

APPROACH TO DEVELOPING
ELECTRICITY PRICING AND LOAD
MANAGEMENT PROGRAMS IN MARYLAND

prepared by

Resource Planning Associates, Inc.
44 Brattle Street
Cambridge, Massachusetts 02138

for

The Public Service Commission of Maryland
State Office Building
301 West Preston Street
Baltimore, Maryland 21201

December 1978

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 necessarily reflect the opinions nor the policies of either the NRRI or DOE.

The NRRI appreciates the cooperation of the Public Service Commission of Maryland with the contractor in preparing this study.

FOREWORD

The National Regulatory Research Institute (NRRI) was established at the Ohio State University in 1977 by the National Association of Regulatory Utility Commissioners to provide state regulatory commissions with technical assistance and timely, high level policy research on regulatory issues.

This report is one of a series of publications resulting from on-site technical assistance projects supported by the U. S. Department of Energy (DOE) and directed by the NRRI. The purpose of these technical assistance projects is to provide in-depth studies in specific areas of utility regulation as requested by various state regulatory agencies. A concern of the DOE is for the prudent management and conservation of our national energy resources. Accordingly, it is believed that assistance should be provided to state regulatory agencies in husbanding the energy resources within their state boundaries. Funding availability has limited these efforts such that not all state agencies requesting assistance could be served at first. One criterion for selecting a particular state assistance project was the potential for that project to possibly provide guidance to other regulatory agencies with similar or related problems. It is with that thought in mind that the results of several of the individual state technical assistance projects are being published and made available to others.



Contents

CHAPTER	PAGE	TITLE
INTRODUCTION	i	
CHAPTER 1		TIME-OF-DAY RATES
	1.2	Requirements for Establishing a TOD Pricing Program
	1.15	Evaluation of Utilities' TOD Pricing Programs
CHAPTER 2		SEASONAL ELECTRIC RATES
	2.2	Requirements for Developing Seasonal Rates
	2.4	Evaluation of Utilities' Seasonal Rate Programs
CHAPTER 3		OFF-PEAK DISCOUNTS
	3.5	Requirements of Implicit Off-Peak Discounts
	3.6	Evaluation of Utilities' Responses
CHAPTER 4		AIR-CONDITIONING END-USE TARIFFS
	4.1	Requirements for Developing End-Use Tariffs
	4.2	Evaluation of Utilities' Responses
CHAPTER 5		MARGINAL-COST-BASED PRICING
	5.2	Requirements for Developing Marginal-Cost-Based Rates
	5.5	Evaluation of Utilities' Marginal-Cost-Based Rates

CONTENTS

CHAPTER 6

TIME-OF-DAY USAGE EXPERIMENTS

- 6.3 Requirements for Conducting Load Research Studies
- 6.5 Evaluation of Utilities' Responses

CHAPTER 7

LOAD MANAGEMENT PROGRAMS

- 7.2 Requirements for Developing Load Management Programs
- 7.5 Evaluation of Utilities' Proposed and Existing Load Management Programs

Exhibits

CHAPTER	NO.	TITLE
CHAPTER 1	1.a	Distribution of Total System Costs
	1.b	BG&E Summary of TOD Rates Based on Accounting Costs
	1.c	Unit Demand Costs and Demand Charges for BG&E's Schedule T
	1.d	Service Classification "R-PLP" (Residential - Peak Load Pricing Service)
CHAPTER 2	2.a	Residential Service - Electric (Schedule R)
	2.b	General Service - Electric (Schedule G)
	2.c	Service at 13,200 Volts and Over (Schedule T)
	2.d	Service Classification "R" (Residential Service)
	2.e	Service Classification "GS-S" (General Service - Secondary)
	2.f	Service Classification "GS-P" (General Service - Primary)
CHAPTER 3	3.a	Electric -- Baltimore Gas and Electric Company
CHAPTER 5	5.a	BG&E Summary of Marginal Cost Rates Maintaining the Ratio of Marginal Costs Between Schedules
	5.b	BG&E Summary of Marginal Cost Rates Based on Case No. 7070 Revenue Allocation
	5.c	Delmarva Adjusted Marginal Cost Rates



Introduction

As part of its economic regulatory responsibilities, the Public Service Commission (PSC) of Maryland faces the task of developing a regulatory policy aimed at stemming rising electricity prices. The most effective means of halting such price rises is to increase the efficiency of the production and consumption of electricity. Consequently, the Maryland PSC is investigating pricing policy changes and load management options that could lead to an increase in production and consumption efficiency.

In this effort, the PSC issued an order requiring all utilities with gross annual revenues exceeding \$25,000,000 to file a report, on or before January 1, 1978, containing the following:*

1. Cost studies and rate structures based on marginal costs
2. Plans for implementing time-of-day (TOD) rates on a voluntary basis for all residential customers and on a mandatory basis for all large commercial and industrial customers
3. Plans for undertaking load research studies of 200 large residential customers as a basis for developing TOD rates
4. Feasibility studies of applying end-use tariffs for air conditioners to large residential customers, office buildings, and shopping centers
5. Current and proposed seasonal rate differentials
6. Feasibility studies of offering off-peak discounts to large commercial and industrial customers
7. Current and proposed load management activities designed to reduce future generating capacity requirements.

* Maryland, PSC, Case No. 6808, Order No. 62568, "Investigation of Electric Utility Rate Structures."

To assist the Maryland PSC in analyzing the utilities' responses to Order No. 62568 and selecting appropriate pricing policies and load management programs, the National Regulatory Research Institute (NRRI) retained Resource Planning Associates, Inc. (RPA).^{*} In this effort, RPA first evaluated the various pricing options (Items 1, 2, 4, 5, and 6 listed above), the load research program (Item 3), and the load management activities (Item 7) addressed in Order No. 62568 to determine their effectiveness in meeting the PSC's goal of increased efficiency. We then recommended a broad pricing and load management program to the PSC. This broad program provides the necessary framework for issuing more specific directives to the utilities. Finally, we evaluated the utilities' responses to the items given in Order No. 62568 and made specific recommendations regarding the utilities' existing and proposed pricing and load management programs.

On the basis of our assessment of various time-of-use (TOU) rates, end-use tariffs, load research programs, and load management options, we recommend that the PSC adopt a broad pricing and load management program that requires the utilities operating in Maryland to:

1. Develop and implement rates that reflect the time-related cost differences of providing electric service (i.e., TOU rates). However, because certain forms of TOU rates are more effective than others in terms of increasing efficiency, we recommend that the PSC direct the utilities to institute the following rate hierarchy:

- Implement TOD rates for all customers who either already have the required TOU metering (e.g., magnetic tape meters) or are willing to pay the additional costs of such metering.
- Offer seasonal rates to those customer groups for whom TOD rates are not currently practical because of insufficient metering.

^{*} In this study, we analyzed the responses of two utilities: Baltimore Gas and Electric Company (BG&E) and Delmarva Power & Light Company of Maryland (Delmarva). In total, five utilities responded to the PSC's order.

-
- Continue to offer implicit off-peak discounts (i.e., billing demand is less than measured demand during off-peak periods) to customers with the required metering (e.g., magnetic tape meters) and offer such discounts to smaller customers willing to pay the additional costs of metering. However, off-peak discounts should only be offered where seasonal rates are used.
 - 2. Eliminate end-use tariffs for air conditioners from further consideration, as the potential benefits of such tariffs (e.g., reduced consumption and demands during the summer peak period) can be achieved as effectively and at less cost by the use of TOU rates (e.g., seasonal rate differentials).
 - 3. Base TOD and seasonal rates on accounting costs rather than on marginal costs to facilitate immediate implementation. Although RPA supports rates based on marginal costs (because marginal costs more accurately reflect the true costs of providing the service and the value the consumer places on that service), we recognize that to develop and implement such rates will require considerable additional study and time. Therefore, in the short term, we support the development of rates based on accounting costs. However, the PSC should encourage the utilities to submit cost-of-service studies based on marginal costs in anticipation of future changes in rate-making practices.
 - 4. Collect load research data for use in future, more comprehensive pricing and load management programs.
 - 5. Undertake inexpensive indirect load management programs (e.g., encourage residential customers to install insulation). At the same time, the utilities should evaluate the feasibility of implementing more expensive indirect and direct load management programs (e.g., energy-storage and direct load control systems).

Our utility-specific recommendations regarding TOU pricing, end-use tariffs, marginal cost studies, TOU experiments (load research), and load management activities are detailed in each chapter. The adequacy of the utilities' responses varied by utility and by item.

Generally, both utilities could improve their existing and planned programs in the areas addressed in Order No. 62568. However, before the PSC requires the utilities to undertake specific actions regarding their individual programs, it should adopt a broad pricing and load management program, either the program described above or some alternative. Specific PSC requests and directives issued to the utilities can then focus on concrete actions that meet the efficiency goals of the PSC's broader program.

We present our evaluations and recommendations in seven chapters, corresponding to the seven items comprising Order No. 62568. We have reordered these items, first discussing those related to pricing, then those related to load research and load management:

- Chapter 1: Time-of-Day Rates
- Chapter 2: Seasonal Electric Rates
- Chapter 3: Off-Peak Discounts
- Chapter 4: Air-Conditioning End-Use Tariffs
- Chapter 5: Marginal-Cost-Based Pricing
- Chapter 6: Time-of-Day Usage Experiments
- Chapter 7: Load Management Programs.

1

TIME-OF-DAY RATES

As part of its investigation of electricity rate options, the Maryland PSC ordered "that each electricity company, with gross annual revenues exceeding \$25,000,000, shall file plans with the Commission, on or before January 1, 1978, which provide for time-of-day price differentials and time-of-day metering on a voluntary basis for all residential customers, and on a mandatory basis for all large commercial and industrial customers."*

TOD rates reflect the different costs of providing electricity during different times of the day, and, as such, they are a form of TOU pricing.** TOU metering (e.g., magnetic tape metering) is required to implement TOD rates.

RPA recommends that the PSC direct the utilities in Maryland to implement mandatory TOD rates for all customers with TOU metering and to offer voluntary, optional, TOD rates to all customers willing to pay the additional metering costs. TOD rates may be based on either marginal or accounting costs.†

In the following sections, we describe the requirements for establishing a TOD pricing program and present our evaluations of the utilities' responses to the PSC order.

* Maryland PSC, Case No. 6808, Order No. 62568, p. 3.

** For a discussion of other forms of TOU pricing (i.e., seasonal rates and off-peak discounts), see Chapters 2 and 3 of this report.

† To expedite implementation, we suggest that TOD rates be based on accounting costs at this time. As knowledge on marginal-cost-based rates increases and the utilities complete further studies, TOD rates should be adjusted to reflect marginal costs more fully.

REQUIREMENTS FOR ESTABLISHING
A TOD PRICING PROGRAM

TOD pricing is a means of promoting the efficient consumption and production of electric energy. Because the costs of producing electricity during peak periods exceed the costs during off-peak periods, the prices charged for consumption during peak periods should be higher than those charged for consumption during off-peak periods. When peak and off-peak prices are the same, consumers are encouraged to use too much electricity during peak periods and too little during off-peak periods. In this manner, consumption inefficiency is promoted, resulting in production inefficiency, because the generation capacity added to meet increases in demand is not used during much of the year.

If consumers respond to TOD price differentials by either shifting loads to, or creating new loads in, off-peak periods, both producers and consumers of electricity will benefit. Benefits to producers include reductions in production costs and potential reductions in future requirements for generation capacity; benefits to consumers include reductions in electricity bills for consumers whose use occurs primarily during off-peak periods and a slowing in the growth of electricity prices to all consumers because of a reduction in future generation capacity requirements.

Because these potential benefits will be reduced by the additional metering, billing, and administrative costs associated with the implementation of TOD pricing, it is necessary to determine if the benefits would exceed costs before requiring TOD rates for a particular customer group. The greatest costs associated with TOD rates are the costs of the relatively sophisticated and expensive metering.

For customer groups not requiring the installation of additional metering, costs of implementing TOD rates are minimal; mandatory TOD rates should be provided for those groups. In general, these groups consist of large industrial and commercial customers with magnetic tape recording meters. To facilitate the implementation of mandatory TOD rates for customers who already have

TOU metering (e.g., BG&E's Schedule T customers and Delmarva's customers billed under the company's proposed Rate GS-P), the PSC should require the utilities to design TOD rates such that the same level of revenue would be collected from this group of customers under either TOD or non-TOD rates.* This requirement should ease the industrial customers' concerns that TOD rates will be used to shift part of the residential revenue burden to the industrial customer group.

For customers requiring additional metering (residential and small general service customers), the costs and benefits of TOD rates must be examined more closely. One means of assessing the costs and benefits is to offer TOD rates on a voluntary basis to any customer willing to pay the additional metering costs. Offering voluntary TOD rates enables a utility to gain experience in handling unconventional rate forms and to collect information on the usage patterns of customers for whom TOD rates are cost effective (i.e., customers for whom the benefits exceed the additional metering costs). TOD rates offered on an optional basis also enable a utility to avoid the problems associated with implementing mandatory TOD rates for all customer groups. Such problems include the purchase and installation of new meters and complex revisions in computer billing programs. Most importantly, optional TOD rates allow utilities to learn about the potential effects of TOD rates without forcing sudden changes in life-styles or monthly electricity bills.

If voluntary TOD rates are offered, they will be most attractive to customers who can reduce their annual electricity costs with little or no alteration in their consumption patterns (i.e., customers whose greatest consumption already occurs during the off-peak hours). Consequently, adoption of TOD rates by these customers will not affect the utility's peak load. Therefore, the voluntary approach to TOD pricing should only be considered a first phase in the implementation of TOD rates.

* This assumes that the existing allocation of revenue requirements to customer groups is appropriate.

The voluntary approach to TOD pricing will lead to customer adoption of TOD rates over time. Because a utility's revenues may decrease by offering voluntary TOD rates, the utility may increase non-TOD rates in order to earn the level of return allowed by the PSC. For example, assume mandatory TOD and conventional non-TOD rates for large commercial and industrial customers generated the same level of revenue. In this situation, offering optional TOD rates to residential customers could reduce the utility's revenues without reducing the cost of producing electricity. If the PSC allowed a utility to raise residential non-TOD rates to recover this revenue deficiency, more customers would find they could reduce their annual electricity bills by selecting the optional TOD rates. This process would continue until an equilibrium was reached, i.e., all customers who could achieve a reduction in their annual electricity bills by selecting TOD rates will have done so. Thus, a gradual implementation of TOD rates on an optional, voluntary basis could achieve the same result as a mandatory implementation plan without forcing sudden changes in life-styles.

Once a plan for implementing TOD pricing has been developed, it is necessary to design the specific TOD rates for selected customer groups. In general, the steps required to develop TOD rates are:

- Select a cost methodology
- Select a test period
- Select rating periods
- Estimate demand-, energy-, and customer-related costs
- Allocate costs to rating periods
- Allocate costs to customer groups
- Develop unit costs.

Each step is described in the following subsections.

Select a Cost Methodology

Either of two types of cost methodologies may be used: those based on marginal costs, or those based on accounting costs.* The PSC did not specify which type the utilities should use to develop mandatory and voluntary TOD rates. Although the marginal cost methodology is the subject of Chapter 5 of this report, we discuss both marginal and accounting cost methodologies in this chapter.

The accounting cost methodology is an extension of conventional fully allocated cost methodologies used by utilities and regulatory bodies.** In addition to assigning costs by function (e.g., generation, transmission, and distribution) and classifying costs within each function (e.g., demand, energy, and customer), the TOD accounting cost methodology requires selecting rating periods and allocating costs to rating periods and customer groups.

Although there is no universally accepted method for developing TOD rates using either marginal or accounting costs, utility ratemakers generally prefer basing TOD rates on accounting costs, rather than on marginal costs. The primary reasons given for this preference are excess revenue problems associated with marginal cost rates and unresolved issues regarding how to measure marginal costs. However, there are also unresolved issues concerning accounting cost methodologies.† For example, there are no universally accepted methods for allocating distribution costs and developing factors for allocating power supply costs.

