per kWh in excess of above						

Exhibit 1.a (continued)

General Service Flat Rates for CMP
($)

Existing Rates		Proposed Rates		Proposed Rates (Revised)		Alternative Rates (RPA)	
GS-3		**TR-3**		**TR-3A**		**RPA-3**	
750.00	per customer per month	55.00	per customer per month	111.00	per customer per month	90.00	per customer per month
2.30	per kW of monthly billing demand[a]	1160.00	for first 200 kW or less of monthly billing demand[a]	975.00	for first 300 kW or less of monthly billing demand[a]	922.50	for first 250 kW or less or monthly billing demand[a]
0.0166	per kWh for first 150 kWh per kW of monthly billing demand	5.80	per kW in excess of 200 kW	3.25	per kW in excess of 300 kW	3.69	per kW in excess of 250 kW
0.0069	per kWh for next 150 kWh per kW of monthly billing demand	0.0015	per kWh	0.00808	per kWh	0.0090	per kWh for first 150,000 kWh
0.0060	per kWh in excess of above					0.0039	per kWh in excess of 150,000 kWh

[a] 80-percent, 11-month ratchet.

- Testimony of Frederick Anderson in Docket F.C. #2332 (Mr. Anderson is the director of CMP's rate department)
- CMP's comments filed in Docket U. #3325 on February 1, 1979
- The embedded cost-of-service study filed by CMP in Docket U. #3325
- CMP's responses to PUC requests for data and information dated February 5, 1979, and May 11, 1979.

On March 18, 1979, CMP filed alternative flat general service rates that, in the company's opinion, would produce more moderate changes in general service customers' bills than those rates submitted on February 1. These rates are shown in Exhibit 1.a as Rates TR-1A, TR-2A, and TR-3A.

After analyzing both the February 1 and March 18 rates, we designed alternative general service flat rates that are shown as Rates RPA-1, RPA-2, and RPA-3 in Exhibit 1.a. These rates were designed to recover the total cost of serving general service customers and to reflect, as much as possible, the estimated unit demand, energy, and customer costs of each of the three general service customer groups.

On the basis of our evaluation of CMP's February 1 and March 18 rates and a comparison of CMP's existing general service rates with the estimated unit costs derived from CMP's embedded cost-of-service study, we recommend that the PUC implement the alternative flat rates designed by RPA. Although CMP's February 1 rates generally reflect the unit costs of serving average-usage customers in each of the three general service customer groups (the March 18 rates do not accurately refect unit costs), we believe that the alternative RPA rates are superior for two reasons. First, the RPA rates reflect unit costs of serving average-usage customers at both the primary and secondary voltage levels, rather than at an average level. Second, the tail block rate in our rate for GS-3 customers (Rate RPA-3) is equal to the off-peak energy rate component of CMP's Rate GST-TD, which is the company's TOD rate offered on an optional basis to its 10 largest general service customers.[2] The flat energy charge for GS-3 customers must be set at least equal to the off-peak energy charge for GST customers to keep from giving GS-3 customers a price signal that says the average cost of providing electricity to them is less than the off-peak energy cost of providing electricity to large customers served from CMP's transmission system.

Although one of the objectives of designing electricity rates is to ensure that prices charged customers reflect the costs of serving those customers, three ratemaking constraints may limit the degree to which both the RPA rates and the CMP rates reflect the actual unit cost of serving general service customers.

First, the estimated unit costs used to derive the RPA and CMP rates were based in part on the revenue requirements for each customer group, and no explicit cost justification is given for the customer group revenue requirements established by the PUC. These revenue requirements were established in CMP's last general retail rate case when the PUC ordered CMP to implement an across-the-board percentage rate increase to produce the additional retail rate revenue allowed by the commission.

Second, the cost-of-service study on which the RPA and CMP rates are based is for the test year 1977. Thus, these flat rates are based on 2-year-old cost and load data. The costs and revenue requirements allocated to each customer group derived from a 1979 test year cost-of-service study would differ from those derived from the 1977 test year study.

Third, because adequate load research data were not available from CMP's load research program, CMP was forced to use Bary curves and assumed load factors for several of the general service customer groups. Consequently, the allocation factors used in the 1977 cost study may be inaccurate.

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2. The GST-TD rate consists of: $1000 charge per customer per month; $3.24 per kW of monthly peak billing demand; $0.30 per kW of monthy excess building demand; $0.0060 per kWh during peak periods; and $0.0039 per kWh during off-peak periods. The monthly peak billing demand includes an 80-percent, 11-month ratchet.

