APPROACH FOR CONSIDERING SELECTED RATEMAKING STANDARDS OF PURPA

prepared for

THE OKLAHOMA CORPORATION COMMISSION

by

RESOURCE PLANNING ASSOCIATES, INC.

in behalf of

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

OCTOBER 1979

FOREWORD

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

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

The NRRI appreciates the cooperation of the Oklahoma Corporation Commission with the authors in preparing this study.

Dr. Douglas N. Jones
Director

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TASK 6

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U. S. DEPARTMENT OF ENERGY
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Exhibits

Introduction

In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), Title I of which establishes federal ratemaking and regulatory standards, lifeline rate guidelines, and cost-of-service data requirements. The federal ratemaking standards address cost of service, load management techniques (including interruptible rates), and declining block, time-of-day (TOD), and seasonal rates. These standards, as well as the other provisions of Title I, were established to promote three objectives: the conservation of electricity by customers, the efficient use of facilities and resources by electric utilities, and the provision of equitable rates to customers.

Under the provisions of Title I, state regulatory authorities and nonregulated utilities are required to complete a formal consideration of these ratemaking standards by 1981 and determine if they (1) promote conservation, efficiency, and equity, and (2) are consistent with state law. As part of this formal consideration, the regulatory authorities are required to hold hearings on these standards. Such hearings can either be on a case-by-case basis as part of general rate cases or be evidentiary, generic hearings.

To meet its obligations under PURPA, the Oklahoma Corporation Commission (OCC), with the assistance of the National Energy Law and Policy Institute (NELPI), has applied for a technical assistance grant from the U.S. Department of Energy (DOE) under the PURPA Grant Program. However, grants will not be available until October 1, 1979. Because OCC must decide on whether or not to implement the PURPA standards by 1981, the commission requested that the National Regulatory Research Institute (NRRI) provide technical assistance so that OCC can begin to consider each of the ratemaking standards as soon as possible.

As a first step in providing this assistance, NRRI retained Resource Planning Associates, Inc. (RPA), to develop guidelines and recommend steps that OCC could follow to meet its obligation to consider three of PURPA's ratemaking standards: cost of service, declining block rates, and seasonal rates.

It is important to note that, although PURPA language designates cost of service as a ratemaking standard along with declining block, TOD, seasonal, and interruptible rates, cost-based rates, not cost-of-service studies, are the means by which PURPA's objectives of conservation, efficiency, and equity can be achieved. However, cost-of-service studies are required to design cost-based rates. Therefore, it is not possible to evaluate either the cost-of-service standard or any rate types independently.

A cost-of-service study allocates the utility's total costs to each jurisdiction or customer group within a jurisdiction according to the actual costs of providing electricity to that jurisdiction or group. Rates based on cost-of-service study results will represent a significant step toward meeting PURPA's objectives of conservation, efficiency, and equity. First, because cost-based rates reflect, to the greatest extent possible, the true costs of providing utility services, and, as such, will increase as these costs increase, consumers will be motivated to conserve electricity (and, hence, the fuels used to generate that electricity). Second, efficient electricity production will be indirectly encouraged because a major goal of utility regulation is to ensure least cost construction, investment, and fuel purchase by utilities. To justify and design cost-based rates, regulators will have to examine closely the utilities' rate bases and expenses (which are identified in cost-of-service studies), resulting in identification of any inefficient production. Finally, rates will be equitable if customer groups are charged on the basis of cost of service reflecting the customers' relative demands on the system, consumption, and need for related services.

Consequently, rather than addressing the need for cost-of-service studies, RPA focused its evaluation of this standard on identifying the major methodological issues concerning cost of service and recommending steps that OCC should take to implement the standard. In addition, we recommended a standard accounting cost-of-service methodology that we believe will result in the most accurate allocation of costs to retail customer groups in Oklahoma. We also identified ratemaking issues that OCC should address in considering the declining block and seasonal rate standards, once the cost-of-service standard has been implemented. Finally, we reviewed the 1978-test-year cost-of-service study and proposed retail rates filed by Oklahoma Gas and Electric Company (OG&E) in its recent retail rate case before the OCC (Cause No. 26495). In this review, we identified the methods used by OG&E to address the key cost-of-service methodological issues and attempted to determine if OG&E's proposed declining block and seasonal rates were justified on the basis of the cost-of-service study results, seasonal load forecasts, and operating practices. We also identified the data deficiencies that OCC must address when considering the cost-of-service standard and declining block and seasonal rates.

We summarize our recommendations below:

- To expedite implementation of the cost-of-service standard, and, hence, allow consideration of the other ratemaking standards by 1981, OCC should conduct formal, generic hearings. These hearings will serve two purposes:
  - Identify an acceptable standard cost-of-service methodology for the four utilities within OCC's jurisdiction.[1] We have recommended an accounting cost-of-service methodology that should be presented for consideration in these hearings and modified as necessary to be practical for the four utilities.[2]

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1. Four investor-owned electric utilities under OCC's jurisdiction are covered by the provisions of PURPA: OG&E, Empire District Electric Cooperative, Public Service Company of Oklahoma, and Southwestern Public Service Company.

2. It is important to note that implementation of an accounting-cost-based cost-of-service study is only a first step in setting cost-of-service requirements. Once all of the PURPA standards have been formally considered, OCC should hold generic hearings to discuss the appropriateness of using accounting versus marginal costs to design rates.

Although OCC typically requires large utilities to file cost-of-service studies as part of general rate cases, OCC has not yet adopted a standard methodology for these studies, nor has it standardized the use of these studies in setting rates. These hearings should focus on resolving the major methodological issues that we identified (e.g., how should demand-related generation and transmission costs be allocated to customer groups?)

- Develop a timetable for implementing this standard that will allow OCC to consider the other ratemaking standards by 1981.

- To ensure that the Oklahoma utilities can perform accurate cost-of-service studies, OCC should require the utilities to upgrade and expand their load research programs. Comprehensive load research data will also allow OCC to consider the seasonal, declining block, and other rate forms in light of PURPA's objectives. Our review of OG&E's cost-of-service study and discussions with OCC personnel indicate that OG&E's load research program, and probably those of the other three utilities, will have to be expanded rapidly for the OCC to meet PURPA's requirements. OCC should identify the requirements of the utilities' load research programs and establish a timetable for each of the utilities to meet these requirements.

- To determine the effects of and cost-justification for declining block and seasonal rates, OCC should address, on a utility-specific basis, the ratemaking issues identified in this report. In addition, OCC should require the Oklahoma utilities to submit cost-of-service studies based on the standard methodology selected by the commission. Finally, OCC should require the utilities to submit any additional data (e.g., seasonal peak load forecasts, operating costs by time of use) needed to consider the appropriateness of seasonal and declining block rates.

In Chapter 1, we describe our recommended accounting cost-of-service methodology and compare it to alternative methodologies. We also highlight those cost-of-service methodological issues that OCC will need to resolve during its generic hearings. In Chapter 2, we discuss how, once the utilities' service costs have been properly allocated to jurisdictions and customer groups and adequate load research data have been developed, OCC can consider seasonal and declining block rates relative to PURPA's objectives. Finally, in Appendixes A and B, respectively, we review OG&E's cost-of-service study and proposed retail rates submitted in OCC Cause No. 26495.

1 COST-OF-SERVICE STANDARD

As required by Section 111 of PURPA, OCC must formally determine the appropriateness of the federal cost-of-service standard in terms of meeting PURPA's stated objectives of conservation, efficiency, and equity, as well as consistency with Oklahoma statutes. In other words, unless OCC determines that cost-of-service studies conflict with state laws or do not support PURPA's goals, the commission must ensure that retail rates charged by the electric utilities under its jurisdiction are designed to reflect the costs of providing service to each customer group.