* Several variations of the marginal and accounting cost methodologies are described in Rate Design and Load Control: Issues and Directions, Electric Power Research Institute, November 1977.

** For descriptions and analyses of these methodologies, see J.J. Doran et al., Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, Washington, D.C. 1973.

† Electric Power Research Institute, November 1977, p. 15.

Select a Test Period

After selecting a cost methodology, the utility must select a test period for determining the costs to be allocated to rating periods and customer groups and the revenue required to produce an allowed rate of return.

To reflect conditions expected to exist during the period when TOD rates are in effect, a future test year should be used when developing either accounting- or marginal-cost-based rates. If accounting costs are used to develop TOD rates, both cost allocations and revenue requirements should be determined. Because marginal costs are estimated for a specific point in the future, in this case, the test period is used to establish the revenue requirement to be recovered by the rate and the billing determinants (i.e., number of bills, kilowatt-hour [kWh] sales, and kilowatt [kW] demands) used to set the rates.

Select Rating Periods

Selecting rating periods (i.e., time periods during which different electricity rates are in effect) is a critical step when developing time-related rates. A basic assumption underlying TOU rates is that the cost of providing electric service varies hourly, daily, and seasonally. For example, the cost of providing electric service is generally higher during daylight or early evening hours, on weekdays, and during the season with the higher peak. Thus, the rating periods selected should correspond to the time-related cost differences of providing electric service.

The number and length of rating periods are constrained by several factors. First, meters capable of measuring consumption during selected rating periods must be available at a reasonable cost. Second, the number of rating periods should be kept to a minimum to enable customers to understand and react to the TOD pricing structure. Third, the length of a peak rating period should be long enough to prevent new peaks from occurring during the hours immediately preceding and following the period, yet short enough to enable customers to respond to TOD rates by shifting usage to off-peak periods.

In spite of these constraints, several methods are available for selecting rating periods.* However, regulators and utilities have not yet identified a single method as being demonstrably superior to other methods.** RPA believes a reasonable method for selecting rating periods is statistical analysis of monthly, daily, and hourly load data and hourly production cost data. Analysis of variance (ANOVA) tests can be used to group months, days, and hours into rating periods exhibiting statistically similar load and production cost characteristics.† The ANOVA tests are designed such that the variances in monthly, seasonal, and hourly loads and hourly production costs within a rating period are minimized and the variances between rating periods are maximized.

Estimate Demand-, Energy-, and Customer-Related Costs

After rating periods are selected, demand-, energy-, and customer-related costs must be estimated. Demand-related costs are the costs of generation capacity and transmission equipment required to meet electric loads. Energy-related costs are the fuel and other variable costs incurred in kWh production. Customer-related costs include distribution costs incurred in meeting minimum customer loads and general expenses, such as the costs of reading meters and billing customers.

When accounting costs are used to develop TOD rates, demand-, energy-, and customer-related costs are estimated using traditional cost-of-service techniques, as described in the cost allocation manual published by

* Electric Power Research Institute, November 1977, pp. 27-29, 49-50.

** Electric Power Research Institute, November 1977, p. 50.

† For a description of Long Island Lighting Company's use of this method, see Richard W. Bossert, "Defining Time-of-Use Periods for Electric Rates," Public Utilities Fortnightly, Vol. 99, No. 7 (March 31, 1977): pp. 19-24.

the National Association of Regulatory Utility Commissioners.* These techniques require grouping all costs by function (i.e., generation, transmission, and distribution) and, within each function, classifying costs as demand-, energy-, and customer-related costs (see Exhibit 1.a). Some proponents of the use of accounting costs advocate the further disaggregation of demand-related generation costs into baseload, intermediate, and peaking capacity categories.**

When marginal costs are used to develop TOD rates, it is necessary to estimate marginal energy, generating capacity, transmission, and distribution costs. Marginal energy costs are the incremental fuel and operation and maintenance expenses associated with meeting increases in demand. Marginal generating capacity costs are equivalent to the cost of the least expensive generating unit added to meet an increment in demand during peak periods.† Marginal transmission costs are the incremental costs per kW of system peak demand resulting from an optimal expansion of the transmission system to meet load growth and the system's reliability criteria. Marginal distribution costs include demand and customer components and may include some energy-related costs when excess distribution capacity is installed to reduce energy losses and to minimize future replacement costs.

Allocate Costs to Rating Periods

After demand-, energy-, and customer-related costs have been estimated, the demand and energy costs are allocated to rating periods. Customer costs derived from accounting data are allocated directly to appropriate customer groups and not to rating periods (see the next subsection).

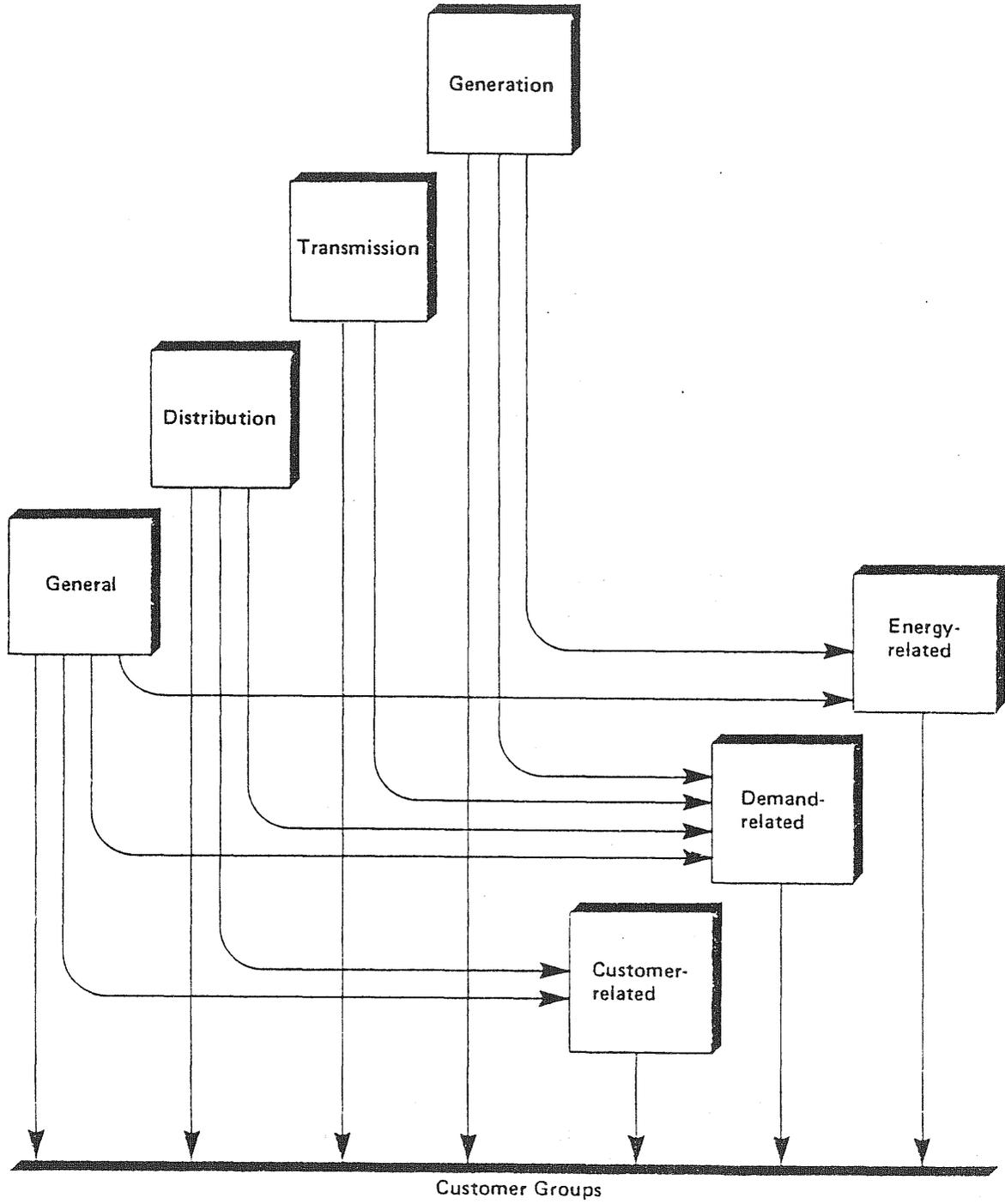
* J.J. Doran et al., 1973.

** Electric Power Research Institute, November 1977, p. 29.

† The size and type of unit added depends on such factors as the length of the peak period and the economic costs of alternative types of capacity. The marginal unit added will not always be a peaking turbine.

Exhibit 1.a

Distribution of Total System Costs



Marginal customer costs are not allocated to rating periods or customer groups. Instead, the long-term unit cost of serving a customer at different voltage levels is estimated and multiplied by the economic carrying charge to derive an annual unit cost. This unit customer cost is then adjusted to include other customer-related expenses (e.g., sales, administrative and general, customer accounts, and plant-related operation and maintenance expenses) and a revenue requirement for working capital. (These expenses and the revenue requirement vary by customer group.) Thus, the annual marginal unit cost for each customer group is estimated independently instead of estimating aggregate customer costs that must then be allocated to customer groups.

The three principal methods used to allocate demand costs to rating periods are: the loss of load probability (LOLP) method; the base-intermediate-peak (BIP) method; and the peak responsibility method.

In the LOLP method, demand-related costs for generation, transmission, and distribution are allocated to rating periods using capacity cost allocation factors. These factors are derived by dividing the rating period LOLP (i.e., the probability that demand exceeds a utility's capability to meet that demand) by the annual LOLP. The capacity cost allocation factors are divided by the ratio of the seasonal average peak demand to the system peak demand and then multiplied by the demand-related capacity costs per kW of system peak demand adjusted for losses. The resulting number is an estimate of the marginal demand-related unit cost (in dollars per kW) of generation, transmission, and distribution capacity for each seasonal rating period and each voltage delivery level.*

The BIP method of allocating demand-related generation costs to rating periods requires separating capacity into baseload, intermediate (e.g., cycling), and peaking units. For example, assume three rating periods were

* For a complete description of the LOLP capacity cost allocation method, see National Economic Research Associates, Inc., How to Quantify Marginal Costs: Topic 4, prepared for the Electric Utility Rate Design Study, March 10, 1977, pp. 124-129.

selected: a peak period, an intermediate or secondary period, and an off-peak period. In the BIP method, one-third of all baseload capacity costs would be allocated to each rating period, the intermediate capacity costs would be allocated equally to the peak and intermediate periods, and all peaking capacity costs would be allocated to the peak period.

In the peak responsibility method, capacity costs are allocated to rating periods according to coincident or noncoincident peak demands or to the probability that the system load during each rating period will exceed a specified level. This latter variant of the peak responsibility method is called the probability of contribution to peak (PCP).

Because we prefer the method selected to be related to the intensity of demand in each rating period, we recommend the LOLP and PCP methods over the BIP method. In the LOLP and PCP methods, relatively few or no demand-related capacity costs are allocated to the off-peak period; in the BIP method, up to one-third of all baseload generation capacity costs may be assigned to the off-peak period. Advocates of the BIP method claim that failure to allocate some capacity costs to the off-peak period results in a "free ride" for off-peak consumers.* However, there is no economic justification for assigning up to one-third of baseload capacity costs to the off-peak period because off-peak demands affect the types of capacity included in an optimal capacity mix, not the amount of capacity.**

* Task Force 4 of the Electric Utility Rate Design Study reported that use of the BIP method can produce illogical estimates of the costs to be recovered from customers. See Task Force No. 4., Comments on Two Costing Approaches for Time-Differentiated Rates, prepared for the Electric Utility Rate Design Study, March 8, 1977, pp. 133-141.

** Several economists have recently demonstrated that under certain load and operating conditions, off-peak consumers should bear some portion of generation capacity costs. For example, see J.C. Panzar, "A Neo-classical Approach to Peak Load Pricing," Bell Journal of Economics, Vol. 7, No. 2 (Autumn 1976): pp. 521-530; and J.T. Wenders, "Peak Load Pricing in the Electric Utility Industry," Bell Journal of Economics, Vol. 7, No. 1 (Spring 1976): pp. 232-241.

The amount of capacity is determined primarily by peak demands. For example, to meet identical increases in peak and off-peak loads (i.e., the load duration curve increases by an amount equal to the specified demand increment), a utility may add peaking units, intermediate units, or baseload units. Assume that a utility chooses to meet the peak and off-peak increases by adding a baseload generating unit with high capital and low operating costs. The baseload unit will be selected over a combination of intermediate and peaking units only if the difference between the higher capital cost of the baseload unit relative to other types of capacity is equal to, or less than, the fuel cost savings resulting from adding the baseload unit. The relatively higher capacity costs of the added baseload unit (i.e., relative to other types of generating capacity), should be offset by the fuel cost savings resulting from not having to operate peaking units (to meet the peak period increase) and older, less efficient steam units (to meet the off-peak increase). Thus, if the higher capital costs of this added baseload unit were offset by fuel cost savings, a TOD off-peak rate should not reflect any baseload capacity costs. If fuel cost savings did not offset the higher capital costs of the baseload unit, off-peak charges should reflect only the difference between the fuel cost savings and the higher baseload capacity costs. Therefore, assigning baseload capacity costs to the off-peak rating period without adjusting for fuel cost savings, as is done when the BIP method is used, results in the development of TOD rates that undercharge peak period consumers and overcharge off-peak consumers.

Energy-related costs estimated using accounting data are allocated according to kWh sales and adjusted for losses in each rating period. Marginal energy costs are estimated for each rating period, and, thus, no allocation to rating periods is required.

Allocate Costs to Customer Groups

The next step in developing TOD rates is to allocate costs to customer groups or classes.

When accounting costs are used, the allocation method requires five substeps:

1. Identify customer groups
2. Allocate demand-related generation and transmission costs
3. Allocate demand-related distribution costs
4. Allocate energy-related costs
5. Allocate customer-related costs.

Identify customer groups. We recommend that the PSC require utilities to use broad customer categories (e.g., residential, commercial, and industrial classes) in the initial stages of implementing TOD rates. The problem with using broad customer categories is that the TOD rates established for a customer group may not be equitable in terms of cost responsibility for all members within that group. Thus, the PSC should examine the issue of more narrowly defining customer groups.

Allocate demand-related generation and transmission costs. Many different methods may be used to allocate these costs to customer groups.* We recommend some form of the peak responsibility method that relates the cost of meeting peak demands to the coincident peak demands of each customer group.

Allocate demand-related distribution costs. For this substep, we recommend using the noncoincident peak (NCP) responsibility method. The distribution system is built and maintained to meet maximum customer demands whenever they occur. Therefore, it is most appropriate to allocate demand-related distribution costs based on maximum individual group demands (i.e., NCPs). The noncoincident demands used should be estimated at the distribution level (e.g., primary and secondary distribution voltage levels) at which a customer group receives service, and adjusted for demand losses.

* National Economic Research Associates, Inc., identified 29 methods in An Overview of Regulated Ratemaking in the United States, Topic 1.1, Appendix A, prepared for the Electric Utility Rate Design Study, February 2, 1977.

Allocate energy-related costs. We recommend that energy-related costs be allocated to customer groups on the basis of energy (kWh) consumed and adjusted for line losses. For example, the ratio of residential kWh consumption during the peak period (adjusted for line losses) to total kWh generated during that period can be used to allocate energy-related peak costs to the residential customer group. This procedure relies on readily available and reliable data and, as such, involves little subjective analysis.

Allocate customer-related costs. The allocation of customer-related costs should be based on the number of customers within each group relative to the total number of customers served by a utility. Customer differences within and among groups (e.g., location, size, and type of distribution equipment required for service) should also be accounted for. If distribution costs are identified by subfunction (e.g., primary and secondary distribution voltage levels), the allocation of the customer-related portion of costs within each subfunction should be based on the number of customers served at each voltage level.

When marginal costs are used to develop TOD rates, cost allocations to customer groups are not required, because annual marginal unit customer costs are estimated for each customer group, rather than as an aggregate figure.