Although the PUC should be aware of these three rate-making problems, these problems are not severe enough to justify delaying a decision to implement the RPA alternative flat rates for general service customers. The RPA rates are based on CMP's well-done cost-of-service study and, as such, should encourage customers to use electricity efficiently.

In the following sections, we describe the steps in our evaluation of CMP's rates and the development of alternative flat rates. Specifically, we discuss three ratemaking issues affecting our rate design and describe the methods used to determine unit costs, the monthly revenue requirements, and the rate design equations used to derive the energy and demand charges in the RPA flat rates.

RESOLUTION OF RATEMAKING ISSUES

During our evaluation of CMP's flat rates filed on February 1 and March 18, we identified three ratemaking issues that should be resolved:

1. The appropriateness of applying CMP's Rate GS-1 to both SGS and MGS customer groups

2. The justification for including demand ratchets in the rates

3. The need for seasonal rate differentials.

In the following sections, we discuss each of these issues.

Appropriate Application of Rate GS-1

An important basic question is whether or not CMP's Rate GS-1 should be applicable to both customers with estimated billing demands of 8 kW or less whose demands are not metered and customers with estimated billing demands exceeding 8 kW whose kW and kWh consumption is metered.

Fred Anderson, director of CMP's rate department, testified in Docket F.C. #2332 that it was impossible to design Rate GS-1 to contain both a customer charge and flat demand and energy charges. Mr. Anderson stated that, if the rate "contained a flat energy charge, it would be necessary either to: (1) design a new rate for those customers with demands of 8 kW or less; or, (2) install demand meters on those customers with demands of 8 kW or less and charge a demand charge."[3] CMP disregarded Mr. Anderson's testimony in filing Rates TR-1 and TR-1A. As shown in Exhibit 1.a, neither of these rates has a demand charge for SGS customers with demands of less than 8 kW. The demand costs created by these customers, therefore, are recovered primarily in the energy charges in these rates.

We agree with Mr. Anderson that, theoretically, unless the demand charge is applied to all kW demands, including demands of less than 8 kW, two rates should be developed for SGS customers in order for the flat demand and energy charges to accurately reflect the diverse load factors and load patterns in this class of nonhomogeneous customers. However, from a practical point of view, it may not be cost-effective either to meter kW demands of very small SGS customers (the single rate alternative) or to develop two SGS flat rates. Therefore, we believe that, at this time, a single flat rate is appropriate for SGS customers. Moreover, a single flat rate (i.e., Rate RPA-1) can be designed to promote efficient electricity consumption and recover cost of service in an equitable manner from SGS customers.

Justification for Demand Ratchets

In CMP's last general rate case (Docket F.C. #2332), one issue that arose was whether or not demand ratchets should be used in CMP's rates. Demand ratchets are included in rates to (1) recover demand-related costs in a uniform manner over a long time period (e.g., 12 months) and (2) substitute for seasonally differentiated demand charges. However, the use of non-time-differentiated demand ratchets creates two problems that may conflict with the conservation, efficiency, and equity goals of PURPA.

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3. Rebuttal testimony of Fred Anderson before the Maine PUC, Docket F.C. #2332, p. 9, lines 18-21.

First, if a non-time-differentiated demand ratchet is used in a rate, the demand charge(s) in the rate must be set below actual demand-related costs and the energy charge(s) set above actual energy-related costs to collect the appropriate level of revenue from the customer group to which the rate is applicable. Thus, the demand and energy price signals received by customers are distorted and may cause customers to make inefficient choices between the amount of power demanded (kW) and the amount of energy used (kWh).

The second, and perhaps more serious, problem in using non-time-differentiated demand ratchets is that they penalize customers whose peak demand occurs during the system's off-peak periods. For example, a general service customer (such as a bakery) that normally reaches its peak demand during CMP's daily or seasonal off-peak periods is forced to pay the same annual level of demand-related revenue as a customer whose peak demand occurs during CMP's daily or seasonal system peak (e.g., a restaurant with daily hours from 8 a.m. to 10 p.m.). Furthermore, if a rate has a non-time-differentiated demand ratchet, a customer billed under this rate will have no incentive to shift his peak demand from the system's peak demand period to the system's off-peak demand period. Peak demand shifts from peak to off-peak periods would improve CMP's system load factor and the efficiency of electricity production and consumption. However, because of the non-time-differentiated demand ratchets, customers would receive no monetary benefits from shifting demands and, therefore, would have no incentive to make the shift.