RPA was retained by NRRI to assist OCC in considering the federal cost-of-service standard relative to its ability to meet PURPA's three goals. Because, as we explain below, conducting an accurate cost-of-service study is a necessary first step for both meeting PURPA's stated goals and considering the other federal ratemaking standards, we focus our discussion of this standard on selecting an appropriate cost-of-service methodology from the many methodologies available. We also highlight those major methodological issues that OCC must resolve prior to adopting a standard cost-of-service methodology.

A cost-of-service study is a fundamental requirement in designing cost-based rates, which, in turn, either directly or indirectly promote PURPA's objectives of conservation, efficiency, and equity in the following manner:

- Consumers will be motivated to conserve electricity because cost-based rates reflect, to the greatest extent possible, the true costs of providing utility services and, as such, will increase as service costs increase.

- Efficient electricity production will be indirectly encouraged because a major goal of utility regulation is to ensure least cost construction, investment, and fuel purchase by utilities. To justify and design cost-based rates, regulators will have to examine closely the utilities' rate bases and expenses to ensure that these least cost criteria are met, resulting in identification of any inefficient production.

- Equitable rates will be promoted because customer groups will be charged on the basis of cost of service, reflecting their relative demand on the system, electricity consumption, and need for related services.

Because cost-based rates are designed using the results of cost-of-service studies and customer billing data, OCC cannot consider whether the various rate forms given as PURPA standards (e.g., declining block, seasonal, TOD, interruptible rates) meet PURPA's goals until each utility has performed an accurate cost-of-service study. The applicability of the rate forms must be determined on a utility-specific basis, as discussed in Chapter 2 of this report. The need for valid cost-of-service studies, on the other hand, is not utility-specific. Therefore, in order that OCC may meet its obligations to consider PURPA's other standards by 1981, it should begin immediately to identify and adopt an appropriate, standard cost-of-service methodology.

By adopting a standard methodology for assigning cost-responsibility to customer groups, OCC can ensure that: similar customer groups served by different utilities are assigned cost-responsibility in an equitable manner, and customers served by each utility in the state are charged equitable rates that promote conservation of electricity and natural gas. For example, assume that: (1) two utilities with identical systems serve identical customer groups; (2) the rate of return on total rate base allowed by OCC is the same for each utility; and (3) OCC desires to set revenue requirements and rates for each group so that the rate of return from serving each group is the same for both utilities. If the utilities use different cost-of-service methodologies to allocate costs, the revenue requirements necessary to produce identical rates of return from similar customer groups will be different for similar customer groups served by each utility.

When selecting a standard cost-of-service methodology, many issues, both major and minor in nature, arise.

PURPA addressed several of these issues in Section 115(a), which states that, to the maximum extent practicable, a cost-of-service methodology must permit identification of cost differentials by time of use (i.e., seasonal and daily cost differentials) for each customer group. The methodology must also identify the demand-, energy-, and customer-related components of the costs of serving each customer or jurisdictional group. Finally, Section 115(a) implies the use of a marginal cost methodology to identify cost differentials by time of use. However, the language of the legislation also implicitly approves the use of an accounting cost-of-service study to identify demand-, energy-, and customer-related costs.

As stated previously, OCC must consider the PURPA regulatory and ratemaking standards by 1981. Therefore, we recommend that, as a first step in meeting its obligations, OCC concentrate on selecting and adopting an accounting cost-of-service study methodology. Our recommendation is based on the following:

- Utilities and regulatory institutions are already familiar with accounting-cost-based methodologies
- The issues related to embedded costs are clearer, more easily understood, and, hence, more easily and expeditiously resolved
- An accounting cost-of-service study can provide reasonable estimates of each customer group's cost-responsibility for a utility's past and current investments and expenses.

The accounting cost-of-service study must enable identification of demand-, energy-, and customer-related cost components. At a later point in time, OCC can address the issue of whether marginal- or accounting-cost-based methodologies should be use to identify time-of-use cost differentials.

Consequently, we have recommended a standard accounting-cost-based methodology for consideration by OCC. This methodology involves five steps:

1. Select a test period
2. Assign costs to functions
3. Classify costs within functions

4. Allocate costs to regulatory jurisdictional groups

5. Allocate costs to customer groups.

To ensure that our recommended methodology is applicable to the four utilities under OCC's jurisdiction, OCC should hold generic hearings designed to (1) gather evidence on the methodology's applicability and (2) resolve the major issues related to a cost-of-service methodology. These four issues relate to the:

1. Use of future as well as historic test years for determining revenue requirements.

2. Classification of distribution system costs into demand- and customer-related components.

3. Allocation of demand-related production, transmission, and distribution costs to jurisdictional and customer groups.

4. Need to upgrade load research programs. The usefulness of a cost-of-service study in assigning cost responsibility and developing rates depends not only on the methodology used to perform the study, but on the reliability of the data used in the study.

The detailed justifications for our recommendations pertaining to the cost-of-service standard are given in the remainder of this chapter, which is organized according to the five steps in our proposed methodology. Because those utilities serving customers in more than one state regulatory jurisdiction or serving wholesale as well as retail customers must allocate costs among regulatory jurisdictions prior to allocating costs to specific customer groups, we specify, within the steps, how to allocate costs to jurisdictions. In Appendix A, a case study of OG&E's 1978-test-year cost-of-service study, we show how one utility under OCC's jurisdiction has attempted to resolve the four major issues delineated above.

SELECT A TEST PERIOD

The test period is the time period for which costs will be estimated. Usually encompassing 12 months, it is called a "test year." An historical test year (e.g., the 12 months ending December 31, 1978) or a future test year (e.g., the year 1980) may be selected. Calculating costs for a future test year requires forecasts of investments, expenses, loads, sales, and customers.

We recommend that cost-of-service studies to be used in general rate case proceedings be performed for both historical and future test years. Although the analysis for a future test year is based on more uncertain data (e.g., expense forecasts), failure to assess the potential future impacts of rate decisions can adversely affect a utility's earnings and the revenues obtained from each customer's group.

Therefore, we recommend that OCC consider amending Section 2.30 of its minimum standard filing requirements to require the use of future as well as historical test years in electric utility cost-of-service studies. Even if OCC continues to establish revenue requirements and set rates using historical test year data, this approach will enable OCC to evaluate the effects of its decisions using future test year data. We believe that such an approach would be beneficial to both consumers and the utilities' stockholders.

ASSIGN COSTS TO FUNCTIONS

The first major step in calculating cost of service to each customer group is to assign a utility's costs to either the generation, transmission, distribution, or general function. Basically, the specific costs are assigned as follows:

Generation	Transmission	Distribution	General
Generating electricity Purchasing power from another system Delivering power to the bulk transmission system	Transferring power from generation sources to load centers within service areas or to or from other utilities	Transferring power from the transmission system to consumers	Plant investment or expenses not directly related to any other function (e.g., sales promotion, administration)

Depending on the technical configuration of the utility's system, further disaggregation of costs into subfunctions may be desirable for a more precise allocation to customer groups. For example, distribution costs could be disaggregated into primary and secondary distribution costs according to voltage service level.

To ensure that the Oklahoma utilities assign costs by function in a proper and consistent manner, we recommend that OCC revise its minimum standard filing requirements to specify the use of the Federal Energy Regulatory Commission (FERC), Uniform Systems of Accounts Prescribed for Public Utilities and Licensees, which is currently used by some Oklahoma utilities (e.g., OG&E).

In addition, OCC should use the National Association of Regulatory Commissioners (NARUC) cost allocation manual and the proceedings of the Edison Electric Institute (EEI) to develop a suitable method for applying the selected system of accounts.[1] Both of these documents detail the costs assigned to each major function (e.g., generation, transmission, distribution) and the rationale behind these assignments. Costs that are identified as not being directly related to these three functions should be assigned to the general cost function.

Finally, some costs (e.g., the costs of special facilities built to serve a particular customer) are not classified by function; instead they are assigned directly to a customer.