Marginal energy costs also are not allocated to customer groups, because these costs are estimated for each rating period and adjusted for losses occurring at each voltage level. We have already discussed the allocation of marginal demand-related capacity costs using the LOLP and capacity cost allocation factor. These costs, which are estimated for each service voltage level, should be recovered through rates applicable to customers at particular service voltage levels.

Develop Unit Costs

Utilizing the data developed in the above steps, unit costs (i.e., dollars per kW, per kWh, and per customer per month) are developed by rating period for each customer group. These unit costs provide the basis for designing three-part TOD rates (i.e., rates with customer, demand, and energy charges).

EVALUATION OF UTILITIES'
TOD PRICING PROGRAMS

Both BG&E and Delmarva need to improve their TOD pricing programs. In the following subsections, we describe the utilities' responses to the PSC's order and recommend ways of improving their programs.

Baltimore Gas and
Electric Company

In response to the PSC's order, BG&E submitted TOD rates based on accounting costs for residential (Schedule R), commercial (Schedule G), and industrial (Schedule T) customers (see Exhibit 1.b). The rates were designed to produce a 9.11-percent rate of return from each of the three major customer groups. The cost-of-service study used to develop the rates was based on a 12-month test period ending September 30, 1976 and was subsequently modified to reflect the 9.11-percent allowable rate of return granted by the PSC in Case No. 7070. Allocation factors and unit costs were developed from 1977 data on number of customers, sales, and loads.

On the basis of our analyses of the accounting cost methodology, the rating periods, and the billing determinants used by BG&E, we recommend that the PSC require BG&E to file new residential, commercial, and industrial TOD rates that more accurately reflect the time-related cost differences of providing electric service. In the course of our analysis, we identified a number of deficiencies in the methods used by BG&E to develop the TOD rates. These deficiencies are discussed in the following paragraphs.

BG&E's use of the BIP method to allocate power supply demand costs (i.e., generation and transmission costs) to rating periods is a major deficiency. When applying the BIP method, BG&E allocated power supply costs as follows: 43.45 percent to the summer peak period, 29.47 percent to the winter peak period, and 27.08 percent to the off-peak period. As stated earlier in this chapter, we do not support the use of the BIP method, because it requires an arbitrary allocation of demand costs and results in off-peak consumers being overcharged and peak customers, undercharged.

Exhibit 1.b

BG&E

Summary of TOD Rates
Based on Accounting Costs

	Schedule R	Schedule G		Schedule T
		60 kW Demand and Under	Over 60 kW Demand	
Customer charge (\$/bill)	7.260	11.040	64.430	253.000
Demand charge (\$/kW)				
Peak				
–Summer	–	–	10.310	7.480
–Winter	–	–	5.380	2.980
Off-peak				
–Summer	–	–	10.310	3.080
–Winter	–	–	5.380	3.080
Energy charge (¢/kWh)				
Peak				
–Summer	8.589	5.507	0.692	0.661
–Winter	4.575	2.855	0.702	0.673
Off-peak	2.602	1.993	0.341	0.319

A second major deficiency of BG&E's TOD rates is the failure of the proposed rates to reflect the time-differentiated demand costs estimated by the company. For example, BG&E estimates of unit demand costs for Schedule T are \$39.83, \$28.69, and \$26.77 for the summer peak, winter peak, and off-peak periods, respectively (see Exhibit 1.c).^{*} However, after translating these unit demand costs into demand charges, the resulting charges are \$7.48, \$2.98, and \$3.08 per kW per month for the summer peak, winter peak, and off-peak periods, respectively. Thus, although BG&E's unit cost analysis showed that winter peak unit demand costs are higher than off-peak unit demand costs, in Schedule T, the off-peak demand charge is higher than the winter peak demand charge. These illogical demand charges are created by BG&E's allocation of power supply costs to the off-peak period (as described above) and the company's assumption that customers will not respond to TOD rates by shifting some peak load to the off-peak period.

Also of major concern is the failure of BG&E's TOD rate for Schedule G customers with demands exceeding 60 kW to promote the PSC's goal of production and consumption efficiency. The proposed TOD rate for these customers includes identical seasonal demand charges for both peak and off-peak periods. BG&E should develop a rate that includes peak and off-peak demand charges for this customer group, and, if these customers have insufficient metering, include the additional metering costs in the customer charge.

Of lesser importance, yet still constituting a deficiency, is BG&E's method of selecting peak periods. BG&E examined daily load curves, and, in general, it assigned to the peak period all hours during which loads were equal to, or greater than, 80 percent of the daily peak load. BG&E selected daily rating periods and seasonal rating periods (summer billing months [i.e., June-September] and winter billing months [i.e., October-May]). The daily peak period includes all

* Unit demand costs are derived by dividing demand-related cost estimates by kW demands.

Exhibit 1.c

**Unit Demand Costs and
Demand Charges for BG&E's Schedule T***

Rating Period	Unit Demand Cost (\$/kW)	Demand Charge (\$/kW/month)
Peak		
Summer	39.83	7.48
Winter	28.69	2.98
Off-peak	26.77	3.08

*Data taken from Exhibit G.2-5 in BG&E's response to PSC Order No. 62568.

weekday hours between 8:00 a.m. and 11:00 p.m. All other hours constitute the daily off-peak period. The length of the daily peak period (15 hours) will prevent most consumers from shifting loads to off-peak periods.

Analysis of load curves is only a preliminary step in establishing rating periods. To verify the validity of the rating periods, BG&E should also undertake statistical analyses of hourly loads (such as ANOVA tests) and the relationship between these loads and production costs during each hour of the day.

Another more minor deficiency is BG&E's failure to develop a three-part TOD rate for large residential customers. Although we recognize that BG&E developed its TOD rates assuming that these customers would not have meters capable of measuring peak kW demands (TOU meters), we believe that BG&E should develop three-part TOD rates for these customers and include the additional metering costs in the customer charge. Three-part TOD rates, which explicitly recognize the various types of costs incurred by a utility in providing electric service (i.e., demand-, energy-, and customer-related costs), would provide customers with greater incentives to consume electricity efficiently than would two-part TOD rates that do not explicitly recognize demand costs.

BG&E's estimates of revenues produced by TOD rates are also questionable, as they are based on assumptions of a 5-percent reduction in kWh sales to Schedules R, G, and T customers and a 5-percent reduction in billed kW to Schedule T customers during the seasonal peak rating periods. In other words, BG&E assumed that there would be an absolute decrease in peak consumption without any shifts to the off-peak period. Although we believe that customers will respond to TOD rates by decreasing consumption during peak periods, we also believe that some peak period consumption will be shifted to the off-peak period.

On the basis of its assumptions, BG&E increased peak prices to account for the assumed 5-percent decrease in consumption but did not decrease off-peak prices, as would be necessary if consumption increased in the off-peak period. Moreover, in the TOD rate for Schedule G customers with demands exceeding 60 kW, BG&E assumed

the 5-percent decrease in kWh consumed during peak periods but did not assume a decrease in kW demand during the peak as was assumed for Schedule T. BG&E should explain this inconsistency.

In addition to addressing the deficiencies noted above, BG&E should demonstrate that it has properly allocated energy-related costs to rating periods. BG&E's allocation of energy costs and net Baltimore Contract Load kWh sales results in kWh rates during the winter peak that exceed kWh rates during the summer peak for Schedule T customers and Schedule G customers with demands exceeding 60 kW. BG&E should verify that these results actually reflect typical energy costs and do not result from abnormal operating conditions during the test period.

Finally, BG&E should explain how fuel adjustment charges (FAC) will be applied to the TOD rates. If BG&E and the PSC plan to use price and consumption data to derive reliable estimates of the effects of TOD rates on electricity usage, FAC should be applied in a manner such that they do not distort the ratio of peak-to-off-peak prices.

Delmarva Power & Light
Company of Maryland

Delmarva did not file TOD rates in response to PSC Order No. 62568. However, the company did indicate that it planned to file a voluntary residential TOD rate and a mandatory TOD rate for large commercial and industrial customers with magnetic tape meters by June 30, 1978. Upon examining the rates subsequently filed by Delmarva in Case No. 7174, we found that Delmarva had only filed a voluntary residential TOD rate, Rate R-PLP (see Exhibit 1.d). Therefore, we recommend that the PSC require Delmarva to comply with Order No. 62568 by immediately filing mandatory TOD rates applicable to commercial and industrial customers.

Delmarva's residential rate (Rate R-PLP) appears to be well designed. However, prior to accepting Rate R-PLP, the PSC should establish a test period and revenue requirement for the residential customer class in Maryland and then determine the appropriate customer, demand, and energy charges to be included in the rate.

Delmarva Power & Light Company of Maryland

SERVICE CLASSIFICATION "R-PLP"

RESIDENTIAL - PEAK LOAD PRICING SERVICE

A. Availability

This rate is available for household and other related uses in a single private dwelling or dwelling unit, to those customers:

1. Whose present facilities will accommodate a multi-register socket-type meter and where sufficient space exists for the installation of the meter, or
2. Who will make the necessary modifications, at their own expense, to permit the installation of the multi-register socket-type meter.

B. Contract Term

Written contracts will be required for all Customers receiving service under this service classification. The contract will be for an initial term of one (1) year with automatic month-to-month extensions until terminated.

C. Monthly Rate

	<u>Billing Months</u> <u>June through September</u>	<u>Billing Months</u> <u>October through May</u>
<u>Customer Charge</u>	\$7.00	\$7.00
<u>Demand Charge</u> - Per KW	\$6.51	\$2.18
<u>Energy Charge</u> - Per KWH		
On-Peak	1.69¢	1.48¢
Off-Peak	0.43¢	0.38¢

Note: For a customer first taking service in the October through May period, all kilowatt hours will be billed monthly at 3.45¢ per KWH. There shall be no demand charge but the customer charge shall apply. This provision will only apply during the Customer's initial October through May period.

D. Fuel Adjustment

All kilowatt hours billed under this service classification shall be subject to the fuel adjustment clause as provided in Section XIX of the rules and regulations.

Delmarva Power & Light Company of Maryland

SERVICE CLASSIFICATION "R-PLP"

RESIDENTIAL - PEAK LOAD PRICING SERVICE - Continued

E. Peak Hours

Peak hours are 8:00 a.m. to 10:00 p.m. during periods of the year when Eastern Standard Time is in effect, and 9:00 a.m. to 11:00 p.m. when Eastern Daylight Savings Time is in effect, Monday through Friday, including holidays falling on weekdays. All other hours are off-peak hours.

F. Measured Demand

The measured demand shall be the greatest demand established during any sixty (60) minute period of the month during the on-peak hours, taken to the nearest one-tenth kilowatt.

G. Billing Demand

The summer billing demand for each of the billing months of June through September shall be the maximum measured demand as created in that month. The greatest billing demand as created during the most recent summer billing months shall remain in effect for each of the ensuing winter billing months ending with the May billing month. For customers first taking service during the October through May period, there shall be no billing demand. This provision will only apply during the customer's initial October through May period.

H. Minimum Charge

The minimum monthly charge shall be the customer charge plus the demand charge. Minimum charges shall not be prorated for periods of less than one month.

I. Primary Discount

Where service is supplied and metered at primary voltage, as defined in Section XI-D of the rules and regulations, and the Customer owns and maintains the required transforming, switching and protection equipment, the monthly bill will be decreased by \$0.28 per KW before the application of the fuel adjustment clause or any tax imposed by governmental authority upon the Company's sales.

J. Rules and Regulations

The rules and regulations set forth in this tariff shall govern the supply of service under this service classification.

In addition, the PSC should require Delmarva to furnish evidence that the company has selected appropriate rating periods. Our specific findings regarding Rate R-PLP are given in the remainder of this chapter.

As shown in Exhibit 1.d, Rate R-PLP is based on accounting costs. The rate consists of a separately stated customer charge, a seasonally differentiated peak demand (kW) charge, and seasonally differentiated peak and off-peak energy (kWh) charges. The methods used to develop Rate R-PLP are described in the direct testimony of Paul Gerritsen filed with the PSC in Case No. 7174 on June 30, 1978. After examining Mr. Gerritsen's testimony, questioning him regarding the methods used to design the rate, and examining the work papers containing the calculations of the charges included in the rate, we found the methods used to design Rate R-PLP to be reasonable. However, we believe that two principal adjustments to the methods are appropriate.

First, Delmarva should verify its estimates of seasonal peak and off-peak consumption (kW and kWh) that were derived using load research data collected from a survey of 90 residential customers in Delaware. Unless Delmarva can demonstrate that the load and consumption patterns of these Delaware customers are similar to the load and consumption patterns of Maryland customers, load research data should be collected from customers in Maryland. Furthermore, regardless of the origin of the load research data, the PSC should ascertain whether a sample size of 90 residential customers is sufficient to provide statistically reliable estimates of consumption patterns.

Second, Delmarva should modify the fuel adjustment clause contained in Rate R-PLP to ensure that monthly fluctuations in the ratio of peak to off-peak energy charges are prevented. For example, the ratio of the proposed peak to off-peak energy charges in the summer months is 3.93. If a fuel adjustment charge of 5 mills per kWh is added to peak and off-peak prices, the ratio will fall to 2.35, a decrease of 40 percent. One purpose of offering an optional TOD rate to residential customers is to determine the potential changes in consumption patterns created by time-differentiated rates, and the ratio of peak to off-peak prices must be maintained for the PSC and Delmarva to obtain reliable estimates of demand

elasticities. We believe the PSC and Delmarva could agree on a modification of the fuel adjustment clause that would be equitable and cost related, yet allow the peak to off-peak price ratio to remain the same.

Delmarva could further adjust its method for developing the residential TOD rate. For example, Delmarva used load factors based on noncoincident peak demands to estimate seasonal billing demands. We believe this method results in an overstatement of the kW that will be billed under the TOD rate and an understatement of the peak demand charges required for the seasonal rating periods. However, until more detailed load research data are available, Delmarva's method of estimating billing demands for seasonal rating periods should be considered adequate.

2 SEASONAL ELECTRIC RATES

As part of its investigation of alternative electric utility rate structures, the Maryland PSC ordered "that each electric company, with gross annual revenues exceeding \$25,000,000 shall study present seasonal rate differentials [seasonal electric rates] and recommend to the Commission, on or before January 1, 1978, any change in degree or application that would be practical and in the interest of fairness and conservation."*

A seasonal electric rate is a TOU rate that relates the price of electricity to the seasonal costs of providing that electricity. Because generating costs are greatest during system peak periods, rates based on seasonal price differentials will be higher during the season with the higher system peak. For example, a residential rate schedule for a utility with a high summer system peak relative to its winter peak might contain a customer charge of \$5.00 per customer per month and seasonal energy charges of \$0.05 per kWh for all consumption during the months of June through September and \$0.03 per kWh during the months of October through May.

As stated in the previous chapter, we recommend that the PSC require the Maryland utilities to develop rates reflecting the different costs of providing service according to time of use. Where TOD rates cannot be implemented easily (i.e., customers do not already have metering capable of measuring usage by time of day and are not willing to pay the additional costs of such metering), the PSC should order the utilities to develop seasonal rates. Although seasonal rates can promote increased efficiency of electricity consumption and production by reducing demand during seasonal peak periods and encouraging load growth during off-peak periods, TOD

* Maryland PSC, Case No. 6808, Order No. 62568, p. 4.

rates, which address daily, rather than just seasonal, peaks, can more effectively meet the PSC's goal. Consequently, seasonal rates should only be used where TOD rates are not currently practical and should be part of a broader TOU program stressing TOD rates.

In the following sections, we present the requirements for developing effective seasonal rates and the results of our evaluation of the utilities' responses regarding existing and proposed seasonal rate differentials.

REQUIREMENTS FOR DEVELOPING SEASONAL RATES

The primary reasons for implementing seasonal electric rates are to:

- Recognize the seasonal cost differences of providing electricity to consumers
- Reduce demand and energy consumption during the peak season
- Improve a utility's annual load factor by encouraging the development of load growth and energy use during the off-peak season.

Seasonal electric rates can meet the Maryland PSC's goal of increased efficiency of electricity consumption and production. Production efficiency is increased as demand and, hence, utilization of generation equipment become more balanced from a decrease in seasonal peak consumption and an increase in seasonal off-peak consumption. Electricity consumption is made more efficient, because seasonal prices paid by consumers reflect the utility's cost of providing electric service more accurately than do nontime-differentiated rates.