In addition, CMP's contention that demand ratchets promote conservation is debatable.[4] If we define conservation as reductions in kW demands, demand ratchets probably do encourage conservation. However, if we define conservation as a reduction in energy used (i.e., kWh), it is unlikely that demand ratchets promote conservation directly. But, as we mentioned earlier, in rates with non-time-differentiated demand ratchets, the energy charges typically must be set above actual energy-related costs to collect the appropriate level of revenue from customers. To the extent that these higher-

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4. See the rebuttal testimony of Fred Anderson before the Maine PUC, Docket #2332, pp. 6-8.

than-necessary energy charges reduce kWh consumption, one can say that demand ratchets indirectly promote conservation.

Despite the potential problems associated with the use of non-time-differentiated demand ratchets, demand ratchets may be necesary in flat rates. When a three-part flat rate is applied to a nonhomogeneous customer group, such as SGS customers, an appreciable portion of this group's demand-related costs must be covered in the flat energy charge (to recover total costs accurately). Thus, we have included non-time-differentiated demand ratchets in our alternative rates as a compromise between the necessity of recovering total cost of service and the desire to provide proper price signals to customers and to treat all customers as equitably as possible.

However, we urge the PUC to examine more closely the issue of whether or not CMP's non-time-differentiated demand ratchets penalize general service customers who set peak demands during CMP's off-peak periods. If some customers are being penalized, the PUC should remove this inequitable and inefficient rate burden from these customers by requiring CMP to base these customers' billing demands on their demands during CMP's peak demand periods.

Need for Seasonal Rate Differentials

Seasonal rate differentials are not included in CMP's flat general service rates, even though the results of a study completed by National Economic Research Associates (NERA) indicates that CMP's winter peak load will continue to exceed its summer peak load by 24 percent in each power year from 1976 to 1987.[5] (See Exhibit 1.b.) Moreover, the NERA marginal cost study indicates that about 80 percent of CMP's generating-capacity costs should be assigned to the winter season (i.e. November to February).

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5. NERA, An Anaysis of the Time-Differentiated Marginal Cost of the Central Maine Power Company, March 28, 1978, Schedule 2, p. 1.

Exhibit 1.b

CMP Seasonal Peak Load Data

Year	Summer Peak (MW)	Growth Rate (%)	Winter Peak (MW)	Growth Rate (%)	Seasonal Differential (MW)
1978	953	–	1,188	–	235
1979	999	4.83	1,252	5.39	253
1980	1,047	4.80	1,315	5.03	268
1981	1,097	4.78	1,381	5.02	384
1982	1,148	4.65	1,446	4.71	298
1983	1,202	4.70	1,513	4.63	311
1984	1,256	4.49	1,583	4.63	327
1985	1,314	4.62	1,654	4.49	340
1986	1,373	4.49	1,725	4.29	352
1987	1,435	4.52	1,803	4.52	368
1978-1987	–	4.65	–	4.74	–

SOURCE: CMP, Data Response Item 11 (1FES-11).

CMP is presently a winter-peaking system -- the difference between CMP's winter and summer system peaks is currently about 250 megawatts (MW). Between 1978 and 1987, the winter peak is expected to grow at a 4.74-percent effective annual growth rate, compared to an effective annual growth rate for the summer peak of 4.65 percent. By 1987, the difference between the winter and summer peaks is expected to reach approximately 370 MW. If this faster growth in the winter peak is realized and a seasonal rate differential is not implemented, CMP's annual load factor will decrease, and there will be an unjustified increase in the average price of electricity during the nonwinter months.

Because consumers make energy-related investment decisions, such as the installation of more-efficient space-heating equipment, at least in part on the basis of relative electricity prices, it is important that any seasonal differential that is implemented accurately reflects CMP's relative cost differential of providing electricity in the winter and summer. However, there are not sufficient data and information to determine if a significant seasonal cost differential exists. Therefore, we are unable to determine if seasonal rate differentials should be included in the general service rates at this time.

Although the absolute MW difference in CMP's current and anticipated seasonal peaks is small, this difference may significantly affect CMP's capacity expansion plans, its operating costs, and its ability to perform maintenance on its generating units. If CMP'S installed capacity costs and operating and maintenance expenses are not invariant with respect to the company's seasonal demands, seasonal rate differentials should be implemented. To determine if the seasonal difference does affect capacity expansion plans and the company's operating and maintenance expenses, sensitivity analyses should be performed. These analyses should reflect CMP's membership in the New England Power Pool (NEPOOL), the company's installed capacity obligations and operating and maintenance procedures under the NEPOOL agreement, and the capacity options available to CMP through joint ventures with other NEPOOL members. CMP's seasonal load forecasts should also be examined more closely to determine the accuracy of the forecast demands. This examination should include a through analysis of the data and the analytical methods used to perform the forecasts.