CLASSIFY COSTS WITHIN FUNCTIONS

As illustrated in Exhibit 1.a, the costs assigned to each function must be further classified as being one or more of the following:

Demand-related. Demand-related costs are the fixed costs of meeting customer demands (e.g., the cost of

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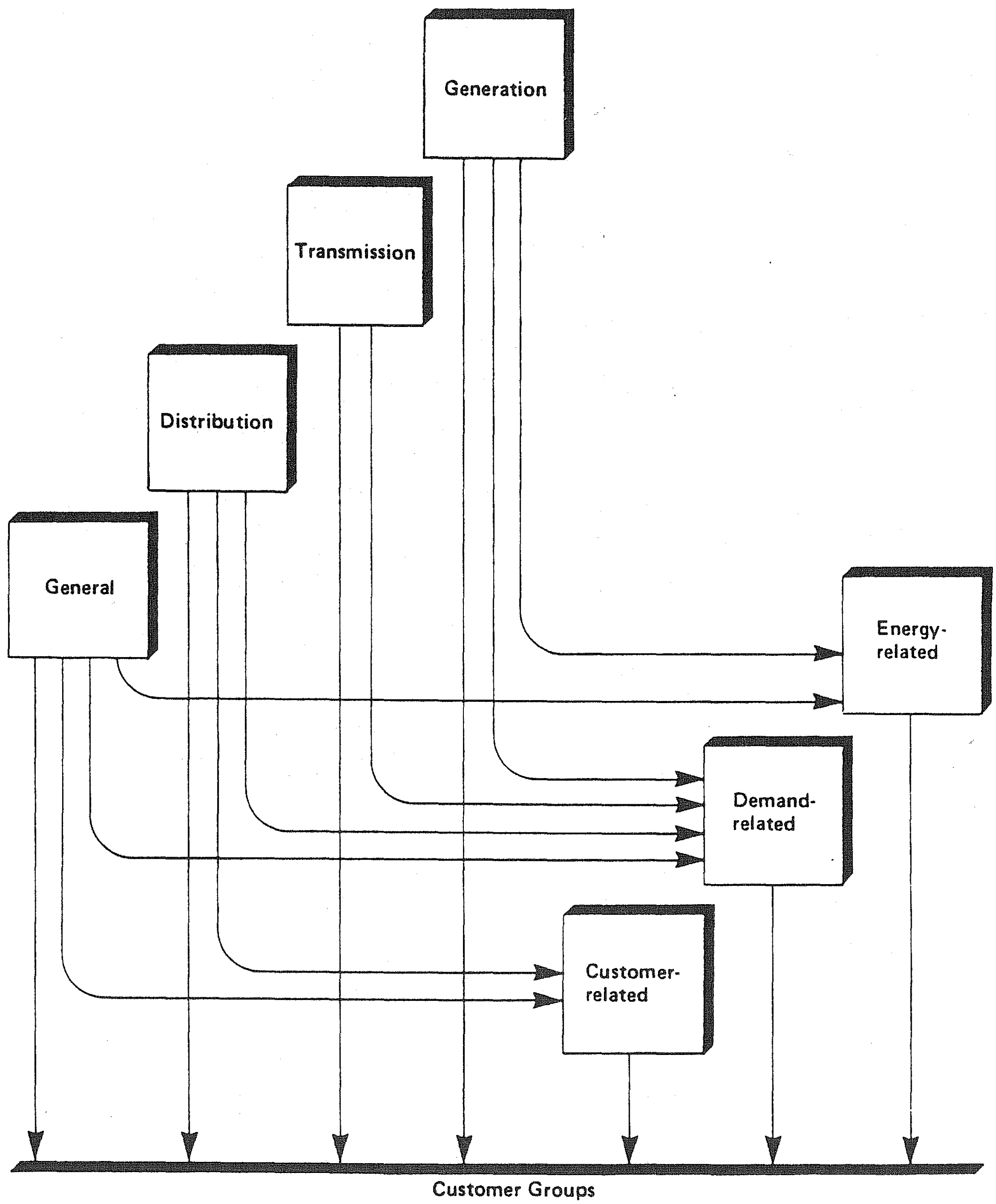
1. EEI, Cost-of-Service Symposium, September 21-23, 1970; and J.J. Doran et al., Electric Utility Cost Allocation Manual, NARUC, Washington, D.C., 1973.

Exhibit 1.a

Distribution of Total System Costs



transmission facilities). These costs are a function of the kilowatts (kW) of demand imposed on the generation, transmission, and distribution segments of the utility's system.

Energy-related. Energy-related costs are the costs of operating facilities to meet customer energy requirements (e.g., fuel costs). They are a function of the kilowatt-hours (kWh) produced to serve customer groups.

Customer-related. Customer-related costs are the costs of providing customer services; as such, they are a function of the number of customers served by a utility. Customer-related costs include portions of the distribution investment, as well as meter equipment, meter reading, and billing expenses.

To classify costs within functions, we recommend that OCC use the methods described in the NARUC cost allocation manual and the proceedings of the EEI cost-of-service symposium. When first allocating costs to jurisdictions, all costs within the generation and transmission functions (i.e., bulk power supply) are classified. Generally, all distribution costs are assigned directly to the jurisdiction served by the distribution facilities; as such, these jurisdictional costs are not classified within the distribution function. General function costs associated with serving customers in a specific jurisdiction are directly assigned to that jurisdiction; general function costs associated with serving all customers (e.g., customer accounting and sales expenses) are classified and then allocated to jurisdictions using appropriate allocation factors. To allocate costs to customer groups within a jurisdiction, all of the assigned costs within each of the major functions must be classified.

As described in the following paragraphs, the classification of generation, transmission, and general costs is relatively straightforward. However, the classification of distribution costs is more complex. In fact, one of the major methodological issues related to a cost-of-service study is the classification of distribution system costs into their demand- and customer-related components. Consequently, we focus our discussion of cost classification within functions on this issue.

Generation costs can usually be classified as demand- and energy-related to reflect the fixed (i.e., annual carrying costs of generating units) and variable (e.g., fuel) components of generation investments and expenses. Transmission costs are classified as demand-related because a transmission system is specifically designed to meet peak loads (i.e., it constitutes a fixed cost). General function costs can be classified into one, two, or all three categories. For example, general costs, such as customer accounting expenses, can be classified as customer-related; general plant investments can be divided among the demand-, energy-, and customer-related categories.

Distribution costs are divided between the demand- and customer-related categories. For example, the need for line transformers is a function of both the number of customers served and their peak demand. Those costs of the distribution system incurred in meeting maximum customer group demands (i.e., costs that vary according to maximum kW demand) are classified as demand-related; the costs of distribution facilities required to connect customers to the utility system (i.e., costs that vary according to the number of customers served) are classified as customer-related.

There are two methods for estimating the customer-related portion of distribution costs: the minimum-size method and the zero-intercept method (see the NARUC cost allocation manual, pages 56-71, for details). The ultimate distribution of costs among customer groups, and hence each group's revenue requirement, will depend on the method used.

Under the minimum-size method, distribution costs for nominal service to meet customer loads are estimated based on the average book value or current cost of the smallest distribution equipment installed in the system. For example, the customer-related component of distribution costs under the minimum-size method is the cost of minimum-size equipment in such accounts as poles, conductors, cables, and line transformers. The remaining distribution costs in these accounts are classified as demand-related.

The zero-intercept method involves the use of regression techniques to estimate the distribution costs of serving a hypothetical load of zero kW or amperes. The cost of meeting the zero-intercept load is the customer-related component of total distribution costs, and the remaining costs form the demand-related component. For example, when applying the zero-intercept method to determine the customer-related component of line transformers (i.e., FERC account 368), the installed book cost for transformer by size and voltage is regressed on the number of line transformers up to a size of 50 kilovolt-amperes. The intercept coefficient estimated in this regression is then multiplied by the number of transformers to derive the customer-related component of costs included in the line transformer account; the remaining costs in this account are classified as demand-related costs. This procedure is followed for each cost account included in the distribution function.