Although seasonal electric rates can be beneficial in terms of increasing consumption and production efficiency and reducing future capacity requirements, such rates should only be instituted when:

1. A utility's summer peak demand is significantly greater (e.g., 400 kw-1,000 kw) than its winter peak demand, or vice versa

2. A utility's planned capacity expansion is based on meeting demand during a particular season (rather than year round)
3. A utility expects its peak demand to occur consistently during the same season
4. A utility can estimate the difference between the cost of meeting demand during summer and winter seasons
5. A utility can determine that the benefits arising from the rates exceed the costs of introducing them.

The first four requirements are self-explanatory; the fifth requirement needs further elaboration. Because traditional kWh meters can be used to measure consumption on a seasonal basis, the direct costs (i.e., metering costs) to a utility of implementing seasonal rates are minimal. The benefits of such rates, however, can be large or small; and, in some cases, seasonal rates can result in a decreased annual load factor. For example, if a utility with a large air-conditioning load increased its summer kWh charges relative to its winter (or nonsummer) charges for residential and small commercial customers, the total number of hours during which air conditioners were being operated could decrease without a corresponding decrease in the system's peak demand. This could occur because customers would still be willing to pay the higher seasonal rates on the hottest and most humid days of the year (i.e., peak demand days). In such a case, the benefits of seasonal rates would be determined by the extent to which the lower seasonal rates would encourage consumption during the off-peak season. Increased off-peak seasonal consumption could either offset a decrease in peak seasonal consumption or improve the load factor. If possible, the effects of seasonal rate differentials on the load and consumption patterns of the participating customers should be calculated to determine the benefits of such rates.

Regardless of whether seasonal rates result in a large or small improvement in a utility's load factor, customers should be charged rates based on the actual costs of providing electric service. Only when rates are designed to

reflect these cost differences can consumers make reasonable and efficient decisions about how and when to consume electricity. Therefore, we recommend that where TOD rates cannot be easily implemented, utilities provide rates based on estimates of the cost differences of producing electricity during different seasons. After the cost differences have been estimated, load and billing data by customer classification should be used to develop the seasonal rate differential for each customer group or rate schedule.

EVALUATION OF UTILITIES' SEASONAL RATE PROGRAMS

Both BG&E and Delmarva consistently experience annual system peak demands during the summer months. Delmarva currently offers seasonal rates to its residential, commercial, and industrial customers and has submitted new rates to the PSC; BG&E has proposed seasonal rates for the same categories of customers. In general, the rate changes proposed by both utilities are beneficial in terms of improving the efficiency of energy production and consumption.

In the following subsections, we describe each utility's response regarding seasonal rate differentials and our recommendations to each utility.

Baltimore Gas and Electric Company

Since 1959, BG&E's annual system peak has occurred during the summer months (i.e., June-September). BG&E's load forecast indicates that between 1978 and 1987, the summer peak in any year will be approximately one-third higher than the winter peak in the same year.* Because BG&E expects its annual peak to continue to occur during

* BG&E, Response to Order No. 62568 in PSC Case No. 6808, December 1977, p. B-3.

the summer months, the company favors the use of seasonal electric rates as a means of improving its annual load factor.*

Pursuant to PSC Order No. 62733 in Case No. 7070, BG&E filed rate changes (including seasonal price differentials) considered by the company to be optimal for Schedules R, G, and T (see Exhibits 2.a, 2.b, and 2.c).** On the basis of our review, we recommend the implementation of the company's proposed changes, especially those relating to the use of seasonal differentials in Schedules G and T. However, the seasonal rates should be implemented only if the PSC decides not to require the use of TOD rates. If TOD rates are required for customers who already have the necessary metering, seasonal rates will not be applicable to Schedule T customers.

The proposed changes in BG&E's rate schedules are described in the following subsections.†

Proposed Changes for
Residential Customers

For Schedule R (residential) customers, the company recommends a separately stated customer charge, reducing the number of energy blocks from five to two, retaining the seasonal price differential for all use over 500 kWh, and shortening the summer period to include only the four billing months of June-September (see Exhibit 2.a). These changes should improve the design of Schedule R.

* The company's annual load factor usually is between 55 percent and 60 percent.

** The PSC is considering these changes in Case No. 7159.

† Our comments are not intended to support or reject the specific prices and energy and demand blocks included in Schedules R, G, and T. Our comments are based solely on our conception of the proper design for rates; namely, separately stated customer charges are justified and should be used, kW and kWh charges should be used whenever possible, and demand and energy blocks should be kept to a minimum.

RESIDENTIAL SERVICE-ELECTRIC

SCHEDULE R

Availability:

(a) For use for the domestic requirements of:

- (1) A single private dwelling.
- (2) An individually metered dwelling unit in a multiple dwelling building.
- (3) A single farm dwelling, including requirements for related farm purposes where served through the same meter.
- (4) One combination of two dwelling units within a building, if served through a single meter.
- (5) A dwelling occupied as the dwelling place of a church divine or of religious associates engaged in church duties.
- (6) A single dwelling within a building where the occupant has not more than 10 bedrooms to let or not more than 10 table boarders, or a combination of not more than ten.

(b) For use, if on one property and served through a single meter, of a combination of the occupant's domestic requirements in a dwelling and his nondomestic requirements, provided the predominant use is for domestic purposes.

(c) For use, if served through a separate meter, by appliances used in common by the occupants of not more than two dwelling units within a building.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Customer Charge: \$ 3.93 per month plus.

Energy Charge:

	500			
	For the first [40] kWh	3.653c		[8.68c] per kWh
	[For the next 110 "		5.69c	" "
	[For the next 150 "		4.12c	" "
	[For the next 200 "		3.26c	" "
	For all over 500 kWh			
	four -For [five] billing periods ending between			
June, September	[Mid May] and [Mid October].	3.653c		[3.26c] " "
	eight -For [seven] billing periods ending between			
October, May	[Mid October] and [Mid May].	2.260c		[2.26c] " "

Fuel Rate Adjustment: Applies to all electricity supplied. (Rider 1)

\$3.93

Minimum Charge (Net): [\$1.89] per month[, plus the Fuel Rate Adjustment on kWh supplied.]

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Subject to riders applicable as listed in Rider Index.

GENERAL SERVICE - ELECTRIC

SCHEDULE G

Availability:

For use for all purposes.

Delivery Voltage: Service at Secondary Distribution Systems voltages, or at Primary Systems voltages (Rider 15).

Monthly Net Rates:

Customer Charge: \$9.71 per month plus,

	For Four Billing	For Eight Billing
	Periods Ending Between	Periods Ending Between
	<u>June to September</u>	<u>October to May</u>

Demand Charge:

<u>all kW over</u>			
For the first 60 kW of billing demand	<u>\$4.76</u>	per kW	[None] <u>\$2.38</u> per kW
[For the next 440 kW of billing demand			\$3.26 per kW]
[For the excess over 500 kW of billing demand.			\$3.05 " "]

Energy Charge:

<u>2,700</u>	For the first	[60] kWh	<u>6.95c</u>	per kWh	[8.68c]	per kWh	<u>4.64c</u>
<u>21,300</u>	For the next	[2,640] "	<u>4.20c</u>	" "	[5.97c]	" "	<u>2.90c</u>
	[For the next	6,800 "			4.18c	" "]
	[For the next	15,000 "			2.84c	" "]
	For the next	75,000 "	<u>2.34c</u>	" "	[2.34c]	" "	<u>2.34c</u>
	[For the next	175,000 "			2.08c	" "]
<u>99,500</u>	For all over	[274,500] "	<u>1.86c</u>	" "	[1.67c]	" "	<u>1.86c</u>

Fuel Rate Adjustment: Applies to all electricity supplied. (Rider 1) for the month.

Billing Demand: The maximum measured demand (Rider 11) (in the 12 months ended with the current billing month if such demand is less than 75 kW; otherwise, the maximum measured demand for the month but not less than 75 kW; and in either event not less than two-thirds of the maximum billing demand, up to 200 kW, in the months of June to September, inclusive, of the preceding 11 months plus one-half of the excess (if any) of such maximum billing demand over 200 kW.)

Minimum Charge [(Net)]: \$9.71 [(Net)]: [\$1.89] per month plus the Demand Charge, if any, and the Fuel Rate Adjustment on kWh supplied.]

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: One to 3 years, dependent upon extension and demand requirements (Rider 21), and thereafter until terminated by at least 30 days' notice from the Customer.

Subject to riders applicable as listed in Rider Index.

SERVICE AT 13,200 VOLTS AND OVER

SCHEDULE T

Availability:

For use for all purposes, for demands of 200 kW or more.

Delivery Voltage: Three-phase, 13,200 volts and over.

Monthly Net Rates:

Customer Charge: \$ 253 per month plus,

Demand Charge:

<u>For each kW of billing demand</u>	
[For the first 200 kW (or less) of billing demand]	\$.568]
[For the next 1,800 kW of billing demand.]	\$.2.82 per kW]
[For the excess over 2,000 kW of billing demand]	\$.2.43 " "]
<u>- For four billing periods ending between</u>	
<u>June and September</u>	<u>\$.3.80 per kW</u>
<u>- For eight billing periods ending between</u>	
<u>October and May</u>	<u>\$.1.89 " "</u>

Energy Charge:

<u>300,000</u> For the first [50,000] kWh	[2.14¢] per kWh	<u>1.87c</u>
[For the next 250,000 "]	1.94c " "]	
<u>500</u> For the next [300] kWh per kW of billing demand	[1.44¢] " "]	<u>1.40c</u>
[For the next 200 kWh per kW of billing demand]	1.25c " "]	
For all over	[1.11¢] " "]	<u>1.10c</u>

Fuel Rate Adjustment: Applies to all electricity supplied. (Rider 1)

Minimum Charge: \$253 per month plus the Demand Charge.

Billing Demand: The maximum measured demand (Rider 11) for the month[, but not less than one-half of the maximum billing demand in the months of June to September, inclusive, of the preceding 11 months.] excluding measured demands in the off-peak periods (Rider 12), but in no case less than 200 kW.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Five years and thereafter until terminated by at least 30 days' notice from the Customer.

Subject to riders applicable as listed in Rider Index.

Where customer-related costs can be estimated, a separately stated customer charge, as proposed, should be used to recover these costs.

The flat energy charge in the summer and the lower tail block rate in the winter correspond to the seasonal differences in the costs of serving residential customers. However, if TOD rates are implemented, they should be offered, rather than seasonal rates, to residential customers willing to pay the additional metering costs.

Proposed Changes for Small General Service Customers

BG&E proposes to modify Schedule G (applicable to small general service customers) by introducing a separately stated customer charge, replacing the existing demand rates and demand ratchet with different summer and winter demand rates applicable to all consumption exceeding 60 kW, reducing the number of energy blocks from seven to four, and introducing a seasonal price differential for monthly consumption of up to 24,500 kWh (see Exhibit 2.b).*

BG&E's proposal to replace the billing demand ratchet with seasonal demand rates for customers consuming more than 24,500 kWh and to introduce a seasonal energy price differential as a price signal to smaller general service customers (i.e., customers with demands under 60 kW) should encourage customers to conserve electric energy and to improve their monthly and annual load factors. However, TOD rates, not seasonal rates, should be offered to those willing to pay the additional costs of metering.

Proposed Changes for Large General Service Customers

BG&E's proposed revisions to Schedule T (applicable to large general service customers) consist of introducing a separately stated customer charge; replacing the three existing demand blocks with different summer

* For energy use exceeding 24,500 kWh, the seasonal demand rates will be in effect.

and winter demand charges, eliminating the billing demand ratchet, and using only the maximum demand registered between 8:00 a.m. and 11:00 p.m. on weekdays to calculate a customer's monthly billing demand; and reducing the energy blocks from five to three.

RPA believes these proposed changes would improve the design of Schedule T and should encourage Schedule T customers to improve their load factors and use electricity more efficiently. However, we also believe that BG&E should explain the reason for not including a seasonal differential in the energy charges in Schedule T. Furthermore, if the PSC decides to require TOD rates for all customers having the necessary metering, Schedule T will become a TOD rate, as these customers' usage is currently measured by magnetic tape recording meters.

Delmarva Power & Light
Company of Maryland

Delmarva's system peak consistently occurs during the summer months (when it is significantly higher than the nonsummer peak) and is expected to continue to occur during the summer.* In recognition of the higher cost of supplying electricity during the summer, Delmarva already provides seasonal rates for its residential, commercial, and industrial customers in Maryland.

Because Delmarva's response to Order No. 62568 indicates that the company was unable to make specific recommendations to the PSC regarding the appropriateness of the company's current seasonal rates, RPA examined Delmarva's proposed seasonal rates filed on June 30, 1978.** In this case, Delmarva presented three seasonal rates and one TOD rate for the PSC's consideration. The seasonal rates are applicable to residential customers (Rate R), general service customers receiving service at the primary and secondary voltage levels (Rates GS-P and GS-S, respectively), and customers presently served

* For a complete description of Delmarva's expected load growth, see Delmarva, System Long-Range Electric Load and Energy Forecast: 1978-1997, December 16, 1977.

** Maryland PSC, Case No. 7174.

under Public Authorities Rate 5 and High Tension Rate HT (Rates GS-S and GS-P, respectively). The proposed changes to these rates are shown in Exhibits 2.d, 2.e, and 2.f.

The proposed rates presented in Case No. 7174 are based on the 1978 forecast cost-of-service study filed in Case No. 7236 that was filed in support of a request for a general increase in Delmarva's electric service rates in Maryland.* Because RPA is not a party of record in Case No. 7236, we limit our comments on Delmarva's seasonal rates filed in Case No. 7174 to the design of the rates.**

The methods used by Delmarva to develop the seasonal differentials included in the residential and general service rates in Case No. 7174 appear to be reasonable. We examined testimony relating to the development of these rates, the cost-of-service study on which the rates are based, and the company's work papers showing the allocations used to derive unit customer costs and seasonal demand and energy costs.

We consider Delmarva's proposed seasonal differentials to be practical and feasible alternatives to TOD pricing for relatively small general service and residential customers (i.e., those customers who do not already have TOD metering or are unwilling to pay the additional costs of such metering). However, the PSC should require Delmarva to demonstrate that sufficient load research data were available to derive the allocation factors used to develop the seasonal differentials.

In the remainder of this chapter, we describe the proposed rate changes shown in Exhibits 2.d, 2.e, and 2.f.

* A detailed description of the methods used to develop Rates R, GS-S, and GS-P for Case No. 7174 is given in the testimony filed in this case by Paul Gerritsen, Supervisor of Rates for Delmarva.

** We do not comment on the appropriate level of revenues that should be generated by the rates.

Delmarva Power & Light Company of Maryland

SERVICE CLASSIFICATION "R"

RESIDENTIAL SERVICE

A. Availability

This rate applies throughout the territory served by the Company in the State of Maryland and is available to a Customer desiring service for household and other related uses in a single private dwelling or dwelling unit, farmstead or estate and pertinent detached buildings.

B. Contract Term

Residential contracts are on a month-to-month basis until terminated.

C. Monthly Rate

Billing Months - June through September

\$5.00 customer charge plus 5.94¢/KWH

Billing Months - October through May

\$5.00 customer charge plus 3.45¢ for each KWH up to and including the maximum kilowatt hours billed in any of the preceding billing months of June through September plus 0.38¢ for each additional KWH.

Note: For a customer first taking service during the October through May period, all kilowatt hours will be billed at 3.45¢ per KWH.

D. Fuel Adjustment

All kilowatt hours billed under this service classification shall be subject to the fuel adjustment clause as provided in Section XIX of the rules and regulations.

E. Minimum Charge

The minimum monthly charge shall be the customer charge. Minimum charges shall not be prorated for periods of less than one month.

F. Primary Discount

Where service is supplied and metered at primary voltage, as defined in Section XI-D of the rules and regulations, and the customer owns and maintains the required transforming, switching and protective equipment, the monthly bill will be decreased by 0.22¢ per KWH before the application of the fuel adjustment clause or any tax imposed by governmental authority upon the Company's sales.