Therefore, we recommend that the PUC require CMP to conduct the analyses described above to determine if seasonal rate differentials should be implemented.

DETERMINATION OF UNIT COSTS

Unit costs are the estimated costs of serving average-usage customers within a customer group. These costs are expressed in dollars per kW, dollars per kWh, and dollars per customer (i.e., demand-, energy-, and customer-related costs, respectively). In other words, unit costs represent the revenue a utility must collect to recover the costs of meeting each kW of peak demand (or billed demand if demand ratchets are used), delivering each kWh of energy, and serving each customer.

In CMP's 1977 test year cost-of-service study filed in Docket U. #3325, each group's revenue requirement (i.e., revenue that must be collected to produce the allowed rate of return on rate base for each group) was separated into demand-, energy-, and customer-related revenue components. To derive unit cost, we divided the demand, energy, and customer components of each group's revenue requirements by the group's annual billing demand, total kWh consumption, and annual number of customers, respectively. Because demand ratchets are included in our general service flat rates, we divided the demand component of each group's revenue requirement by the total kW billed to the group during the 1977 test year, instead of by the group's coincident or noncoincident peak demand.

Exhibit 1.c gives the number of customers, kWh, and kW billed in each of CMP's general service customer groups during the 1977 test year. The demand, energy, and customer components of each group's revenue requirement (as established by the PUC in its final order in Docket F.C. #2332) are shown in Exhibit 1.d.

By dividing each component of a group's revenue requirement (Exhibit 1.d) by the appropriate customer, kW, or kWh data (Exhibit 1.c), we arrived at the estimated demand, energy, and customer unit costs as shown in Exhibit 1.e. As we noted earlier, these costs represent the costs of serving a general service customer having the same

Exhibit 1.c

CMP 1977 Test-Year Customer Group Data

Customer Group	Annual Customers	Billed kWh	Billed kW
SGS	317,563[a]	128,115,281	922,479[b]
MGS	140,936[c]	753,415,927	3,507,042
Primary	496	9,489,745	38,289
Secondary	140,440	743,926,182	3,468,753
LGS	6,296[d]	1,351,832,941	3,984,218
Primary	1,966	703,471,052	1,836,846
Secondary	4,330	648,361,889	2,147,372

[a] Excludes 3,721 short-term customer months.

[b] CMP estimate.

[c] Excludes 4,552 short-term customer months.

[d] Excludes 103 short-term customer months.

Exhibit 1.d

Revenue Requirement by Customer Group ($)

Customer Group	Demand-Related Revenue [a]	Energy-Related Revenue [a,b]	Customer-Related Revenue [a,c]	Total Revenue
SGS	4,081,588	254,183	2,436,793	6,772,564
MGS	20,887,462	1,400,197	2,301,723	24,589,382
Primary	194,743	16,911	33,983	245,637
Secondary	20,692,719	1,382,286	2,267,740	24,342,745
LGS	22,850,962	1,655,868	553,568	25,060,398
Primary	9,780,974	844,097	204,039	10,829,110
Secondary	13,069,988	811,771	349,529	14,231,288

SOURCE: CMP 1977 test-year cost-of-service study.

a Revenue requirements based on revenues produced by general service rates approved by PUC in Docket FC # 2332.

b Energy-related revenues exclude revenues produced by fuel for generation charge.

c Revenues from short-term customer charges are excluded.

Exhibit 1.e

Estimated Unit Costs

Customer Group	Unit Demand Costs ($/kW)[a]	Unit Energy Costs (mills/kWh)[a,b]	Unit Monthly Customer Costs ($/customer)[a,c]	Unit Demand and Energy Costs (mills/kWh)[a]
SGS	4.425	1.984	7.67	33.84
MGS	5.956	1.858	16.33	
Primary	5.086	1.782	66.51	
Secondary	5.965	1.858	16.15	
LGS	5.735	1.225	87.92	
Primary	5.326	1.200	103.78	
Secondary	6.086	1.252	80.72	

a Estimated unit costs are based on 1977 test-year billing units.

b Excludes fuel for generation charge.

c Excludes short-term monthly customer charges.

monthly kW billing demand and kWh consumption as the average-usage customer within this particular customer group or subgroup (i.e., primary and secondary distribution voltage levels).