In general, the zero-intercept method produces relatively smaller customer-related and larger demand-related cost estimates than the minimum-size method. Because statistical relationships between the customer and demand components of distribution costs are established when the zero-intercept method is used, we recommend the use of this method.

ALLOCATE COSTS TO REGULATORY JURISDICTIONAL GROUPS

As stated in the previous section, when assigning costs to regulatory jurisdictions, distribution investment costs and general function costs associated with serving customers in a specific jurisdiction should be assigned directly to that jurisdiction. Distribution expenses not directly assigned (e.g., the cost of operating and maintaining distribution substations) are generally allocated according to the percent of distribution investment costs assigned directly to each jurisdiction. Customer-related costs assigned to the general function category (e.g., customer accounting expenses) should be allocated on the basis of the number of customers served in each jurisdiction.

In the previous step, generation and transmission costs have been classified, resulting in the identification of demand- and energy-related generation costs and demand-related transmission costs for the total utility system. We recommend that similar methods be used to allocate demand- and energy-related generation costs and demand-related transmission costs to jurisdictions as well as to customer groups within each jurisdiction. Therefore, we include our recommended method for allocating these jurisdictional costs in the next section, which addresses the allocation of costs to customer groups.

ALLOCATE COSTS TO CUSTOMER GROUPS

Our recommended method for the last step in a cost-of-service study consists of 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.

Each substep is described below.

Identify Customer Groups

To identify customer groups, we recommend that the Oklahoma utilities use existing rate schedules if such rate schedules define homogeneous customer groups. However, unless a utility has sufficient load research data to identify kW demands, kWh usage patterns, load factors, and coincidence factors of different customers within a group (e.g., residential customers with electric water heating), the degree to which existing rate schedules define homogeneous customer groups cannot be determined. Thus, adequate load research data are needed to define customer groups, as well as to develop cost allocation factors.[2]

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2. If multiple schedules (e.g., multiple lighting service schedules) exist for similar types of service, the schedules may be combined to facilitate preparation of the cost-of-service study.

Allocate Demand-Related Generation and Transmission Costs

The three principal methods of allocating demand-related generation and transmission costs are: coincident peak (CP) responsibility, noncoincident peak (NCP) responsibility, and average and excess (A&E) demand.[3] This range of methods introduces an unavoidable element of subjectivity into the results of a cost-of-service study, and as such, selecting a method to allocate demand-related generation and transmission costs is a key issue that OCC must resolve. We describe each method below and recommend the most suitable method in terms of meeting PURPA's stated objectives.

Under the CP responsibility method, demand-related costs are allocated to each customer group in proportion to the group's CP demand, i.e., the group's demand at the time of the system peak. This method is appropriate when system peak demands are assumed to be the primary determinant of a system's required generation and transmission capacity, and, therefore, of demand-related costs.

However, there are certain conditions under which the use of a single system CP may be unsatisfactory for allocating demand-related costs. Specifically, when a utility has successively larger seasonal peaks, anticipates that peaks will change from one season to another, or has multiple peaks of approximately the same magnitude, the capacity responsibilities resulting from use of the single highest system peak may not accurately reflect the capacity responsibilities during the other significant system peaks. Furthermore, under the conditions listed above, if a single peak were used, the capacity responsibilities measured in one year could differ significantly from those measured in subsequent years, such that retail rates for different customer groups based on these measurements could radically shift

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3. There are many variations of these three methods. For example, the Electric Power Research Institute identified 29 methods of allocating demand-related costs in <u>Rate Design and Load Control: Issues and Directions</u>, prepared for the Electric Utility Rate Design Study, November 1977, p. 26.

from year to year. In such cases, we recommend the use of a multiple CP responsibility method, in which the average of several of the highest system peaks is used to calculate capacity responsibilities.

When the NCP responsibility method is used, demand-related costs are divided among customer groups in proportion to each group's NCP demand; i.e., the group's maximum peak demand regardless of the time of occurrence. Allocation of costs on the basis of each group's peak demand assumes that, if each customer group were served independently, facilities would be needed to meet its peak demand. However, because all of a utility's customers do not peak at the same time, use of the NCP responsibility method to allocate demand-related generation and transmission costs penalizes those customers whose peaks occur during the system's off-peak hours. Moreover, the NCP method distributes system-diversity benefits among all customer groups independently of the degree of coincidence between each group's maximum demand (NCP) and the system's peak demand.[4] As a result, the NCP method fails to recognize that customer groups whose peak demands coincide with the system's peak (i.e., customers with high-load factors) contribute minimally to system diversity.

The A&E method allocates demand-related costs on the basis of the sum of a group's average demand and the proportion of the system's excess demand attributable to that group. Excess demand is defined as the difference between an NCP and average demand.

The mathematical expression for a customer group's A&E demand is:

$$(A\&E)_i = \bar{D}_i + (CP_s - \bar{D}_s)\ \frac{NCP_i - \bar{D}_i}{NCP_s - \bar{D}_s}$$

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4. System-diversity benefits occur when the individual customer groups make their maximum demands on the system at different times, enabling the system to meet the coincident maximum demands with a lower level of capacity than needed to meet the sum of the individual group maximum demands.

where:

$(A\&E)_i$ = average and excess demand of the i^{th} customer group

$\overline{D}_i$ = average demand of customer group i, or the group's annual kWh usage divided by 8,760 hours

CP_s = coincident peak of the utility system

$\overline{D}_s$ = average demand of the utility system, or $\sum_i \overline{D}_i$

NCP_i = noncoincident demand of i^{th} customer group

NPC_s = noncoincident demand of the utility system, or $\sum_i NPC_i$.

The A&E demand allocation factor for each customer group is:

$$F_i = \frac{(A\&E)_i}{(A\&E)_s}$$

where:

F_i = A&E allocation factor for the i^{th} customer group

$(A\&E)_s$ = average and excess demand for the utility system, or $\sum_i (A\&E)_i$.

It should be noted that the A&E method recognizes more factors than either the CP or NCP method (e.g., NCPs and average demands of customer groups and the average demand, CP, and NCP of the utility system). However, it is unclear whether recognition of these factors is meaningful in terms of making the A&E method superior to either of the other allocation methods. Moreover, if both the group and system maximum demands included in the A&E formula are group and system CPs, the A&E method will become the CP method. Similarly, if the system NCP is used instead of the system CP, the A&E method will become the NCP method.

Similar to the CP method, the A&E method results in customer groups with high load factors receiving fewer system-diversity benefits than customer groups with low load factors. In fact, a customer group with a 100-percent load factor would receive no benefits because the group's maximum demand would coincide with the system peak demand. In effect, then, the A&E method recognizes that the probability of a customer group's maximum demand coinciding with the system peak increases as the group's load factor increases.

Of the three basic methods for allocating demand-related generation and transmission costs, we recommend the use of the CP responsibility method. This method allows for greater recognition of each jurisdiction's or retail customer group's responsibility for the utility's costs of building and maintaining the bulk power supply system.

Moreover, as discussed earlier, Section 115(a) of PURPA requires that OCC prescribe a cost-of-service methodology that permits the identification of the time-related cost differences of providing electric service. The CP method reflects these time-related cost differences more accurately than either the NCP or A&E method. For example, a utility that builds generation and transmission capacity to meet high summer peak demands should allocate the demand-related portion of these bulk power supply costs on the basis of the jurisdiction's or customer group's contribution to the growth of the summer peak. Use of the CP method to allocate demand-related generation and transmission costs will achieve this; use of either the NCP or A&E method will not fully recognize each jurisdiction's or group's contribution to the system peak.

To ensure that proper data are available to use the CP method, OCC should require the Oklahoma utilities to develop data on group and system maximum demands at the time of system peak. We recommend that these data, as well as noncoincident demand data used to allocate distribution costs, be obtained through load research studies using statistical sampling techniques, to minimize the number of locations to be monitored, and hence, the time and cost requirements of data collection.