SERVICE CLASSIFICATION "R"

RESIDENTIAL SERVICE - Continued

G. Rules and Regulations

The rules and regulations set forth in this tariff shall govern the supply of service under this Service Classification.

SERVICE CLASSIFICATION "GS-S"

GENERAL SERVICE - SECONDARY

A. Availability

This rate is available to any customer desiring service at secondary voltage as defined in Section XI-D of the Rules and Regulations.

B. Contract Term

Contracts, when required, are for an initial period of one (1) year with automatic month-to-month extensions until terminated. A contract for an initial period of more than one (1) year may be required if special investment by the Company is necessary or for demands greater than one thousand kilowatts (1,000 KW).

C. Monthly Rate

	<u>Billing Months</u> <u>June through September</u>	<u>Billing Months</u> <u>October through May</u>
<u>Demand Charge</u> - per KW	\$11.82	\$5.23
<u>Energy Charge</u> - per KWH	1.22¢	1.02¢

D. Fuel Adjustment

All kilowatt hours billed under this Service Classification shall be subject to the Fuel Adjustment Clause as provided in Section XIX of the Rules and Regulations.

E. Measured Demand

1. The measured demand shall be the greatest demand established by the customer during any fifteen (15) minute period of the month as measured by demand meter, except as modified by paragraph 2.
2. When a customer has contracted for off-peak service, the measured demand shall be that which occurs during peak hours, provided that the measured demand so determined shall not be less than one third (1/3) of the measured demand established during off-peak hours.

Delmarva Power & Light Company of Maryland

SERVICE CLASSIFICATION "GS-S"

GENERAL SERVICE - SECONDARY - Continued

F. Off-Peak Service

Peak hours are 8 a.m. to 10 p.m. Monday through Friday, including holidays falling on weekdays. All other hours are off-peak hours.

The availability of off-peak service is subject to agreement in writing between the Company and the customer. There shall be an additional charge of \$8.75 per month for such service. The Company reserves the right to restrict the amount of off-peak power available to any individual customer and to restrict the total amount of off-peak power available on its system.

G. Power Factor

When the measured demand is 150 KW or more for the current month or any of the previous eleven (11) months, the average power factor of the customer's installation, expressed in the nearest whole percent, shall be determined by metering installed by the Company ratcheted to prevent reverse registration. Ninety percent (90%) lagging shall be considered to be the base power factor.

If the average power factor is determined to be below ninety percent (90%) for any given month, an additional charge of \$0.02 per kilowatt of billing demand for every whole percent less than ninety percent (90%), will be added to the monthly bill. If the average power factor is determined to be between ninety percent (90%) and one hundred percent (100%) for any month, a credit of \$0.02 per kilowatt of billing demand for every whole percent above ninety percent (90%) will be applied to the monthly bill.

H. Billing Demand

The summer billing demand for each of the billing months of June through September shall be the greater of the contracted demand, if applicable, or the maximum measured demand as created during each month. The greatest billing demand as created during the most recent summer billing months shall remain in effect for each of the ensuing winter billing months ending with the May billing month.

I. Minimum Charge

The minimum monthly charge shall be the demand charge. Minimum charges will not be prorated for periods of less than one month.

J. Water Heating

This provision is closed to new customers and to changes in existing service for existing customers.

SERVICE CLASSIFICATION "GS-S"

GENERAL SERVICE - SECONDARY - Continued

J. Water Heating - continued

At the customer's option, service for water heating will be rendered on a separate circuit and separately metered and billed at 2.62¢ per KWH. The total connected load of this circuit shall be limited to one hundred watts (100 W) per gallon of tank size or six thousand watts (6,000 W); whichever is larger. Water heating installations shall be subject to Company's approval and be open to Company inspection at all reasonable times. Minimum bills for such separate circuit will be \$2.90 per month.

K. Space Heating

This provision is closed to new customers and to changes in existing service for existing customers.

Service for permanently installed electric space heating equipment may, at the option of the customer, be rendered on a separate circuit and separately metered, if such heating equipment is the exclusive heating source for the space to be heated, and if such heating equipment is adequate to heat such space under normal design temperatures and totals five (5) kilowatts in capacity or more. In determination of adequate installed electric space heating capacity to qualify for the separate service and meter under this rate provision, the decision of the Company shall be final. A customer may also include water heating equipment in such separate circuit, and in addition equipment for cooling the air exclusively in the same space heated through the separate circuit.

Service for the separate circuit shall be billed at the rate of 2.49¢ per kilowatt hour during the billing months of October through May, inclusive, and at the rate of 3.49¢ per kilowatt hour during the months of June through September, inclusive, except as follows: If the customer shall be cooling the air, in addition to heating, in the space exclusively heated electrically, then during the billing months of June through September, inclusive, if the customer's usage measured over his basic meter is less than 2,500 kilowatt hours in any such billing months, the customer shall pay at the applicable rate over the basic meter for that portion of the kilowatt hours measured over the separate meter which will be required to make the total of such customer's measured use for such billing month over his basic meter and his separate meter together total 2,500 kilowatt hours, and he shall pay for the remainder of his measured use over his separate meter at the rate of 3.49¢ per kilowatt hour. The customer shall not be required, however, to pay for more than the total use measured on both meters.

The minimum bill for the space heating account for the period consisting of the seven billing months of October through May, inclusive, shall be \$5.08 for each kilowatt of installed space heating equipment, or a total of \$92.22 whichever is the greater. There shall be no minimum bill for space heating accounts for the billing months of June through September, inclusive.

SERVICE CLASSIFICATION "GS-S"

GENERAL SERVICE - SECONDARY - Continued

L. Rules and Regulations

The rules and regulations set forth in this tariff shall govern the supply of service under this service classification.

Delmarva Power & Light Company of Maryland

SERVICE CLASSIFICATION "GS-P"

GENERAL SERVICE - PRIMARY

A. Availability

This rate is available to any customer desiring service at primary voltage as defined in Section XI-D of the Rules and Regulations, and who owns and maintains the required transforming, switching and protection equipment.

B. Contract Term

Contracts, when required, are for an initial period of one (1) year with automatic month-to-month extensions until terminated. A contract for an initial period of more than one (1) year may be required if special investment by the Company is necessary or for demands greater than one thousand kilowatts (1,000 KW).

C. Monthly Rate

	Billing Months <u>June through September</u>	Billing Months <u>October through May</u>
<u>Demand Charge</u> - Per KW	\$11.48	\$3.95
<u>Energy Charge</u> - Per KWH	0.99¢	0.85¢

D. Fuel Adjustment

All kilowatt hours billed under this service classification shall be subject to the Fuel Adjustment Clause as provided in Section XIX of the Rules and Regulations.

E. Measured Demand

1. The measured demand shall be the greatest demand established by the customer during any fifteen (15) minute period of the month as measured by demand meter, except as modified by paragraph 2.
2. When a customer has contracted for off-peak service, the measured demand shall be that which occurs during peak hours, provided that the measured demand so determined shall not be less than one third (1/3) of the measured demand established during off-peak hours.

Delmarva Power & Light Company of Maryland

SERVICE CLASSIFICATION "GS-P"

GENERAL SERVICE - PRIMARY - Continued

F. Off-Peak Service

Peak hours are 8 a.m. to 10 p.m. Monday through Friday, including holidays falling on weekdays. All other hours are off-peak hours.

The availability of off-peak service is subject to agreement in writing between the Company and the customer. The Company reserves the right to restrict the amount of off-peak power available to any individual customer and to restrict the total amount of off-peak power available on its system.

G. Power Factor

The average power factor of the customer's installation, expressed to the nearest whole percent, shall be determined by metering installed by the Company ratcheted to prevent reverse registration. Ninety percent (90%) lagging shall be considered to be the base power factor.

If the average power factor is determined to be below ninety percent (90%) for any given month, an additional charge of \$0.02 per kilowatt of billing demand for every whole percent less than ninety percent (90%) will be added to the monthly bill. If the average power factor is determined to be between ninety percent (90%) and one hundred percent (100%) for any month, a credit of \$0.02 per kilowatt of billing demand for every whole percent above ninety percent (90%) will be applied to the monthly bill.

H. Billing Demand

The summer billing demand for each of the billing months of June through September shall be the greater of the contracted demand, if applicable, or the maximum measured demand as created during each month. The greatest billing demand as created during the most recent summer billing months shall remain in effect for each of the ensuing winter billing months ending with the May billing month.

I. Minimum Charge

The minimum monthly charge shall be the demand charge. Minimum charges will not be prorated for periods of less than one month.

J. Rules and Regulations

The Rules and Regulations set forth in this tariff shall govern the supply of service under this service classification.

Proposed Seasonal
Price Differential
for Residential Rates

Delmarva's proposed residential Rate R contains a seasonal differential with a kWh energy ratchet (see Exhibit 2.d). All kWh consumed during the summer billing months (June-September) would be billed at 5.94 cents. During the winter billing months (October-May), 3.45 cents would be charged for each kWh up to the maximum kWh billed in any of the preceding summer months; all additional kWh would be priced at 0.38 cents.

In general, kWh energy ratchets should not be applied to residential rates, because the ratchets penalize customers who consume most of their seasonal peak energy during daily off-peak periods. However, two aspects of the proposed seasonal differentials for Rate R merit serious consideration by the PSC. First, the kWh charge during the summer billing months is 1.72 times greater than the energy charge during the winter months applicable to the level of consumption established by the energy ratchet. Second, the energy charge applicable to the level of consumption established by the energy ratchet is about nine times greater than the kWh charge for consumption in excess of this level. These rate differentials, if understood by residential customers, should encourage customers to conserve electric energy during the summer billing months in order to avoid higher charges during the winter billing periods. However, Delmarva's annual load factor will increase only if the large seasonal price differentials result in a growth in winter load and sales that is greater than the reduction in energy consumed during the summer months.

Prior to making a decision regarding these proposed seasonal differentials, the PSC should require Delmarva to:

1. Explain the rationale behind, and the revenue effects of, the energy ratchet included in the residential rate (Rate R)
2. Demonstrate that the low kWh charge for consumption in excess of the level established by the energy ratchet in Rate R approximates the actual cost of off-peak energy to the company.

Proposed Seasonal
Price Differentials
for General Service Rates

The company's proposed general service rates, Rates GS-S and GS-P, contain seasonal differentials for both the demand and energy charges and 100-percent demand ratchets, i.e., a customer's maximum demand in the summer becomes the customer's minimum billing demand during the winter billing months (October-May). Neither rate contains a separate customer charge. (See Exhibits 2.e and 2.f.)

The ratios of summer-to-winter demand charges are 2.26 and 2.90 for Rates GS-S and GS-P, respectively. Given these differentials and the 100-percent demand ratchet, general service customers should be encouraged to keep their summer peak demands as low as possible. However, the application of seasonal demand ratchets to all general service customers can penalize certain customers in the same manner as seasonal energy ratchets can penalize certain residential customers. For example, a bakery owner with a maximum demand occurring between midnight and 5:00 a.m. (i.e., demand does not coincide with the utility's peak demand) would be forced to pay demand charges based on a maximum demand that does not contribute to the system's peak demand.

Although the potential adverse effects on load factor that can arise from using energy ratchets are reduced by using demand ratchets, Delmarva should attempt to determine whether the demand ratchet actually contributes to an increase in its annual load factor. In addition, the PSC should require Delmarva to:

1. Provide the PSC with alternative general service rates that include a separate customer charge
2. Estimate the potential effects of reducing the 100-percent demand ratchets in the general service rates and determine the feasibility of identifying customers whose highest measured demands occur during off-peak hours.



3

OFF-PEAK DISCOUNTS

The Maryland PSC is also considering off-peak discounts as a means of increasing the efficiency of energy consumption and production. To investigate the benefits of these discounts, the PSC ordered "that each electric company, with gross annual revenues exceeding \$25,000,000, shall file a report with the Commission, on or before January 1, 1978, which relates to the feasibility of establishing a provision for an off-peak discount for large commercial and industrial customers."*

Utilities can offer customers either explicit or implicit off-peak discounts. An explicit off-peak discount is equivalent to a TOD rate, i.e., the lower price charged for electricity consumed during off-peak periods is explicitly stated in a rate schedule. An implicit off-peak discount, such as BG&E's Rider 12 (see Exhibit 3.a), is stated not as a lower price for off-peak consumption but rather as an exclusion of some or all measured off-peak demands in the calculation of a customer's billing demand.

Historically, off-peak discounts have been made available only to large commercial or industrial customers whose consumption is measured by TOU meters (e.g., magnetic tape recording meters). As stated in Chapter 1, we recommend that customers with TOU meters be billed under TOD rates. If the PSC decides not to order the implementation of TOD rates for such customers, implicit off-peak discounts should at least be offered as incentives for large customers to shift electricity consumption to off-peak periods. However, based on our analysis of the implicit off-peak discounts offered by BG&E and Delmarva, we do not believe that this type of discount is very effective in terms of improving the efficiency of energy production and consumption.

* Maryland PSC, Case No. 6808, Order No. 62568, p. 4.

10. (Reserved for future use.)

11. Measured Demand

The measured demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter in any 30-minute interval. In billing under Schedule G it is adjusted to the nearest half kw, and under Schedule T it is adjusted to the nearest whole kw.

Where service is used in such a manner that the measured demand as defined above does not properly reflect the capacity which the Company is required to provide, the demand may be estimated by the Company, so as to reflect such capacity.

Where the power factor is found to be less than 75%, the Company reserves the right to base the demand on 75% of the kilovolt-amperes (kva) instead of on the kw.

●12. Night and Holiday Demand

Note: See Page 9 for Rider 12 Revision

The measured demand on Saturdays, Sundays and the following holidays and during the night hours from 9 pm to 8 am is reduced one-third in billing under Schedule T: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Election Day (National and State only), Thanksgiving and Christmas, and the Monday following each of these as fall on Sunday.

13. Initial Demand

During the first 6 months of service under Schedule T, the Billing Demand may be less than 200 kw but in that event is not subject to decrease (and the Demand Charge is per kw of such demand.) When it reaches 200 kw, the provisions of this Rider no longer apply

14. Demand Proration

During the first 6 months of the initial term of a contract for service, or by reason of the installation of additional equipment at any time and upon the Customer's request prior to the increase, the measured demand for billing purposes will be prorated under the following conditions:

The billing month is divided into three periods consisting of the first 10 days, the second 10 days, and the remaining days of the month. If the demand of the second or third periods individually, or the higher demand during the combined second and third periods, increases at least 10% over both (1) the demand of the preceding period of the billing month and (2) the maximum Billing Demand of the preceding month, the Billing Demand for the month is the average of the demands determined for each such period or periods weighted on the basis of applicable thirds of the month.

The above provisions are not applicable to a part-month Billing Demand of less than 200 kw, but such demands are adjusted to 200 kw to obtain the benefits of proration under this Rider.

●15. Service at Primary Systems Voltages

Service at a Primary System voltage is supplied where the conditions of use require distribution by the Customer at Primary System voltages, multiple or remotely located transformer locations, or where other conditions of use make it impracticable for the Customer to receive service at standard Secondary Distribution System voltages.

The Monthly Net Rates of Schedule G are subject to a discount of ^{13c} 16¢ per kw per month of Billing Demand for [the first 440 kw] in excess of 60 kw [and 10¢ per kw of excess over 500 kw] and for ^{all} kw uses in the following energy blocks: (0.28¢ per kwh for the [third and fourth blocks, 0.16¢] per kwh for ^{0.28 c} the [A] block and [0.1¢] per kwh for the excess use. ^{0.11 c} second block, 0.16 c

^{third} This Rider also applies (1) to the billing of a Customer newly receiving service where the Company specifies service at 34,500 volts as available for his load requirements but at the Customer's request, the Company at its expense provides transformation facilities for delivery at 13,200 volts, or (2) where a Schedule T Customer changes to Schedule G under the provisions of Rider 22.