DETERMINATION OF MONTHLY REVENUE REQUIREMENTS

Exhibit 1.f gives the kW, kWh, and kVAR (kilovars or reactive kilovolt-amperes) billed to an average-usage customer in each general service customer group and subgroup. The kW and kWh numbers were derived from the data in Exhibit 1.c. The kVAR data were derived using a formula specified by CMP, i.e., a customer's estimated monthly reactive demand equals his monthly billing demand times 0.61974.

As can be seen from the data in Exhibit 1.f, there is a significant difference in the size of customers within a group as measured by a customer's average monthly kW and kWh usage. For example, in 1977, the monthly kW and kWh billed to the average MGS primary customer are more than three times those billed to the average MGS secondary customer. As we discussed earlier, when customers within a customer group (i.e., subgroups) have very different demand and energy consumption levels, it is difficult to design a three-part rate that efficiently and equitably recovers cost-of-service from all customers within such a group. Rate design formulas (which are discussed in the next section) can be used to help overcome this problem.

To determine how well CMP's proposed flat rates recovered the cost of serving general service customers, we estimated the revenues that should be collected each month from an average-usage customer within each customer group or subgroup designation. Specifically, we multiplied each group's kW and kWh unit costs shown in Exhibit 1.e by the group's monthly kW and kWh consumption shown in Exhibit 1.e. We then added the group's average monthly customer cost to the sum of the kW and kWh monthly revenue requirement. The sum of these revenue components equals the monthly revenue that must be collected from the average-usage customer within each group (see Exhibit 1.g). For example, the monthly

Exhibit 1.f

Monthly kW, kWh, and kVAR Billed to Average-Usage Customers in Each General Service Customer Group

Customer Group	kWh	kW	kVAR[a]
SGS	403	2.90	
MGS	5,346	24.88	
Primary	19,133	77.20	9.24
Secondary	5,297	24.70	2.96
LGS	214,713	633.82	
Primary	357,818	934.31	111.87
Secondary	149,737	495.83	59.38

[a] Monthly kVAR billed to an average-usage MGS or LGS customer equals the amount by which the customer's monthly reactive demand exceeds 50 percent of the average kW billed to him each month. The monthly reactive demand equals 0.61974 times the customer's monthly billing demand.

Exhibit 1.g

Monthly Revenue Recovery for Average-Usage Customers Under Various Flat Rates
($)

Customer Group	Monthly Revenue Requirement Per Customer[a]	Monthly Revenue Recovered Under Various Rates[b]		
		Proposed Rates	Proposed Rates (Revised)	Alternative Rates (RPA)
SGS	21.30	20.86 (TR-1)	22.46 (TR-1A)	21.30 (RPA-1)
MGS				
Primary	493.24	490.27 (TR-2)	531.53 (TR-2A)	495.08 (RPA-2)
Secondary	173.33	172.13 (TR-2)	179.40 (TR-1A)	173.58 (RPA-2)
LGS				
Primary	5,509.30	5,809.42 (TR-3)	5,838.49 (TR-3A)	5,510.69 (RPA-3)
Secondary	3,286.42	3,175.60 (TR-3)	2,952.25 (TR-3A)	3,287.21 (RPA-3)

a Revenues to be recovered through the fuel-for-generation charge are excluded.

b All revenues exclude the average monthly fuel-for-generation charge of \$0.0096 per kWh. Revenues recovered include a 4-percent reduction in demand and energy charges for customers receiving service at primary voltage levels, plus a reactive demand charge for MGS and LGS customers equal to \$0.33 per kVAR of reactive demand in excess of 50 percent of the average monthly billing demand. Estimated kVAR of reactive demand per customer equals 0.61974 times the customer's monthly kW billing demand.

revenue requirement for an SGS customer equals $7.67 plus the sum of 403 kWh times 1.984 mills per kWh and 2.90 kW times $4.425 per kW.

Next, we compared the monthly revenue requirement per customer to the revenue that would be collected from the customer under both the February 1 and March 18 rates filed by CMP. As can be seen from these comparisons, which are shown in Exhibit 1.g, the February 1 rates generally come closer to recovering the required revenue from the average-usage customers within each general service group than do the March 18 rates.

Because we felt that rates could be designed to reflect more accurately the cost of service (i.e., produce the required monthly revenue from average-usage customers), we developed the alternative RPA rates shown in Exhibit 1.a. The revenues that would be collected under the RPA rates from average-usage general service customers each month are also shown in Exhibit 1.g. It is evident that the RPA rates would more accurately recover the exact monthly revenue requirement from each average-usage customer than would either CMP's February 1 or March 18 rates.

In the next section, we describe the rate design equations that we used to develop the alternative RPA rates.