Allocate Demand-Related Distribution Costs

Because the distribution system is built and maintained to meet maximum customer demands whenever they occur, it is appropriate to allocate demand-related distribution costs based on maximum group or customer demands (i.e., NCPs). Therefore, we recommend that the utilities use the NCP responsibility method to allocate demand-related distribution costs to retail customer groups. The noncoincident demands used should be estimated at the distribution level at which a customer group receives service (e.g., primary and secondary distribution voltage levels), or, in certain cases, at the transmission level. All customer demands should be adjusted for demand losses.

For example, to allocate demand-related costs of:

- Distribution substations, use group NCPs at the transmission level
- Primary distribution overhead lines, use group NCPs at the primary distribution level
- Secondary distribution overhead lines, use nondiversified, intragroup NCPs (i.e., the sum of the individual customer maximum demands regardless of the time of occurrence) at the secondary distribution level
- Distribution line transformers, use either group NCPs or the average of group NCPs and nondiversified, intragroup NCPs at the secondary distribution level.

Allocate Energy-Related Costs

When assigning costs to jurisdictions, energy-related costs should be allocated on the basis of the energy consumed in each jurisdiction, adjusted for line losses. For example, the ratio of residential kWh consumption (adjusted for line losses) to total kWh generated could be used to allocate energy-related costs to the residential customer group. This procedure requires readily available and reliable data and involves little subjectivity.

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, 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.

2 DECLINING BLOCK AND SEASONAL RATE STANDARDS

Two of the PURPA ratemaking standards that OCC must formally consider by 1981 concern the use of declining block and seasonal rates. Unless OCC determines that either or both of these standards are inappropriate in terms of PURPA's stated goals of conservation, efficiency, and equity or conflict with state laws, the commission must require the four Oklahoma utilities under its jurisdiction to meet these standards.

If OCC adopts the declining block rate standard, it must, as specified in Section 111(d.2) of PURPA, ensure that the energy-related cost component of a retail rate charged to any customer group does not decrease as the group's kWh consumption increases. A utility may only implement declining block rates when it can demonstrate that, for a particular customer group, the energy-related cost component decreases relative to increases in the group's kWh consumption during a particular period.

Two characteristics of declining block rates that are not specifically described in Section 111(d.2) of PURPA should be noted. First, in a declining block rate, the charge per kWh of consumption decreases as the customer's, not the group's, consumption increases. Second, a declining block rate is one in which either the stated demand or energy charge in the rate schedule decreases as the level of kW demand or kWh consumption increases.

PURPA's seasonal rate standard, as specified in Section 111(d.4), states that the retail rates charged to each customer group must reflect the costs of providing service to each group during different seasons of the year to the extent that the utility's costs vary seasonally.

In simple terms, these standards mean that a utility's rate for each customer group should include seasonal rate differentials without declining block rates, unless the results of a utility's cost-of-service study and additional analyses of a utility's operating costs indicate that energy-related costs decrease as consumption increases and do not vary by season. Thus, in considering these two standards, OCC should require each of the electric utilities covered by PURPA to provide an updated accounting cost-of-service study, hourly system production costs during the selected test year, and seasonal load forecasts by customer group, if possible. Although more detailed analyses and data (e.g., marginal cost studies, system dispatch analyses) could be used to assess whether or not declining block and seasonal rates are cost-justified, such analyses and data are not required for OCC to meet its obligations to consider the two ratemaking standards.

As discussed in the previous chapter, because rates based on cost-of-service promote PURPA's three goals, both the declining block and seasonal rate standards cannot be considered until OCC implements the cost-of-service standard. However, in considering the two rate standards, OCC should recognize that two principal objectives of rate design (i.e., rates that reflect cost-of-service and rates that recover costs from all customers in an efficient and equitable manner) may sometimes conflict. For example, as we describe later, for nonhomogeneous customer groups, declining block rates may be necessary to recover costs from a customer group in an efficient and equitable manner even though such rates may not be cost-justified.

To assist OCC in considering these two ratemaking standards, we reviewed the arguments typically used to justify declining block rates and delineated the steps necessary to determine the cost-justification for seasonal rates.

The four major arguments used to justify declining block rates are:

1. Utility economies of scale
2. Decreasing short-run average costs
3. Lower average total cost per kWh to serve higher load factor customers
4. Nonhomogeneity of certain customer groups.

Our review of these arguments indicates that, with the exception of the use of declining block rates to recover costs in an equitable manner from nonhomogeneous customer groups, such rates are not justified.

Although TOD rates are the preferred time-of-use rate form in terms of most accurately reflecting time-related cost differentials, seasonal rates should be used where TOD rates are not cost-justified because of excessive metering costs. If cost-justified, seasonal rates will promote PURPA's objectives.

In the remainder of this chapter, we describe the major ratemaking issues that OCC should address in considering the declining block and seasonal rate standards. These issues focus on whether or not such rates reflect cost of service and thereby provide proper price signals to customers. In Appendix B, we conduct a case-study analysis of the retail rates filed by OG&E in Cause No. 26495 and show how one Oklahoma utility addressed these ratemaking issues.

A. DECLINING BLOCK RATES

Declining block rates have been used in the utility industry for many years. Essentially, a declining block rate is one in which the stated demand or energy charge in a rate schedule decreases as the level of kW demand or kWh consumption increases.

We do not recommend the use of declining block rates because such rate forms cannot be justified on the basis of utility economies of scale, decreasing short-run average costs, or the relationship between the customer's load factor and the average total cost per kWh to serve the customer. However, we recognize that declining block rates may be required to recover the short-run costs of serving a nonhomogeneous customer group in an equitable manner. In this instance, PURPA's goals of developing rates based on cost of service and developing equitable rates are conflicting.

If declining block rates are used, OCC should require the utilities to provide evidence that such rates either accurately reflect cost of service or are required to recover short-run total costs from customer groups in an equitable manner. To gather such evidence, the utilities will need to perform cost-of-service studies using reasonable allocation methods. In addition, they will need to develop adequate load research, accounting, and forecast data that can be used in identifying nonhomogeneous customer groups and in performing the cost-of-service studies.

In the remainder of this section, we assess the major arguments used to justify declining block rates.

UTILITY ECONOMIES OF SCALE

Proponents of declining block rates have argued that the electric utility industry's decreasing long-run average costs justified the use of such rates. Until around 1970, the industry experienced decreasing long-run average costs, or economies of scale, which resulted primarily from technological improvements in generating equipment (e.g., improved heat rates for coal-fired generating units). In other words, average production costs were reduced as new generating plants were built and placed in operation to meet growth in electricity demands.[1]

However, current and expected operating conditions no longer support this argument. Since 1970, few technological advances in steam or nuclear generator productivity have occurred, and rapid real cost increases in construction and fuel costs have occurred. Because productivity increases have not offset real cost increases in recent years and are not expected to offset real cost increases in the future, the utility industry is no longer experiencing decreasing long-run average costs. Thus, declining

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1. Long-run average costs are the expected average costs that a utility will incur as it increases its production capability by building new generating, transmission, and distribution facilities over a designated planning period.

block rates can no longer be justified on the basis of decreasing long-run average costs.

UTILITY SHORT-RUN AVERAGE COSTS

Another argument used to justify declining block rates is that the average kWh charge necessary to recover short-run fixed demand- and customer-related costs decreases as kWh consumption increases.[2] Thus, rates designed to reflect short-run decreasing average costs should decrease as kWh consumption increases.

This argument is based on the assumption that increases in variable energy-related costs are offset by continuously decreasing average fixed costs. However, this assumption does not always hold true. If energy-related costs increase as kWh production exceeds a given level (i.e., as less efficient, higher cost generating units are used to meet increased customer demands), total short-run average costs may also begin to increase as kWh consumption increases. Because most utilities have to use less efficient units to meet increased demand in the short term, they may only experience short-run decreasing average costs over a portion of their total kWh production.