Electric Service Tariff

12. Off-Peak Demand (Schedule T)

The measured demand occurring between the hours of 11 pm and 8 am on weekdays (Monday-Friday) and all hours on Saturdays and Sundays and the following National and State holidays is not used in determining the Billing Demand under Schedule T: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Election Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

• 22. Change of Schedule

A Customer receiving service under Schedule G may, at any time, contract for the service under Schedule T. Where the estimated cost of additional main facilities required for the supply of service at 13,200 volts and over does not exceed \$1,000, the initial term of contract under the latter schedule may be reduced by the number of consecutive months, immediately preceding the change of schedule, in which the Customer's Billing Demand under the former schedule at that location exceeds 175 kw, but in no event to less than 1 year; any such reduction in term is considered as reducing correspondingly or as eliminating the billing periods affected by Rider 13.

A Customer receiving service under Schedule T may, upon request, at any time after the expiration of the initial term of contract be billed, effective from the date of the first regular meter reading following the receipt by the Company of the request, for service after that date, under Schedule G, prior demands being disregarded. Billing under Schedule T may subsequently be resumed effective with the date of the first regular meter reading following the Customer's request for such resumption, for service after that date, prior demands under Schedule T being effective in the subsequent billing the same as though no lapse in billing under that schedule had occurred, but the foregoing provisions are not then available for application until the expiration of 1 year from the end of the period for which service was billed under Schedule G. The provisions of this paragraph are not applicable to service under Rider 17.

The provisions of the preceding paragraph are applicable during the initial term of contract under Schedule T, upon payment by the Customer to the Company of such an amount, if any, as would be held by the Company at the time of application of Schedule G, had the provisions of Sec. 8.5 (Temporary Use) applied to the service from the beginning of the contract, such payment to be subject to refund only in the event of a resumption of billing under Schedule T and, in that case, in full; in such event, the initial term of contract under Schedule T is extended by the amount of time during which the Customer was billed under Schedule G; and a further change by the Customer to Schedule G is not permitted until the expiration of the extended initial term of contract under Schedule T, but in no event until the expiration of 1 year from the end of the period for which service was billed under Schedule G.

A change from Schedule T to Schedule G is subject to the following additional provisions until such time as billing under the former schedule is resumed or service is supplied at other than Primary Systems voltage:

- (a) Transforming equipment to continue to be provided and maintained by the Customer, and metering to continue to be at Primary Systems voltage.
- (b) The Monthly Net Rates of Schedule G are subject to the discounts of Rider 15.

In the remainder of the chapter, we describe the requirements of implicit off-peak discounts and evaluate the utilities' responses to the PSC's order.

REQUIREMENTS OF IMPLICIT OFF-PEAK DISCOUNTS

To increase off-peak consumption and improve the system's load factor, some utilities offer implicit off-peak discounts. These discounts are designed to encourage customers to utilize more of the system's available capacity, particularly baseload capacity. If consumers respond to the lower implicit prices by increasing off-peak use relative to peak use, the utility's annual load factor will increase, and the utility's available capacity will be used more efficiently. In addition, shifts in use from the peak to the off-peak period may slow the growth in the utility's peak demand and, hence, the need for additional generating capacity.

To be most effective, implicit off-peak discounts should be related to the lower cost of meeting off-peak loads. However, given that implicit discount provisions do not include explicitly stated lower prices for off-peak consumption, it is impossible to determine whether implicit off-peak discounts accurately reflect the time-related cost differences of providing electric service. In addition, it is not possible to estimate the potential benefits of implicit off-peak discount provisions (i.e., load shifts and a higher system load factor) in tariffs applicable to large customers. Specifically, if elasticity estimates were available, the benefits of implicit off-peak discounts could not be estimated, because lower off-peak prices are not explicitly stated in the discount provisions.* An evaluation of the benefits of implicit off-peak discounts is limited to the assumption that large customers will respond to implicit discounts by

* For a survey of electricity demand studies and the problems of estimating elasticities, see L.D. Taylor, "The Demand for Electricity: A Survey," Bell Journal of Economics, Vol. 6, No. 1 (Spring 1975): pp. 74-110.

shifting usage to off-peak periods and thereby contribute to an increase in a utility's annual load factor.

EVALUATION OF UTILITIES' RESPONSES

Both utilities offer implicit off-peak discounts: BG&E to its large commercial and industrial customers; Delmarva to its large general service customers. In the following subsections, we describe these discounts and present our recommendations concerning each utility's response.

Baltimore Gas and Electric Company

The major off-peak discount provision available to BG&E's large commercial and industrial (Schedule T) customers (excluding seasonal rate differentials), is contained in Rider 12, which is applicable to service provided at 13.2 kilovolts (kV) and above (see Exhibit 3.a). Under Rider 12, measured demand during off-peak periods for Schedule T customers is reduced by one-third for billing purposes. Currently, off-peak time periods consist of the hours between 9:00 p.m. and 8:00 a.m. on weekdays, all hours on weekends, and all hours on certain holidays.

On December 13, 1977, BG&E filed with the Maryland PSC revised tariffs and riders pursuant to Order No. 62733 in Case No. 7070 (see Exhibit 3.a).^{*} In the proposed revision to Rider 12, all demands measured during weekends, on certain holidays, and during weekday hours between 11:00 p.m. and 8:00 a.m. will be excluded from the calculation of billing demands for Schedule T customers. In other words, the company proposes to shorten the weekday off-peak period by 2 hours and to ignore all off-peak demands when preparing bills. These changes in weekday off-peak hours are consistent with BG&E's proposed off-peak hours for TOD rates (see Chapter 1).

^{*} Currently, the PSC is considering these revisions in Case No. 7159.

Currently, BG&E allows Schedule G (general service) customers to move to Schedule T under the provisions of Rider 22 (see Exhibit 3.a). However, the minimum billing demand of 200 kW for Schedule T customers and the fact that Rider 12 is not available to Schedule G customers may prevent some relatively small customers from shifting loads to off-peak periods. Therefore, we recommend that BG&E examine the practicality and feasibility of offering the provisions of Rider 12 to Schedule G customers willing to pay the additional costs of TOD metering.

As stated in Chapter 1, further analyses should be performed to determine whether the 11:00 p.m. - 8:00 a.m. off-peak rating period is appropriate. We believe the risk of establishing new peaks at the beginning of the off-peak period is minimal. Furthermore, Rider 12 could be made available to all Schedule G customers willing to pay for the additional TOD metering without resulting in the peak period being extended into the beginning of the off-peak period. To minimize the risks of creating new peaks during the existing off-peak periods, the PSC and BG&E could limit the availability of Rider 12 to Schedule T customers and to a predetermined number of Schedule G customers. Using this cautious approach, the company could gain valuable information on the ability and willingness of Schedule G customers to shift loads. Such shifts could result in an improvement in BG&E's load factor and a reduction in the amount of expensive fuels used in generating plants during peak periods.

Nonetheless, BG&E's existing off-peak discounts are implicit rather than explicit and, as such, are not as potentially effective as direct price reductions (i.e., explicit discounts).

Delmarva Power & Light
Company of Maryland

Delmarva's current general service rate includes an optional off-peak discount provision. General service customers who contract for off-peak service can establish a measured off-peak demand up to three times their measured peak demand without increasing their monthly billing demand. The off-peak discount is available to any general service customer whose electricity consumption is currently measured by a magnetic tape recording meter, i.e., customers with demands exceeding 500 kW.

Delmarva intends to extend the use of these meters to record consumption by general service customers with demands exceeding 300 kW. Approximately five general service customers, none of whom are located in Maryland, have contracted for this off-peak service.

The general service rates (Rates GS-S and GS-P) filed by Delmarva in Maryland PSC Case No. 7174 also contain a provision for off-peak service (see Exhibits 2.e and 2.f in the previous chapter).^{*} During off-peak hours, which are defined as all hours other than the weekday (Monday-Friday) hours of 8:00 a.m. to 10:00 p.m., a customer who contracts for off-peak service can establish a measured demand up to three times his measured peak demand without increasing his billing demand. Customers who contract for off-peak service must pay Delmarva an additional \$8.75 per month, and Delmarva reserves the right to restrict both the amount of off-peak power available to a customer and the total amount of off-peak power available on its system.

Delmarva serves approximately 300 large general service customers with magnetic tape recording meters. About 70 of these customers are located in Maryland, yet no Maryland customers have contracted for off-peak service.

Several elements of the company's current and proposed general service rates may inhibit customers from contracting for off-peak service. Potentially inhibiting elements of Rates GS-S and GS-P filed in Case No. 7174 are the 100-percent demand ratchet, the lack of peak and off-peak energy charges, and the length of the peak rating period that requires customers to shift a significant portion of their peak load to the hours between 10:00 p.m. and 8:00 a.m. in order to improve their annual load factors and reduce their annual electricity bills (see Exhibits 2.e and 2.f). For example, assume an

* Although Delmarva did not submit examples of the specific off-peak provisions contained in its current general service rates, examples of the off-peak provisions for Delmarva's proposed general rates were available.

industrial customer has a constant demand of 1,000 kW during the peak hours of each month. Under Rate GS-P, this customer, who has an annual load factor of 0.42, will pay about \$110,200 per year for electricity. If this customer shifted 10 percent of his production to weekday off-peak hours, his constant demand during the peak hours of each month would decrease to 900 kW, and his constant demand during the off-peak hours would be 140 kW. The customer's annual load factor would increase to 0.46, and his annual electricity bill would decrease to around \$102,400. Thus, by shifting 10 percent of his load and production to weekday off-peak hours, the customer's annual electricity bill decreases by \$7,800, or about 7 percent. Because the relatively small decrease in the customer's annual electricity costs could be offset by increased operating costs, such as wage premiums for employees working between 10 p.m. and 8 a.m., customers may have little financial incentive to shift loads to off-peak hours.

Delmarva has demonstrated the feasibility of establishing an off-peak discount provision for large commercial and industrial customers. However, the off-peak discount is not used by any of Delmarva's 70 customers in Maryland with magnetic tape recording meters. We believe Delmarva should consider replacing the off-peak discount with a TOD rate for these customers. No additional metering would be required, the TOD rate would track the costs of serving these customers more accurately, and customers would have greater financial incentives to shift loads to off-peak hours.



4

AIR-CONDITIONING END-USE TARIFFS

To assess the feasibility and desirability of introducing end-use tariffs, the Maryland PSC ordered "that each electric company, with gross annual revenues exceeding \$25,000,000, shall submit to the Commission, on or before January 1, 1978, a report on the practicality of end-use tariffs for air-conditioning usage by large residential customers, as well as for office buildings and shopping centers."*

We do not believe that an end-use tariff for air conditioning (i.e., a special rate applicable to electricity used to power air conditioners) will significantly increase the load factors or decrease the peak demand growth of the Maryland utilities. In general, properly designed TOD and seasonal rates that use existing metering equipment can deal with problems caused by the growth in air-conditioning loads as effectively and less expensively than can special end-use tariffs for air conditioning.

In the following sections, we describe the requirements for implementing end-use tariffs and their effectiveness in increasing production and consumption efficiency. Finally, we assess the utilities' responses regarding the practicality of such tariffs.

REQUIREMENTS FOR DEVELOPING END-USE TARIFFS

End-use tariffs should reflect a utility's cost of providing electric service for a particular end use. However, most end-use tariffs are designed to promote or inhibit

* Maryland PSC, Case No. 6808, Order No. 62568, p. 4.

the use of electricity to power certain appliances or equipment and, as such, do not necessarily reflect the actual cost of providing service for the particular end use.

The rapid growth of air-conditioning loads in recent years has contributed to the increase in utilities' peak generating capacity requirements. An end-use tariff for air conditioning is a possible means of slowing the growth in air-conditioning loads and, hence, the growth in the utilities' peak demands. The assumption is that consumers would be encouraged to reduce their use of air conditioners if they were charged a relatively high price for the peak electricity used to power air conditioners.

We do not believe that an end-use tariff for air conditioning will significantly affect the growth in a utility's peak demand. Although a higher price for electricity used to power air conditioners may reduce the total kWh of air-conditioning use, consumers will probably be willing to pay the higher price on the hottest and most humid days of the summer when a utility's summer peak demand is most likely to occur. Consequently, the benefits of such a tariff will probably be small; in fact, needle peak problems might arise. Moreover, the potential energy-saving benefits of end-use tariffs for air conditioners will be further reduced by the costs of implementing such a program (additional metering is required) and the difficulties of metering residential window air conditioners.

Properly designed TOU rates (e.g., a seasonal electric rate with appropriately designed blocks for residential customers) make air-conditioning end-use tariffs an unnecessary complication in a utility's rate structure.

EVALUATION OF UTILITIES' RESPONSES

In their responses, neither BG&E nor Delmarva supports the implementation of end-use tariffs for air conditioning. A summary of our evaluation of each utility's response is presented in the following subsections.

Baltimore Gas
and Electric Company

Since 1959, BG&E's annual system peak demand has occurred during the summer months (i.e., June-September). BG&E's response indicates that the company believes this summer peaking characteristic has been caused by the rapid and extensive growth in the use of air conditioners by residential and commercial customers.*

BG&E recognizes that end-use tariffs for air conditioning will enable the company to charge relatively high rates for an end use that contributes greatly to the utility's summer peak demand. These high rates should decrease the demand for electricity to power air conditioners and encourage the development of energy-efficient cooling equipment.

However, the company realizes that an end-use tariff for air conditioners can create many problems. A major problem is the inequity of charging different prices for kWh consumed during the same time period by the same customer. Other problems include the costs of additional metering and wiring required to implement the tariff; the possibility of fraud by customers who rewire their air-conditioning system to the meter not used to measure kWh consumed by air conditioners; the use of portable window air conditioners to avoid the tariff; and the possibility of needle peaks occurring as consumers reduce their use of air conditioners on all but the hottest and most humid days (when the utility's summer peak is most likely to occur).

Delmarva Power & Light
Company of Maryland

Delmarva's response indicates the company believes that air-conditioning end-use tariffs are neither practical nor necessary to promote conservation. We agree with Delmarva that properly designed TOU rates, which are related to the time of consumption rather than the end use, can promote conservation and efficiency better than special end-use tariffs for air conditioning.

* In 1976, 77 percent of BG&E's residential customers had a central or room air conditioner.



5

MARGINAL-COST- BASED PRICING

As part of its investigation of potential rate structure changes that would promote efficient electricity production and consumption, the Maryland PSC ordered "that each electric company, with gross annual revenues exceeding \$25,000,000, shall file, on or before January 1, 1978, representative samples of rate structures which are based upon marginal cost principles and the revenue requirements as determined by the Commission in each company's most recent rate case."*

A principal axiom of microeconomics is that resources are optimally allocated when product prices equal their respective marginal costs. Marginal cost is the value of resources required to produce an additional unit of a commodity. If price represents the value consumers place on a commodity or service, the optimal production and consumption level of a commodity or service is reached when the price charged is equal to the marginal cost.

In recent years, regulators and utilities have indicated a strong interest in applying the principles of marginal-cost-based pricing to the electric utility industry. In 1974, the National Association of Regulatory Utility Commissioners requested the Electric Power Research Institute and the Edison Electric Institute to study TOD pricing and other novel approaches to electric rate design. A preliminary conclusion of this study was that "rates should reflect marginal costs to the extent possible."** RPA supports this conclusion.

In the following subsections, we present the requirements for developing marginal-cost-based rates (specifically, TOD rates) and our evaluation of the utilities' studies and rate structures based on marginal costs.

* Maryland PSC, Case No. 6808, Order No. 62568, p. 3.

** Electric Power Research Institute, November 1977, p. 3.

**REQUIREMENTS FOR DEVELOPING
MARGINAL-COST-BASED RATES**

When electricity rates reflect marginal costs, consumers are encouraged to use electricity efficiently, because they are being charged for the economic value of the electricity. Because some marginal costs tend to correspond to changes in demand on a utility's system, the changes in consumers' usage patterns in response to marginal-cost-based rates will promote the efficient utilization of existing generating capacity. Thus, rates that reflect marginal cost should promote efficiency in both the production and consumption of electricity, the PSC's principal goal.