DESCRIPTION OF RATE DESIGN EQUATIONS

Our alternative flat rates were designed to accomplish two objectives: first, the rates had to recover the total cost of serving general service customers; second, they had to reflect unit costs as much as possible. Accomplishing both of these objectives for SGS customers was relatively simple. First, we set the monthly customer charge for SGS customers at $7.50, or $0.17 below the estimated unit customer cost. We then divided the remaining monthly revenue requirements by 403 kWh to get the flat kWh charge for Rate RPA-1. The demand charge for demands exceeding 8 kW was set at $5.75 per kW, which is greater than the unit demand cost for SGS customers but less than the unit demand cost for MGS secondary customers who might find it cheaper to be billed under the current GS-1 rate or the alternative RPA-1 rate, if it were implemented (see Exhibit 1.e).

Design of the alternative flat rates for MGS and LGS customers was somewhat more complicated because the rates had to be applicable to customers served at both primary and secondary voltage levels. However, the use of rate design equations simplified the task a great deal. For each customer group (i.e., MGS and LGS customers), we developed a set of simultaneous equations that, when solved, produced the demand and energy charges necessary to meet our two objectives and any other constraints (e.g., making sure that no energy charge in the rate applicable to LGS customers was set below the off-peak energy charge for GST customers).

The equation used to design Rate RPA-2 for MGS customers is shown in Exhibit 1.h. Values for all of the variables in the equation, except CC, x, and y, can be derived from the data in Exhibits 1.f and 1.g. By setting a value for CC approximately equal to the monthly unit customer cost for the particular customer group, we can reduce the problem to solving a set of two equations for two unknown variables, x and y.

For MGS customers, we set the monthly customer charge at $18. Although this charge is slightly higher than the estimated unit customer cost for MGS secondary customers ($16.15 per month), it is substantially below the estimated unit customer cost for MGS primary customers ($66.51 per month). This deviation is a deficiency in the alternative rates we designed, but it is relatively minor and must be accepted if the total cost-of-service for both primary and secondary customers is to be recovered equitably. For example, setting the customer charge at $50 per month would mean that almost 30 percent of the average-usage MSG secondary customer's monthly revenue requirement would be recovered through the customer charge, when, in fact, only about 9 percent of the revenue requirement should be recovered through the customer charge.

Solving the MGS rate design equations for x and y indicated that Rate RPA-2 should include a demand charge of $5.38 per kW of monthly billing demand and an energy charge of 4.1 mills per kWh. We also included a block demand charge of $43.04 for the first 8 kW or less of monthly billing demand to prevent frequent billing crossovers, i.e., SGS customers with fluctuating monthly billing demands finding it sometimes cheaper to be

Exhibit 1.h

Rate Design Equations for MGS Customers

Let:

(1) $MR_p = CC + 0.96x\,(kW_p) + 0.96_y\,(kWh_p) + kVAR_p$

(2) $MR_s = CC + x(kW_s) + y(kWh_s) + kVAR_s$

where:

MR_p	=	monthly revenue requirements for average-usage primary customers
MR_s	=	monthly revenue requirement for average-usage secondary customers
CC	=	monthly customer charge
x	=	demand charge
y	=	energy charge
kW_p	=	average monthly billing demand for primary customers
kW_s	=	average monthly billing demand for secondary customers
kWh_p	=	average monthly kWh usage by primary customers
kWh_s	=	average monthly kWh usage by secondary customers
$kVAR_p$	=	monthly reactive demand charge for average-usage primary customers
$kVAR_s$	=	monthly reactive demand charge for average-usage secondary customers
0.96	=	1 minus 4-percent discount for service at primary voltage.

billed at Rate RPA-2, rather than Rate RPA-1. This block demand charge also conforms to the kW blocking suggested by CMP in Rates TR-2 and TR-2A.

The $5.38 per kW charge is below the average MGS secondary unit demand cost of $5.97 per kW, while the 4.1 mills per kWh is well above the average MGS unit energy cost of 1.86 mills per kWh (see Exhibit 1.e). Although the demand and energy charges will produce the proper monthly revenue recovery from average-usage MGS primary and secondary customers (see Exhibit 1.g), they deviate from the estimated unit costs. Thus, we cannot achieve both of our rate design objectives simultaneously. As we have discussed earlier, deviations from unit costs are necessary when rates are designed for nonhomogeneous customer groups. For example, when flat demand and energy rates are implemented for relatively diverse customer groups, it is necessary to recover some of the demand-related costs through the energy charge. However, deviations of the rates from identifiable demand and energy costs should be minimized to give customers proper price signals. We believe that the deviations of Rates RPA-2 and RPA-3 from unit demand and energy costs have been minimized and that the rates will promote efficient electricity consumption.