In general, a utility will not experience short-run decreasing average costs throughout all of its kWh production unless it can meet all of its energy and power demands using (1) baseload thermal or nuclear generating capacity or (2) a combination of baseload and hydroelectric or pumped storage capacity.

Even if short-run costs decrease, long-run average costs will continue to increase, as described in the previous section. OCC has a legal obligation to set rates that

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2. Short-run average costs are the fixed and variable costs incurred during the operation of a fixed capital plant. Short-run demand- and customer-related costs are fixed because they represent existing plant investments. Short-run energy-related costs are variable because they depend on the number of kWh used by customers and the types of capacity used to produce the kWh.

will enable a utility to recover its total short-run operating costs, including a fair return on its historical capital investment. However, if rates reflect decreasing short-run average costs (i.e., declining block rates) at the same time that a utility faces increasing long-run average costs, the customer price signals from such rates will be distorted. Therefore, regardless of its short-run operating conditions, a utility cannot justify the use of declining block rates on the basis of decreasing costs.

CUSTOMER LOAD FACTORS AND AVERAGE COSTS

A third argument used by proponents to justify declining block rates is based on the hypothesis that the higher a customer's load factor, the lower the average total cost per kWh to serve that customer. If this hypothesis were true, declining block rates would be cost-justified. However, the argument only holds true if the following conditions exist:

1. Demand- and energy-related costs are recovered through a kWh charge
2. The utility's average demand- and energy-related costs are the same for all customers within a group regardless of individual kWh consumption levels
3. Increases in average demand-related costs as load factors increase are spread over enough kWh such that average total costs per kWh continuously decrease.

The third condition is based in part on the assumption that average energy-related costs are the same for all customers within a group. Because it is impossible to prove that (1) average energy-related costs are the same for all customers within a group), and (2) short-run average total costs continuously decrease even if average demand-related costs increase, it is impossible to prove this hypothesis. Consequently, declining block rates cannot be justified on the basis of this assumed relationship between customer load factors and average costs.

In the following paragraphs, we describe the analytical approach that is typically used by proponents to support this hypothesis and explain why this approach is deficient.

The analytical approach consists of three steps:

Step 1: Derive average demand-, energy-, and customer-related costs for each customer group from the results of an accounting cost-of-service study

Step 2: Estimate the total cost of serving two customers in a particular customer group who have identical kW demands but different load factors (i.e., the customers have different levels of kWh consumption per kW demand)

Step 3: Divide the total cost of serving each customer by the customer's kWh consumption to derive the average cost per kWh of serving the customer.

For example, assume the results of a cost-of-service study indicate that the residential customer group has average monthly demand-, energy-, and customer-related costs of service of \$3 per kW, \$0.02 per kWh, and \$6 per customer, respectively. Also, assume that within the group there are two residential customers (A and B) having identical kW demands but different load factors. Let each customer's average monthly demand be 5 kW, but assume that customers A and B have average monthly load factors of 0.8 and 0.2, respectively. The total monthly cost of serving customer A is \$79.40.[3] The average cost per kWh of serving customer A is \$0.0272.[4] For customer B, the total monthly cost is \$35.60, and the average cost per kWh is \$0.0488.[5] Thus, if a kWh charge were used to recover the average monthly costs of serving customers A and B, the charge would have to decrease as kWh consumption increased to recover the costs of serving customers A and B in an equitable manner.

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3. \$79.40/mo = \$6.00/mo + (5 kW/mo)(\$3/kW) + (\$0.02/kWh)(0.8)(5 kW)(730 hr/mo).

4. \$0.0272/kWh = \$79.40/mo ÷ 2,920 kWh/mo.

5. \$35.60/mo = \$6.00/mo + (5 kW/mo)(\$3/kW) + (\$0.02/kWh)(0.2)(5 kW)(730 hr/mo).
\$0.0488/kWh = \$35.60/mo ÷ 730 kWh/mo.

Although this approach is mathematically correct, it is deficient in three respects.

First, the approach assumes that the demand-related costs per kW of serving two customers with different load factors are the same. In fact, there is a direct relationship between load factor and cost per kW to serve a customer or customer group.[6] Specifically, the higher a customer's load factor, the higher the probability that the customer's peak demand coincides with system peak demand.[7] Thus, when two customers have identical energy consumption levels, the customer having the higher load factor is responsible for more demand-related costs of facilities built to meet system peak demands (e.g., generating units). If the total demand- and energy-related costs of serving each customer are divided by the customer's kW demand, the average cost per kW will be higher for the customer with the higher load factor.

Second, the approach ignores the fact that the average cost to the utility of serving two customers using the same number of kWh may differ. A kWh declining block rate will be unable to recover these different costs in an equitable manner. For example, if a kWh declining block rate were used to recover the cost of serving the residential customer group described above, it would be impossible to distinguish between customers who consume the same number of kWh but have different demands and load factors. Failure to make this distinction would result in an inequitable cost recovery from customers within the group. For example, assume customer C, like customer B above, consumes an average of 730 kWh per month. However, customer C has an average monthly demand of 1.25 kW and an average monthly load factor of 0.8. The total cost of serving customer C is $24.75 per

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6. C.W. Barry, <u>Operational Economics of Electrical Utilities</u>, Columbia University Press, New York, 1965, pp. 52-64.

7. The relationship is as follows: the higher a customer's load factor, the higher the probability that the customer's peak demand coincides with the group's maximum demand; the higher the group's load factor, the higher the probability that its maximum demand coincides with system peak demand; therefore, the higher the probability that the customer's peak demand coincides with system peak.

month, with an average cost per kWh of $0.0333.[8] It is not possible to set a kWh rate to recover an average cost of $0.0333 per kWh for customer C while recovering $0.0488 from customer B when both customers use an average of 730 kWh per month.

The third and most serious deficiency of this approach is the assumption that the utility's average energy-related costs are the same for all customers within a group regardless of individual kWh consumption levels. As we noted earlier, only if the utility can meet all of its energy requirements using baseload or hydroelectric capacity, is it reasonable to assume the same average energy-related costs for all customers within a group. Moreover, it is impossible to identify realistically the effects of minor increases in one customer's (or group's) kWh consumption on total system costs.

NONHOMOGENEOUS CUSTOMER GROUPS

When setting rates for nonhomogeneous customer groups, the use of declining block rates may be justified.[9] However, as explained in the following paragraphs, use of declining block rates in this situation involves a trade-off between rates based on cost of service and rates that treat customers equitably. Even when separate kW, kWh, and customer charges are included in a group's rate, it may be impossible to recover short-run total costs from a nonhomogeneous customer group in an equitable manner without including a declining block energy rate. For example, it may be necessary to recover a

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8. $24.35/mo = $6/mo + (1.15 kW/mo)($3/kW) + ($0.02/kWh)(0.8)(1.25 kW)(730 hr/mo).
$0.0333/kWh = $24.35/mo ÷ 730 kWh/mo.

9. For a case-study analysis of situations in which declining block rates may be justified by customer group nonhomogeneity, see RPA, Innovative Rates for Central Maine Power Company's General Service Customers, prepared for NRRI, July 16, 1979, pp. 1.22-1.24.

portion of the group's demand-related costs through a declining block energy charge assuming the following customer group characteristics:

- A rate is applicable to customers served at both primary and secondary voltage levels
- The demand- and energy-related costs of serving customers at the primary level differ from the costs of serving customers at the secondary level
- Customers at the primary level have significantly different average load factors, kW demands, and kWh usage from secondary customers.

Because of these customer group characteristics, the utility may find that flat demand and energy charges for the group create an unacceptable overcharging of some customers and undercharging of others.

The recent trends by utility commissions to reduce the number of retail rate schedules and to flatten rates within schedules may result in an inequitable recovery of costs within the rate schedule if nonhomogeneous customer groups are covered in the same rate schedule. If such situations arise, OCC should attempt to minimize deviations from demand- and energy-related costs derived from the utility's cost-of-service study. Moreover, OCC should assess the need for new customer group designations (e.g., service by voltage level).