As stated in Chapter 1, TOD rates should be based on marginal costs to reflect the time-related cost differences of providing electric service accurately. The marginal costs of supplying electricity can be divided into customer, demand, and energy categories. Strictly defined, marginal customer cost is the cost of serving an additional customer through the electric system; marginal demand cost is the cost of meeting a 1-kW increment in demand; and marginal energy cost is the cost of providing an additional kWh of energy. When attempting to develop TOD rates based on marginal costs, less theoretical and more practical definitions are required. To this end, we define marginal customer cost as the per customer cost of a distribution system that connects all customers and provides voltage but no power (i.e., the system can only meet minimum demands); marginal demand cost as the capacity cost of meeting incremental demands during a specified time period; and marginal energy cost as the fuel and operation and maintenance expenses incurred in meeting incremental kWh requirements during a specified time period.*

While RPA favors the use of marginal costs to develop TOD rates, we recognize that implementation of TOD rates may be delayed by the fact that the PSC and the utilities are not familiar with marginal cost methodologies. Therefore, to expedite implementation, accounting costs may be used

* Marginal demand costs include marginal generating capacity costs, transmission costs, and costs associated with the demand-related portion of the distribution system.

to develop TOD rates. However, because of the deficiencies in TOD rates based on accounting costs (see Chapter 1), the PSC should work closely with the utilities to ensure that TOD rates derived from accounting cost studies are acceptable. Moreover, the PSC should require the utilities to continue to develop marginal cost studies. The results of these studies provide information on (1) the time periods in which demands and costs are growing fastest and (2) which customers are responsible for that growth. The results of an accounting cost TOD study may not provide this information. In the short term, the information given in marginal cost studies should be used to adjust TOD rates based on accounting costs. In the long term, as marginal cost methodologies become understood, the utilities can develop rates based directly on marginal costs.

The PSC should not be misled by those who argue that TOD rates should be based on accounting costs, because there is no clearly defined and universally accepted method for estimating marginal costs.* There is also no clearly defined and universally accepted method for estimating time-differentiated accounting costs. The development of nonlinear production cost models, econometric load and sales forecast techniques, and refined methods for selecting rating periods will soon enable analysts to define and estimate marginal costs more precisely.

In the following subsections, we discuss two important issues related to marginal cost pricing:

1. Use of short- and long-run marginal costs
2. Reduction of excess revenue.

Use of Short- and Long-Run Marginal Costs

Short-run marginal cost (SRMC) is the cost of increasing output from a fixed amount of capacity, i.e., the additional variable cost incurred by increasing output.

* Long Island Lighting Company and Virginia Electric and Power Company were able to develop TOD rates based on marginal costs.

Long-run marginal cost (LRMC) is the cost of adjusting capacity and providing energy to meet an increase in demand during a specified time period in the future.

When an electric system has an optimal capacity mix (i.e., the total cost of meeting all demand is minimized), LRMC and SRMC are equal. However, in all other instances, if TOD rates are based on SRMC, the rates will have to be changed frequently to reflect fluctuations in SRMC as demands grow and the utility moves toward an optimal capacity mix. Therefore, to provide rate stability, we recommend that LRMC be used to develop marginal-cost-based TOD rates.

We recognize that, in some instances, modifications of LRMC may be required. For example, when a utility is switching from oil-fired to nuclear baseload capacity, rates must be adjusted, because the marginal energy costs of nuclear baseload capacity are lower than the current marginal energy costs of oil-fired units. In this case, energy rates based on LRMC should be increased to reflect more accurately existing and near-term operating conditions of the utility.

Reduction of Excess Revenue

Of major concern to utilities and regulators is the potential for excess revenue from rates based on marginal cost. If TOD rates are set to equal estimates of marginal demand, energy, and customer costs, revenues produced by these rates will generally exceed a utility's revenue requirement, resulting in utility earnings at a higher rate of return than that allowed by the PSC. To reduce revenues from marginal-cost-based rates to the level established by the PSC, the utility is forced to charge rates that are lower than estimated marginal costs.

Of the several methods developed to reduce revenues to the constrained revenue level, the best known method is the inverse elasticity rule, the use of which results in the greatest reduction in marginal-cost-based rates for those uses or customer groups with the least elastic demands. It is argued that production and consumption inefficiencies caused by deviations from marginal cost pricing will be minimized by following the inverse elasticity rule.

While we agree with the theoretical basis of the inverse elasticity rule, we also believe that deviation from marginal cost pricing should follow two ground rules:

1. Customer charges should be reduced, but not eliminated.
2. The ratio of peak to off-peak marginal kW and kWh costs should be maintained to the extent possible.

If these two ground rules are followed, the resulting TOD rates should provide proper price signals to customers regarding the true costs of providing electric service without allowing any customer at any time to receive service at no cost.

EVALUATION OF UTILITIES' MARGINAL-COST-BASED RATES

Both utilities submitted marginal-cost-based rates in response to the PSC's order. However, we were unable to assess Delmarva's rates, because no supporting data were submitted. BG&E did indicate the methods it used to develop the rates; consequently, we are able to make specific recommendations to BG&E. Our evaluations are presented in the remainder of this chapter.

Baltimore Gas and Electric Company

BG&E submitted two sets of marginal-cost-based TOD rates, each based on a different method for estimating revenue requirements. Both sets of marginal-cost-based rates produced excess revenues of \$230 million for the test period. In the first method (the method preferred by BG&E), BG&E set the adjusted revenue level from each rate schedule equal to the product of each schedule's unadjusted revenue and the ratio of total allowed revenue to total excess revenue (see Exhibit 5.a). In the second method, BG&E reduced the marginal-cost-based TOD rates to produce the level of revenue currently allowed from each rate schedule (see Exhibit 5.b). TOD rates developed using the first method are higher than TOD rates developed using the second method for Schedules R and T and lower for Schedule G.

Exhibit 5.a

BG&E

Summary of Marginal Cost Rates

Maintaining the Ratio of Marginal Costs Between Schedules

	Schedule R		Schedule G				Schedule T
	TOD	Non-TOD	60 kW Demand and Under		Over 60 kW Demand		TOD
			TOD	Non-TOD	TOD	Non-TOD	
Customer charge (\$/bill)	7.260	3.930	11.040	6.830	64.430	53.420	253.000
Demand charge (\$/kW)							
Peak *							
–Summer**	–	–	–	–	11.310	11.240	9.380
–Winter†	–	–	–	–	1.800	1.790	1.500
Off-peak‡							
–Summer	–	–	–	–	11.310	11.240	0.150
–Winter	–	–	–	–	1.800	1.790	0.150
Energy charge (¢/kWh)							
Peak							
–Summer	12.549	6.778	9.276	5.768	1.716	1.371	1.594
–Winter	3.923	2.496	3.235	2.288	1.681	1.396	1.561
Off-peak							
–Summer	1.263	6.778	1.232	5.768	0.970	1.371	0.902
–Winter	1.263	2.496	1.232	2.288	0.970	1.396	0.902

*8:00 a.m.-11:00 p.m. weekdays.

**Four billing months of June-September, inclusive

†Eight billing months of October-May, inclusive.

‡All hours not in "**".

Exhibit 5.b

BG&E

Summary of Marginal Cost Rates

Based on Case No. 7070 Revenue Allocation

	Schedule R		Schedule G				Schedule T
			60 kW Demand and Under		Over 60 kW Demand		
	TOD	Non-TOD	TOD	Non-TOD	TOD	Non-TOD	TOD
Customer charge (\$/bill)	7.260	3.930	11.040	6.830	64.430	53.420	253.000
Demand charge (\$/kW)							
Peak*							
–Summer**	–	–	–	–	13.950	13.870	9.180
–Winter†	–	–	–	–	2.220	2.210	1.470
Off-peak‡							
–Summer	–	–	–	–	13.950	13.870	0.150
–Winter	–	–	–	–	2.220	2.210	0.150
Energy charge (¢/kWh)							
Peak							
–Summer	10.714	5.786	11.622	7.226	2.119	1.693	1.555
–Winter	3.351	2.132	4.053	2.867	2.075	1.722	1.523
Off-peak							
–Summer	1.078	5.786	1.544	7.226	1.198	1.693	0.880
–Winter	1.078	2.132	1.544	2.867	1.198	1.722	0.880

*8:00 a.m.-11:00 p.m. weekdays.

**Four billing months of June-September, inclusive.

†Eight billing months of October-May, inclusive.

‡All hours not in "**".

To facilitate our examination of BG&E's marginal cost response, we focus on the TOD rates shown in Exhibit 5.a; however, our comments are also applicable to the TOD rates shown in Exhibit 5.b.*

On the basis of our examination of BG&E's marginal cost study and the methods used to develop the TOD rates for each rate schedule, we recommend that the PSC not require BG&E to implement the marginal cost rates at this time. We also recommend that BG&E continue to develop its marginal cost methodology and the methods used to translate marginal costs into rates.** Although the company's first effort in performing a marginal cost study should be recommended, certain refinements are necessary before BG&E's marginal-cost-based TOD rates can be implemented.

The design of BG&E's marginal-cost-based TOD rates is identical to BG&E's design of TOD rates based on accounting costs (see Exhibit 1.b in Chapter 1). As we mentioned in Chapter 1, BG&E should develop three-part TOD rates for Schedule R customers and Schedule G customers with demands of 60 kW or less. BG&E should also develop peak and off-peak demand charges for Schedule G customers with demands exceeding 60 kW and summer and winter off-peak energy charges for each rate schedule.

We disagree with BG&E's assumption that the marginal-cost-based TOD rates will produce a 10-percent decrease in kWh sales during the summer and winter peak periods for each rate schedule and a 10-percent decrease in billed kW during the peak periods for Schedule T. For TOD rates

* BG&E also submitted non-TOD rates based on marginal costs for Schedules R and G (see Exhibits 5.a and 5.b). The non-TOD rates include seasonal energy rate differentials for Schedule R customers and Schedule G customers with demands of 60 kW or less. Seasonal demand and energy rate differentials were developed for Schedule G customers with demands exceeding 60 kW.

** BG&E indicated that its marginal cost methodology is based on the methodology presented in National Economic Research Associates, Inc., How to Quantify Marginal Costs: Topic 4, prepared for the Electric Utility Rate Design Study, March 10, 1977.

based on accounting costs, BG&E assumed a 5-percent decrease in peak kWh sales and a 5-percent decrease in peak kW consumption by Schedule T customers (see Chapter 1). Because peak and off-peak price differentials are greater for rates based on marginal costs than for rates based on accounting costs, the company felt it necessary to assume the 10-percent kW and kWh sales decrease for reasons of financial protection. As stated in Chapter 1, BG&E assumed incorrectly that TOD rates would cause decreases in consumption during peak periods with no corresponding increase in off-peak consumption, i.e., that the cross-elasticity of demand between peak and off-peak rating periods is zero.

To evaluate the implication of this assumption, we compared BG&E's TOD rates based on accounting and marginal costs and the billing determinants used to calculate the revenues produced by each rate. The results of our analysis revealed that not only did BG&E explicitly assume that the cross-elasticity of demand between rating periods is zero, the company also implicitly assumed that the direct price elasticity of demand during the off-peak period is zero. For example, BG&E developed off-peak energy charges for Schedule R of 2.602 cents per kWh using accounting costs and 1.263 cents per kWh using marginal costs. However, in determining the off-peak revenues produced by these charges, BG&E assumed that the same number of kWh would be sold during the off-peak period at either price, i.e., that the price elasticity of demand during the off-peak period is zero. BG&E made the same assumption regarding off-peak kWh sales for Schedule G and also assumed that kW and kWh off-peak price elasticities for Schedule T were both equal to zero.

Even more questionable is BG&E's implicit assumption that the kWh price elasticity for Schedule R and kW price elasticity for Schedule T during the winter peak period are positive. In other words, BG&E assumes that increases in the Schedule R winter peak kWh rate and the Schedule T winter peak kW rate will cause an increase in kWh consumption by Schedule R customers and an increase in kW demand by Schedule T customers during the winter peak period. The Schedule R winter peak kWh rate based on accounting costs is 4.575 cents per kWh; the kWh rate based on marginal costs is 3.923 cents. However, BG&E, in determining the revenue produced by each rate, assumed that fewer kWh would be sold during the winter peak period at 3.923 cents per kWh than at 4.575 cents per kWh. In Schedule T, the

winter peak demand charge based on accounting costs is \$2.98 per kW, while the marginal cost rate is \$1.50. Once again, in calculating the revenue produced by each rate, BG&E assumed that Schedule T customers would demand fewer kW at \$1.50 per kW than at \$2.98.

We believe BG&E was not aware of the implications of its explicit and implicit assumptions concerning price elasticities. Therefore, while we recognize BG&E's desire to protect itself financially, we believe that the company should develop new marginal-cost-based rates using more logical assumptions concerning price elasticities.

As discussed in Chapter 1, we disagree with BG&E's use of the BIP method to allocate demand-related power supply costs based on accounting costs to rating periods. In the marginal cost study, BG&E used relative values of the loss of energy probability (LOEP) to allocate all demand-related plant costs (including distribution costs) to rating periods.* LOEP is the probability that during a specified time period BG&E will be unable to meet the energy demands on its system. Because LOEP is higher during peak hours than during off-peak hours, BG&E's use of LOEP results in the allocation of 76 percent of marginal demand-related unit costs for each rate schedule to the summer peak period, 22 percent to the winter peak period, and 2 percent to the off-peak periods. BG&E states that "the cost of system expansion should be apportioned to these hours in respect to the probability of (energy demands) exceeding capacity."** We agree with BG&E and therefore recommend that the company use the LOEP method, or a similar method, to allocate demand-related power supply costs in the accounting cost TOD study described in Chapter 1.

In light of the fact that the company had never before performed a marginal cost study, the methods used to calculate the marginal costs are relatively reasonable.

* BG&E, response to PSC Order No. 62568, Section C, p. 13.

** BG&E recognized that only demand-related power supply costs should be allocated using LOEP, but the company did not have sufficient data to develop a different method for allocating demand-related distribution costs.

However, to determine if the results of BG&E's study truly reflect the company's marginal cost of providing electric service, it would be necessary to examine such items as the company's:

- Load and sales forecasts through 1990
- Generating capacity expansion plans through 1995
- Planned reserve margins between 1978-1990
- Planned additions to transmission and distribution systems through 1990
- Historical load and sales data by customer group
- Operating arrangements with the Pennsylvania-New Jersey-Maryland (PJM) power pool
- Derivation of carrying charges
- Planned maintenance schedules and expected forced outage rates.

Although such an examination is outside the scope of this study, it should be undertaken prior to approving BG&E's proposed TOD rates based on marginal costs.

Delmarva Power & Light
Company of Maryland

Although Delmarva contends that marginal cost studies are artificial and unnecessary innovations in electric utility rate making,* the company did submit TOD rates based on marginal cost for residential customers and for general service customers receiving service at primary and secondary voltage levels (see Exhibit 5.c).

Because Delmarva failed to submit a marginal cost study or any explanation of the techniques used to develop these TOD rates, we are unable to make specific recommendations concerning Delmarva's marginal cost rates. The PSC should direct Delmarva to submit the marginal cost study that provides the basis for the rates submitted in the response and explain how these rates were developed.

* Delmarva, response to PSC Order No. 62568, p. 2.

Exhibit 5.c

**Delmarva
Adjusted Marginal Cost Rates**

	Peak* June-September	Peak* October-May	Off-Peak Year-Round
Primary general service			
Customer charge (\$/mo)	50.00	50.00	
Energy charge (¢/kWh)	0.75	1.40	0.25
Demand charge (\$/kW)	7.00	3.10	1.00
Secondary general service			
Customer charge (\$/mo) ¹	20.00	20.00	
Energy charge (¢/kWh)	0.77	1.44	0.25
Demand charge (\$/kW)	7.10	3.20	1.00
Residential service			
Customer charge (\$/mo)	5.00	5.00	
Energy charge (¢/kWh)	7.95	4.55	0.85

NOTE: These rates have been developed with a considerable degree of judgment in the absence of load data, especially in the area of individual customer coincidence. The A.J. Schultz 1976 cost of service study provided most of the determinants used. The present general service rate has been divided into a primary and secondary service rate format. The present High Tension rate has been incorporated into the primary general service rate. No marginal cost rates have been attempted for the small classes of area lighting and public authorities.