To determine demand and energy charges applicable to LGS customers, we used a similar procedure to that used to derive demand and energy charges for Rate RPA-2 (see Exhibit 1.i). The only major difference is that in Rate RPA-3, any energy price charged to LGS customers is either equal to or exceeds the 3.9 mills per kWh off-peak energy charge for GST customers under Rate GST-TD.

Once again, because of the relatively nonhomogeneous nature of the LGS customer group, it became apparent that a portion of the demand-related costs of this group would have to be recovered through an energy charge. Furthermore, because it was impossible to set a demand charge approximating 3.9 mills per kWh without overcharging nearly all LGS customers, we decided to use a two-block energy charge in the LGS rate. The first energy block was set equal to 150,000 kWh, the approximate average monthly kWh consumption of LGS secondary customers (see Exhibit 1.f). We were then able to develop the two LGS rate design equations shown in Exhibit 1.i. As can be seen from the first equation,

Exhibit 1.i

Rate Design Equations for LGS Customers

Let:

(1) $$MR_p = CC + 0.96x\,(kW_p) + 0.96y\,(150{,}000\ kWh) + 0.96\,(207{,}818\ kWh)(\$0.0039/kWh) + kVAR_p$$

(2) $$MR_s = CC + x\,(kW_s) + y(kWh_s) + kVAR_s$$

where:

MR_p = monthly revenue requirement for average-usage primary customers

MR_s = monthly revenue requirement for average-usage secondary customers

CC = monthly customer charge

x = demand charge

y = energy charge for first 150,000 kWh used each month

kW_p = average monthly billing demand for primary customers

kW_s = average monthly billing demand for secondary customers

kWh_p = average monthly kWh usage for primary customers

$kVAR_p$ = monthly reactive demand charge for average-usage primary customers

$kVAR_s$ = monthly reactive demand charge for average-usage secondary customers

0.96 = 1 minus 4-percent discount for service at primary voltage

207,818 kWh = average monthly kWh usage by primary customers minus 150,000 kWh

$0.0039/kWh = off-peak energy charge in Rate GST-TD.

the tail block energy charge of 3.9 mills per kWh is applicable to all kWh consumed in excess of 150,000 kWh. Setting the customer charge (CC) equal to $90 and solving for the flat demand charge (x) and the energy charge for the first 150,000 kWh used each month (y) yielded charges of $3.69 per kW and 9 mills per kWh. Thus, Rate RPA-3 has a flat demand charge of $3.65 per kW and a declining block energy charge: 9 mills per kWh for the first 150,000 kWh used each month, and 3.9 mills per kWh in excess of 150,000 kWh per month.

Because of the nonhomogeneous nature of the LGS customer group and the restriction that the energy charge(s) in the flat rate for LGS customers equal or exceed the off-peak energy charge in CMP's existing optional TOD rate for GST customers, we found it necessary to use a declining block energy charge. The PUC should recognize that, in certain circumstances, declining block energy charges may be justifiable, and, in this case, we believe this rate form is necessary. Had we not included the two-block energy charge, we would have developed a rate that would have resulted in inequitable revenue recovery within this nonhomogeneous customer group.

Although Rate RPA-3 contains a declining block energy charge, it is a significant improvement over CMP's existing and proposed LGS rates (i.e., Rates GS-3, TR-3, and TR-3A), and it represents a good first step in moving toward an overall flattening of CMP's general service rates.

2 TOD RATES

On February 1, 1979, CMP submitted to the PUC optional TOD rates for SGS, MGS, and LGS customers. At this time, CMP indicated that it neither supported nor recommended the implementation of these rates. CMP's proposed TOD rates and the existing non-time-differentiated rates to which the TOD rates correspond are shown in Exhibit 2.a.

In evaluating the TOD rates filed by CMP, we carefully examined (1) the 1977 marginal cost study performed for CMP by NERA, (2) the testimony of J.W. Wilson in Docket F.C. #2332 relating to TOD rates, and (3) the TOD-related working papers CMP submitted in response to the PUC's information request dated February 5, 1979. On the basis of this evaluation, we concluded that the company did not perform a time-differentiated cost study; rather, it relied on peak/off-peak energy cost ratios developed in the NERA marginal cost study to develop cost differentials for application to the company's 1977 embedded cost-of-service study. The result of this exercise was the development of a set of TOD rates that recover the revenue requirements from the SGS, MGS, and LGS customers, but that probably do not reflect the time-differentiated cost of providing service to these customers.