B.
SEASONAL RATES

A seasonal electric rate is a time-of-use rate that relates the price of electricity to the seasonal costs of providing that electricity. Because utility generating costs are typically 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.

We recommend that OCC require the Oklahoma utilities to develop rates reflecting the different costs of providing service according to time of use. Although we prefer TOD rates because they are the most exact means of reflecting time-related cost differentials, we recognize that, in some cases, TOD rates cannot be implemented easily (i.e., customers do not already have metering capable of measuring usage by time of day and are unwilling to pay the additional costs of such metering). In such cases, seasonal rates are an acceptable alternative to TOD 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 PURPA's goals of conservation, efficiency, and equity. Conservation occurs because seasonal prices paid by consumers reflect the utility's cost of providing electric service more accurately than do non-time-differentiated rates, and, hence, provide proper price signals. Production efficiency is increased as demand and utilization of generation equipment become more balanced from a decrease in seasonal peak consumption and an increase in seasonal off-peak consumption. Equitable rates are promoted because customers are charged on the basis of the utility's costs of meeting their relative demands on the system by time of use.

Although seasonal electric rates can be beneficial in terms of increasing conservation and production efficiency and reducing future capacity requirements, the justification for such rates must occur on a utility-specific basis. Seasonal rates should only be instituted when:

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

2. A utility's installed capacity requirements are primarily determined by the system peak demand during a particular season

3. A utility expects its peak demand to continue to occur 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 seasonal rates, however, can be large or small; in some cases, such 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 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.

Assuming a utility can demonstrate that the benefits of introducing seasonal rates exceed the costs, such rates should be implemented regardless of whether or not they result in a large or small improvement in a utility's load factor. Only when rates are designed to reflect time-related cost differences can customers make reasonable and efficient decisions about how and when to consume electricity. Moreover, because customers make energy-related investment decisions, such as the installation of more efficient space-heating equipment, at least in part on the basis of relative electricity prices, it is important that any seasonal differential that is implemented accurately reflect a utility's relative cost differential of producing electricity during different seasons. These costs differentials should be derived from analyses of the cost impacts of seasonal variations on a utility's capacity expansion plans, operating costs, and ability to perform maintenance on its generating units. After the cost differences have been estimated, load and billing data should be used to develop the seasonal rate differential for each customer group or rate schedule.

APPENDIXES

Appendix A

OG&E COST-OF-SERVICE STUDY

In Chapter 1, we outlined the steps for conducting an electric utility cost-of-service study based on accounting costs and identified four major issues that the OCC should resolve in selecting a standard cost-of-service study methodology. These issues are:

1. Should future as well as historic test years be used for determining revenue requirements?

2. How should distribution system costs be classified into their demand- and customer-related components?

3. How should demand-related production, transmission, and distribution costs be allocated to jurisdictions and customer groups?

4. What load research data are necessary for accurately determining cost of service?

To demonstrate how one utility under OCC's jurisdiction has dealt with these issues, we evaluated the cost-of-service study submitted by OG&E in Cause No. 26495 as supporting evidence in the company's request for a general increase in its retail rates in Oklahoma. Because RPA is not a party-of-record in this case, our comments focus only on the key methodological issues in the performance of the cost-of-service study. As such, we do not address the appropriateness of the revenue requirements.

Before proceeding with our discussion of the four issues listed above, we briefly describe OG&E's cost-of-service study.

In conducting its cost-of-service study, OG&E generally followed the five steps described in Chapter 1 of this report.[1] Below, we describe OG&E's study according to each step:

1. Test period. OG&E's study was conducted using data from an historical test year ending December 31, 1978.

2. Assignment of cost by function. OG&E used the FERC uniform system of accounts to assign investment costs and operating and maintenance expenses to production, transmission, distribution, and general functions.

3. Classification of cost within functions. Except for costs and expenses directly assigned to customers or jurisdictions, OG&E disaggregated production, transmission, distribution, and general costs into their demand-, energy-, and customer-related components. Exhibits A.1 and A.2 show OG&E's classification of plant and operations and maintenance expenses, respectively.

As shown in the exhibits, all production plant costs were classified as demand-related. OG&E classified most production operating and maintenance expenses as 70-percent demand-related and 30-percent energy-related. Supervision and engineering expenses were allocated according to operations and maintenance labor; all rental costs were classified as demand-related; and purchased power expenses were classified as both energy- and demand-related, but not in the same proportion as other production costs. Except for accounts directly assignable to specific customers or groups, transmission plant and operating and maintenance expenses were classified as demand-related. Distribution plant and operating and maintenance expenses not directly assignable to customers were classified as demand- and/or customer-related.

4. Allocation of costs to jurisdictions. OG&E allocated its costs among the three jurisdictions it serves: Oklahoma, Arkansas, and FERC. Energy-related costs were allocated on the basis of kWh usage adjusted for

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1. OG&E's sequence of steps differs somewhat from RPA's recommended sequence. The cost classification used by OG&E is shown in Exhibits A.1 and A.2.

Exhibit A.1

OG&E Classification of Plant Accounts

FERC Account No.	Account Description	Cost Classification: Demand-Related	Energy-Related	Customer-Related
301-303	**Intangible Plant**	●	●	●
310-346	**Production Plant**	●		
350-359	**Transmission Plant***	●		
	Distribution Plant			
360	Land and land rights*	●		
361	Structures and improvements*	●		
362	Station equipment*	●		
364	Poles, towers, and fixtures	●		●
365	Overhead conductors and devices	●		●
366	Underground conduit	●		●
367	Underground conductors and devices	●		●
368	Line transformers	●		
369	Services			●
370	Meters			●
371	Installations on customers' premises**			
373	Street lighting and signal systems**			
389-398	**General Plant**	●	●	●

SOURCE: OG&E Rate Application, OCC Cause No. 26495, Section K, Schedule 8.

*Where customers or jurisdictions have exclusive use of facilities in this account, the costs are directly assigned to those customers or jurisdictions.

**The costs of these facilities are directly assigned to the customer group or jurisdiction having exclusive use of the facilities.

Exhibit A.2

OG&E Classification of Operation and Maintenance Expenses

FERC Account No.	Account Description	Cost Classification: Demand-Related	Energy-Related	Customer-Related
	Steam Power Production			
	Operation			
500	Supervision and engineering	●		
501	Fuel		●	
502	Steam	●	●	
505	Electric	●	●	
506	Miscellaneous steam power	●	●	
507	Rents	●		
	Maintenance			
510	Supervision and engineering			
511	Structures	●	●	
512	Boiler plant	●	●	
513	Electric plant	●	●	
514	Miscellaneous steam plant	●	●	
	Other Power Production			
	Operation			
546	Supervision and engineering	●		
547	Fuel		●	
548	Generation	●	●	
549	Miscellaneous other power	●	●	
	Maintenance			
551	Supervision and engineering	●		
552	Structures	●	●	
553	Generating and electric equipment	●	●	
554	Miscellaneous other power	●	●	
	Other Power Supply Expenses			
555	Purchased power	●	●	
556	System control and load dispatching	●		
557	Variable production O&M expense adjustment		●	
	Transmission			
	Operation			
560	Supervision and engineering			
561	Load dispatching	●		
562	Station*	●		
563	Overhead lines	●		
564	Underground lines	●		
566	Miscellaneous transmission	●		
567	Rents	●		

Exhibit A.2 (continued)

OG&E Classification of Operation and Maintenance Expenses

FERC Account No.	Account Description	Cost Classification: Demand-Related	Energy-Related	Customer-Related
	Maintenance			
568	Supervision and engineering	●		
569	Structures*	●		
570	Station equipment*	●		
571	Overhead lines	●		
573	Miscellaneous transmission plant*	●		
	Distribution			
	Operation			
580	Supervision and engineering	●		
582	Station*	●		
583	Overhead lines	●		●
584	Underground lines	●		●
585	Street lighting and signal systems			
586	Meters			●
587	Customer installations			●
588	Miscellaneous distribution	●		●
589	Rents	●		●
	Maintenance			
590	Supervision and engineering	●		
591	Structures*	●		
592	Station equipment*	●		
593	Overhead lines*	●		●
594	Underground lines	●		●
595	Line transformers	●		
596	Street lighting and signal systems**			
597	Meters			●
598	Miscellaneous distribution plant	●		●
	Other Operating Accounts			
905	Customer accounts			●
910	Customer service and information			●
916	Sales			●
924, 926, 934	Administrative and general	●	●	●

SOURCE OG&E Rate Application, OCC Cause No. 26495, Section K, Schedule 10.