*Peak hours are from 8:00 a.m.-10:00 p.m., Mondays-Fridays.

6

TIME-OF-DAY USAGE EXPERIMENTS

As part of its investigation of electricity rates, the Maryland PSC ordered "that each electric company with gross annual revenues exceeding \$25,000,000 shall submit to the Commission, on or before January 1, 1978, their plans for the experimental testing of 200 large residential customers for time-of-day usage."*

The PSC subsequently indicated that, rather than actually offer TOD rates on an experimental basis to 200 residential customers, the utilities should submit their plans for conducting TOU load research on a sample of 200 residential customers. As the PSC did not specify what constitutes a "large" residential customer, the utilities had to make this determination when defining the sample to be used for the load research.

Although the PSC did not require the utilities to submit plans for actually conducting a TOD rate experiment on 200 large residential customers, we believe that an actual experiment would be more useful than simply collecting TOD usage data over a 12- to 18-month period. This rate experiment would provide the PSC and the utilities with valuable information on the potential effects of TOD rates.

We also believe that the PSC should reconsider its sample size requirement of 200 customers. Determination of sample size for either a TOD usage or TOD rate experiment should depend on the statistical properties (i.e., mean and variance of kWh usage and kW demands) of the residential population. If the required sample size were determined using statistical sampling techniques, the PSC and the utilities could find that a sample size of 200 customers is either too large or too small to provide

* Maryland PSC, Case No. 6808, Order No. 62568, p. 4.

statistically reliable estimates of the demand characteristics of large residential customers. For example, if statistically reliable results could be obtained from a sample of 100 customers, the utility and its customers would benefit by saving the resources that would have been used to sample 100 additional customers. If a sample size greater than 200 customers were required to obtain statistically reliable results, the PSC should ensure that the utility increases the sample size to the appropriate level.

As stated in Chapter 1, TOD rates should be implemented where practical. To design and analyze TOD and other TOU rates, the utility must know the customers' demand patterns. Furthermore, where additional metering is required, the utility should estimate the probable effects of these rates on these patterns to ensure that the benefits of TOD rates will be greater than the costs. Load research is the means by which the necessary data are collected. Generally, less information is available on residential customers, who, unlike commercial and industrial customers, do not have demand meters. Although small residential users may be able to alter their demand patterns, the costs of implementing TOD rates for such customers will probably offset any benefits (see Chapter 1). Consequently, the PSC is focusing on the need to collect load research data on large residential customers.

Because we recommend the use of TOD rates as the most effective means of increasing consumption and production efficiency, we support the undertaking of load research studies. Moreover, regardless of the pricing policy changes or load management programs selected by the Maryland PSC, load research data are necessary to develop an effective program designed to increase production and consumption efficiency.

The requirements of a load research program and our evaluation of the utilities' responses to the PSC order are given in the following two sections.

REQUIREMENTS FOR CONDUCTING LOAD RESEARCH STUDIES

To conduct load research for designing TOD rates, the following steps are required:

1. Identify the data to be collected
2. Select and verify the sample
3. Identify and install the necessary equipment
4. Conduct customer surveys
5. Analyze data using computers.

Each step is described in the remainder of this section.

Designing TOD rates requires energy-use data by customer, demand data by customer, coincident and noncoincident maximum demand data by customer group, load factor data, diversity factor data, and daily load curves for the system and individual customer groups. Information on the probable response of residential customers to TOD rates is also useful.

Once the purpose of the load research study and the associated data needs are identified, the utility should select and verify the sample. In this effort, the utility must specify the size of the residential customers who will be subject to the TOU experiment, select a sample from this specific population using either a judgmental or probabilistic sampling technique, and verify that the sample is indeed representative of the population.

Within the categories of judgmental and probabilistic techniques, there are many different sampling procedures and verification tests.* We recommend the use of probability techniques for selecting samples, as such techniques are likely to be more accurate than subjective

* See, for example, J.J. Doran et al., 1973, pp. 15-18.

techniques. For the residential customer class, a statistically representative sample can be obtained from a random sample of large residential customers or from a sample stratified according to annual energy-use levels or appliance stock.

Statistical methods can also be used to choose the size of the sample. However, because the PSC ordered the experimental testing of 200 residential customers, sample size is not a variable in this study.*

To collect TOU data on residential customers, additional metering and other equipment is generally necessary. For large volumes of data, magnetic tape recorders are preferable, because they facilitate information translation. If the meters are not currently available, at least 200 of these meters should be purchased and tested, so they can be installed and operated before the start of the load study. In this manner, any malfunctions or installation problems can be identified and corrected. Other necessary equipment, such as translators and readers, should also be installed prior to undertaking the study.

Data on the probable response of customers to TOD rates can be obtained through customer surveys of household appliance stocks and life-styles (e.g., family size, income, number of children under age 6, and number of household members at home during the day). Such information is also indicative of consumer demand elasticities. Surveys can be conducted through written questionnaires or personal interviews.

Computers should be used to analyze the data. The utility should review its existing computer equipment and programs to ensure that they are suitable. Data-handling programs can be purchased (e.g., from IBM) or developed internally. At least 12 consecutive months of load and usage data should be collected and analyzed before using the data to design and implement TOD rates.

* As mentioned previously, sample size should be determined by the statistical properties of the population to be sampled. Therefore, the PSC should reconsider the required size of 200.

EVALUATION OF UTILITIES' RESPONSES

Although both utilities addressed the issue of load research, only BG&E proposed a study that met the requirements as described in the previous section. Our evaluation of the utilities' responses and recommendations regarding next steps are given below.

Baltimore Gas and Electric Company

In its response, BG&E clearly identifies the scope of the load research study required by the PSC order. In the BG&E proposed study, the test population was defined as those 14,975 residential customers who consumed 2,500 kWh or more in the billing month of July 1977. BG&E does not explain its reason for selecting 2,500 kWh as the cutoff point for large residential customers.

The sample representing this population was selected by reordering the population records and then applying a systematic sampling technique (a modified form of random sampling). Specifically, the master records of the test population were reordered by company district, then by billing section within each district, and finally by account number within each section. After this reordering, the master records were renumbered, and, starting from a random point, every 75th record was selected to create a systematic sample of 200 customers. A second backup sample was selected in the same manner. In its response, BG&E supports the sample selected with several statistical tests (t-tests, analyses of bill frequency distributions, and percent distribution by company district). These tests fully validate both the primary and backup samples.

BG&E proposes to use magnetic tape demand recorders that record total load requirements every 15 minutes. The average cost of equipment and installation is given as \$600 per location. The company proposes to conduct the load research study for at least 1 year and to store and process the collected data on its IBM 360/65 computer.

BG&E's approach to a load research study is correct, but it could be improved by including customer surveys designed to elicit probable responses to TOD rates.

Such information (e.g., household appliance stock and household life-styles) can be valuable in ascertaining potential benefits of TOD rates. In addition, BG&E's response does not specify how the analysis will be conducted and the results used. The PSC should require BG&E to include customer surveys in its proposed study and to explain how it will analyze and use the load research data.

Delmarva Power & Light
Company of Maryland

Although Delmarva properly recognizes that sufficient load research data are necessary before initiating any change in rate design (specifically, before designing and implementing TOD rates), Delmarva's response does not address the different requirements of load research described previously.

Currently, Delmarva uses magnetic tape recorders to collect billing data for 200 large commercial and industrial customers and load research data for 160 randomly selected residential customers (of the latter, 53 are in Maryland). Delmarva plans to relocate the 160 residential meters after 1 year, but it is not clear if Delmarva intends to install all of the 160 meters in Maryland. At a minimum, Delmarva intends to collect load research data using the 53 meters that have been installed in Maryland since June 1977.

Delmarva does not specify how it intends to meet any of the specific requirements of the residential TOU study. Before any decision can be made regarding the validity of Delmarva's proposed study, Delmarva must:

1. Identify the data needs of the study
2. Indicate the size and the rationale behind the specified size of the residential customers it intends to sample
3. Demonstrate that these customers are representative of the population being sampled, and that it is not necessary to have a sample size of 200, as requested by the PSC
4. Specify how the data will be analyzed
5. Specify how the data will be used.

7 LOAD MANAGEMENT PROGRAMS

In addition to alternative rate structures, the Maryland PSC is investigating load management programs as a means of increasing energy production and consumption efficiency. As part of this investigation, the Maryland PSC ordered "that each electric company, with gross annual revenues exceeding \$25,000,000, shall file with the Commission, on or before January 1, 1978, a summary of its plans for load management that it believes practical and that will reduce the future need for new facilities."*

Load management is a general term used to describe direct and indirect activities designed to reduce electric loads during certain periods and shift electric loads from one time period to another. We recommend that the PSC require the utilities to implement the relatively inexpensive indirect load management programs (e.g., promoting installation of insulation in homes). At the same time, the PSC should evaluate the feasibility and costs and benefits of the more expensive indirect (e.g., energy storage) and direct (e.g., radio and ripple switching programs) load management programs.

Load management programs complement, rather than substitute for, TOU pricing programs. Customers who wish to reduce their consumption during peak periods because of higher peak rates will be encouraged to install direct, on-site load control equipment (e.g., appliance interlock devices) to achieve a reduction. Load management, as a complement of pricing policy changes (i.e., TOU rates), can reduce a utility's need for additional generating capacity and promote the efficient utilization of a utility's existing plant.

In the remainder of this chapter, we describe the requirements of direct and indirect load management programs and evaluate the utilities' responses regarding their existing and proposed programs.

* Maryland PSC, Case No. 6808, Order No. 62568, p. 4.

(particularly ripple control systems) have been used extensively and successfully by utility systems in Europe, Africa, and New Zealand to improve load factors and reduce the need for generating capacity. Several utilities in the United States are currently testing one-way and two-way direct load control systems to determine the systems' effects on peak demands, load diversity, and billing expenses. For example, since January 1, 1976, Central Vermont Public Service Corporation has used a one-way ripple system to control loads, such as space and water heating. The Detroit Edison Company has used radio signals to control water-heating loads since the late 1960s. Wisconsin Electric Power Company has installed 450 automatic meter-reading units that provide remote control of any two loads and remote meter reading for a two-part tariff (i.e., a rate with separately stated kW and kWh charges).

Because direct load control (particularly remote control) has not been used extensively in this country, we recommend that the PSC require the utilities to perform cost-benefit studies of remote load control options before implementing comprehensive load management programs. Interruptible rates should be implemented at this time, as the implementation costs are minimal.

Indirect Load Management Programs

The second category of options consists of activities that encourage or enable a customer to conserve energy by reducing electricity consumption. These activities include promoting the installation of additional insulation in homes, the purchase of energy-efficient appliances, and the purchase and installation of energy-storage devices; informing customers about inexpensive ways to reduce their electric bills by reducing consumption; and developing special electric rates available only to customers whose homes or places of business meet specified energy-efficiency standards.* By educating

* Duke Power Company, for example, has recently been granted permission from the North Carolina Utilities Commission to implement a residential conservation rate that is available only to customers whose homes meet very stringent energy-efficiency standards.

customers about the potential benefits of energy conservation and offering customers incentives to conserve energy, utilities can provide a valuable service to ratepayers, as well as increase their load factors and reduce the need for additional generating capacity.

Because most indirect load management options are relatively inexpensive, the PSC should encourage the utilities to undertake these options.

EVALUATION OF UTILITIES' PROPOSED AND EXISTING LOAD MANAGEMENT PROGRAMS

Both BG&E and Delmarva have plans to develop direct and indirect load management programs. A description of these plans and recommended next steps are given in the following subsections.

Baltimore Gas and Electric Company

BG&E defines load management as "the concept of altering a pattern of electricity use in order (1) to improve the load factor, (2) to reduce the load at the time of a daily, weekly, monthly, or yearly peak demand, and ultimately (3) to reduce generating capacity requirements."*

The company's response covers four direct and indirect load management activities, of which three are still in the planning stages. BG&E plans to offer a curtailable rider (interruptible service) on contracts to large industrial and commercial customers, raise the minimum acceptable power factor for customers to reduce peak demands, and build a pumped storage hydroelectric facility, in which water will be stored for use in operating turbines during peak demand periods. Currently,

* BG&E, response to Order No. 62568 in PSC Case No. 6808, December 1977, p. G:7-1.

the company provides demand pulse information or equipment to customers wishing to install their own load management equipment.

In addition to these four activities, BG&E participates or has participated in several other programs. First, as part of the National Energy Watch (NEW) program, sponsored by the Edison Electric Institute, BG&E certifies new homes that meet the company's energy-efficiency standards. In this manner, BG&E encourages contractors to build energy-efficient houses. Also, some BG&E customers have installed the IBM System 7, a computer program enabling industrial and commercial customers to control and rotate their own loads. The 70 customers currently using this system and the 5 customers either in the process of planning for its use or installing it are indicative of the willingness of customers to implement load management systems. Finally, a residential attic insulation program sponsored by BG&E was abolished in November 1977 because of shortages of insulation material. In this program, BG&E assisted customers in determining the type and amount of insulation that should be added to their attics, financed the installation of the insulation by a contractor selected by BG&E, and retrieved the cost of the insulation through monthly customer billings.

Several improvements can be made in BG&E's three planned load management programs:

1. BG&E should develop indirect load management programs to promote conservation. In this effort, customer education programs, residential conservation rates, and the reestablishment of the attic insulation program should be encouraged.
2. BG&E should seek approval from the Maryland PSC to implement its planned curtailable rider for large industrial and commercial customers. Prospective customers with potentially interruptible loads should be identified and encouraged to take advantage of the interruptible service.
3. BG&E should provide the PSC with information on the economics of the pumped storage hydroelectric facility mentioned in its response. Although a pumped storage facility is actually part of a generating capacity expansion plan, rather than a load management

program, pumped storage facilities can enable a utility to provide electricity during peak periods at less cost than conventional peaking turbines and to utilize its baseload capacity more efficiently.

Delmarva Power & Light
Company of Maryland

Delmarva's response to the PSC's request for information on the company's load management plans mentioned 12 load management programs.* However, explanations of the programs were not provided, and the status (i.e., active, inactive, planned) of each program was not identified.

Delmarva's load management plans combine direct and indirect load management programs.** Direct program plans include expansion of interruptible Rate Q, installation of an automatic meter-reading and control (AMRAC) system, and establishment of cogeneration and wholesale power policies. Delmarva can interrupt 120 megawatts (MW) of load created by customers served under Rate Q. These loads are interrupted an average of eight times per year, or whenever a new system peak is likely to occur. According to company officials, Delmarva will install the AMRAC system, which enables a utility to control loads and obtain metering readings from a remote location, only if the PSC orders mandatory load management. Finally, the cogeneration and wholesale power policies are designed to reduce Delmarva's need for generating capacity and to promote energy conservation.

The company's indirect load management programs consist of the promotion of heat pumps as energy-efficient heating equipment; an advertising program for conservation; an energy-efficiency award program for new homes

* Delmarva, response to Order No. 62568 in PSC Case No. 6808, p. 8.

** Delmarva includes TOD rates in its load management plans. We consider TOD rates complements, rather than integral parts, of load management programs. Delmarva's TOD rates are discussed in Chapter 1.

constructed according to Delmarva's energy-efficiency standards; and a customer consultation program designed to explain the benefits of insulation to residential customers. The company also plans to promote customer-owned appliance interruptors and interlock devices when TOD rates are implemented. In addition, Delmarva funded a 1-year study of various solar water-heating systems and is providing \$60,000 to support research on thermal storage devices at the University of Delaware Institute for Energy Conservation. The company is also evaluating the sales and service market for solar appliances.

Delmarva's load management plans appear to be extensive, yet prudent. Because Delmarva did not describe these programs in great detail, the PSC should request additional information regarding the status of the 12 programs mentioned and the extent to which the company's indirect load management programs are being made available to customers in Maryland. Finally, the company should provide the PSC with estimates of the potential benefits of installing an AMRAC system.