Therefore, we recommend that the PUC not implement CMP's proposed optional TOD rates. Furthermore, we suggest that the PUC request CMP to complete an updated time-differentiated cost study that can be used to design cost-based TOD rates for general service customers. The PUC should work closely with CMP in this effort to ensure that CMP clearly understands the PUC's requirements in terms of the type of TOD cost study that will be acceptable and the types of TOD rates that should be developed from the study.

Because CMP's optional TOD rates are not based on a time-differentiated cost study, we are unable to determine if these rates actually reflect the time-differentiated costs of providing electric service to general service

Exhibit 2.a

General Service TOD Rates for Central Maine Power
($)

Existing Rates		Proposed TOD Rates	
GS-1		**GS1-TD(TR)**	
6.5000	per customer per month	9.5000	per customer per month
3.8500	per kW for all kW in excess of 8 kW of monthly billing demand[a]	4.0000	per kW for all peak billing kW in excess of 8 kW[a]
0.0443	per kWh for first 750 kWh	0.0455	per kWh during peak period
0.0190	per kWh in excess of 750 kWh	0.0128	per kWh during off-peak period
GS-2		**GS2-TD(TR)**	
35.0000	per customer per month	38.0000	per customer per month
2.3000	per kW of monthly billing demand[a]	57.7500	for first 15 kW or less of monthly peak billing demand[a]
0.0190	per kWh for first 5,000 kWh	3.8500	per kW in excess of first 15 kW of monthly peak billing demand[a]
0.0190	per kWh for next 150 kWh per kW of monthly demand	0.0128	per kWh during peak period
0.0147	per kWh for next 150 kWh per kW of monthly billing demand	0.0088	per kWh during off-peak period
0.0116	per kWh for all kWh in excess of above		
GS-3		**GS3-TD(TR)**	
750.0000	per customer per month	750.0000	per customer per month
2.3000	per kW of monthly billing demand[a]	720.0000	for first 200 kW or less of monthly peak billing demand[a]
0.0166	per kWh for first 150 kWh per kW of monthly billing demand	3.6000	per kW in excess of 200 kW of monthly peak billing demand[a]
0.0069	per kWh for next 150 kWh per kW of monthly billing demand	1.1000	per kW for all monthly excess billing demand
0.0060	per kWh in excess of above	0.0075	per kWh during peak period
		0.0035	per kWh during off-peak period

[a] 80-percent, 11-month ratchet.

customers. Moreover, without such a study, we cannot present alternative TOD rates that may be superior to those proposed by CMP. However, we have noted two particular deficiencies in CMP's TOD rate designs that should be rectified.

First, the peak rating period in CMP's general service TOD rates comprises 14 consecutive hours between the weekday hours of 6 a.m. and 10 p.m. These rating periods are similar to those suggested in the marginal cost study performed for CMP by NERA and are identical to the rating periods in Rate GST-TD, which CMP filed in Docket F.C. #2332 and which the PUC approved. In the residential TOD rate, on the other hand, which was also filed in this docket, CMP designated a peak rating period of 8 a.m. to 10 p.m. The PUC ordered CMP to change the peak period for this rate to include only the weekday hours from 8 a.m. to 9 p.m. Although we do not object to the hours CMP selected for the peak and off-peak rating periods, we do feel it is inconsistent to have a residential peak rating period of 8 a.m. to 9 p.m. and a general service peak rating period of 6 a.m. to 10 p.m. As long as the TOD rates are optional, this inconsistency is not a major problem because under the optional rate, information obtained on customers' kW and kWh usage patterns can be considered experimental data. However, if the TOD rates become mandatory, this inconsistency in rating period designation should be corrected.

Second, as we stated in Chapter 1, demand ratchets may be necessary when flat rates are applied to nonhomogeneous customer groups. Demand ratchets are unnecessary, however, in properly designed TOD rates for customers with demand meters capable of measuring demands during daily TOD rating periods. The use of a demand ratchet in a TOD rate implies that demand charges in the rate are too low and results in incorrect demand price signals to the customer. The conservation and efficiency impacts of peak kW charges are diminished when ratchets are used in a TOD rate, because the kW charges must be set below the actual costs of meeting demand during peak periods. Therefore, if the PUC requires CMP to file a new set of TOD rates for general service customers, we recommend that the PUC request CMP to exclude demand ratchets from the rates, unless it can be shown that either CMP or its general service customers would be hurt financially by this exclusion. For example, it may not always be cost-effective to install meters capable of measuring daily peak and off-peak demands.