*Where customers or jurisdictions have exclusive use of facilities in this account, the costs are directly assigned to those customers or jurisdictions.

**The costs of these facilities are directly assigned to the customer group or jurisdiction having exclusive use of the facilities.

losses. Demand-related production and transmission costs were allocated using a modified CP responsibility method.

5. <u>Allocation of costs to customer groups</u>. OG&E allocated energy-related costs to customer groups (defined by its rate schedule) within Oklahoma on the basis of kWh usage adjusted for losses. Customer-related costs were allocated to customer groups on the basis of relative costs per type of customer and the number of customers within each group. Although OG&E used the CP method for the jurisdictional allocation, the company allocated demand-related production and transmission costs to customer groups within the Oklahoma jurisdiction using the A&E method. Finally, OG&E allocated demand-related distribution costs to customer groups in Oklahoma on the basis of modified A&E demand allocation factors. A summary of OG&E's allocation factors is shown in Exhibit A.3.

In general, OG&E's cost-of-service study represents a reasonable attempt to identify each customer group's cost responsibility. We disagree with two methods used by OG&E in its study: the methods used to classify customer-related distribution costs and to allocate demand-related production and transmission costs among jurisdictions and among customer groups within the Oklahoma retail jurisdiction. However, the major deficiency of OG&E's study is the lack of adequate load research data to identify customer groups and allocate costs to each group. Although this deficiency may not adversely affect OCC's ability to set reasonable revenue requirements for each customer group served by OG&E, it will prevent OG&E and OCC from complying with PURPA's requirements in particular, the Section 111 ratemaking standards and the Section 133 cost-of-service data requirements). Thus, both OCC and OG&E should work closely to expedite planned improvements in OG&E's load research program.

In the remainder of this appendix, we discuss the methodological issues highlighted in Chapter 1 relative to OG&E's cost-of-service study.

Exhibit A.3

OG&E A&E Allocation Factors for Customer Groups Within Oklahoma Jurisdiction

Customer Group	Allocation Factors (%)		
	Production	Transmission	Distribution
Residential	44.794	44.794	49.396
Commercial	22.746	22.746	24.881
Power & Light	12.157	12.157	13.189
Large Power & Light	18.511	18.511	10.777
Outdoor Lighting	00.446	00.446	00.492
Pumping	01.346	01.346	01.256
Total	**100.000**	**100.000**	**100.000**

USE OF FUTURE TEST YEAR

In accordance with OCC's minimum standard filing requirements, OG&E used an historical test year in its study. In other words, allocation factors and estimated rates of return were based on investment, expenses, revenue, kWh sale, kW demand, and customer data for 1978. However, during an interview with OG&E officials, they indicated that, because earnings have decreased from inflation and increasing costs during the past several years, OG&E would prefer to use a future as well as historical test year in its cost-of-service study to determine revenue requirements.

We recommend that OCC consider amending Section 2.30 of its minimum standard filing requirements to require the use of future as well as historical test periods for electric utility cost-of-service studies. OCC may continue to establish revenue requirements and set rates using historical test year data; however, OCC will also be able to evaluate the effects of its decisions using future test year data. We believe that such an approach would be beneficial to both consumers and the utility's stockholders.

CLASSIFICATION OF DISTRIBUTION COSTS

OG&E classified those distribution costs that could not be directly assigned (e.g., poles, towers, and fixtures; overhead conductors and devices; underground conductors and devices) into their demand- and customer-related components. OG&E representatives explained that the customer-related components of these distribution system accounts were based on plant investment per average-usage (kWh) customer in each customer group.[2]

OG&E estimated plant investment costs using the results of a detailed survey of the distribution plant. These investment costs were then regressed on kWh usage to

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

derive an estimated investment cost per average-usage customer (i.e., the customer-related costs). The remaining costs were classified as demand-related costs. This method is simliar to the zero-intercept method described in Chapter 1, except that average kWh, rather than zero kW load, is used.

A potential problem resulting from the use of OG&E's methodology is that, to the extent that investments associated with capacity contribute to the investment per average-usage customer, the customer-related cost component may be overstated. If rate schedules were developed based on these allocated costs, the demand-related costs used to derive the demand charges would be too low (and customer-related costs, too high), giving improper price signals to consumers with regard to the true cost of meeting customers' maximum kW demands.

The selection of an appropriate methodology for classifying distribution costs is critical to satisfying Section 115(a) of PURPA, which requires the use of a methodology that permits identification of demand-, energy-, and customer-related components. Both the minimum-size and zero-intercept methods attempt to identify the customer-related component of distribution facility costs. However, we recommend use of the zero-intercept method because, as explained in Chapter 1, this method establishes the statistical relationships between the customer- and demand-related components of distribution costs.

ALLOCATION OF DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS

OG&E used two different methods to allocate demand-related production and transmission costs: a modified CP responsibility method for its jurisdictional allocation and the A&E method for its retail allocation within Oklahoma. In the following paragraphs, we comment on each of these methodologies and the problems associated with using two different allocation methods in the same cost-of-service study.

Although OG&E has stated a preference for the A&E method, the company used a modified CP responsibility method to allocate demand-related production and transmission costs among the Oklahoma, Arkansas, and FERC jurisdictions. The CP method was originally used to allocate costs to the Arkansas jurisdiction as required by the Arkansas Public Service Commission. In addition, FERC generally requires the use of the CP method. OG&E representatives stated that the company extended the use of the CP method to all of its jurisdictional cost allocations because it feared that, by using a different allocation method, rate base and expenses might be underallocated to the Oklahoma retail jurisdiction. (Using a different method could also result in an overallocation of rate base and expenses to the Oklahoma retail jurisdiction.)

OG&E derived its allocation factors by averaging peak loads on 7 days (6 in July 1978, and 1 in August 1978). Although using the average of more than one system CP may give more stable and equitable results than simply selecting one daily CP, OG&E's approach for selecting the 7 days from which to derive an average appears to be somewhat arbitrary. During OG&E's general rate case, company representatives testified that three of the days selected represented the system's three highest peaks; two of the days selected represented the Arkansas jurisdiction's and the large power and light customer group's peaks. Although it is reasonable to select the system's highest peak days when using a multiple CP method, it is inconsistent to also use specific customer or jurisdictional (e.g., Arkansas) peaks as a criterion for selection. If OG&E believed that seven peaks should have been used, the company should have used the seven highest system peaks to derive an average CP.

OG&E used its preferred method, the A&E method, to allocate production and transmission demand-related costs to customer groups within the Oklahoma retail jurisdiction. Although OG&E prefers this method because of its direct recognition of customer group load factors, we do not recommend the A&E method because it fails to accurately recognize a particular group's contribution to system peak.

Moreover, the A&E method, as applied by OG&E, resulted in excess demands being assigned to a customer group (i.e., the outdoor lighting class) that did not contribute to the system's excess demand.[3] Recognizing this inequity, OG&E discounted the computed A&E demand of this customer group by the excess amount. OG&E then used the group's average demand in determining the sum of all customer groups' A&E demand to derive the A&E demand allocation factors. We do not dispute the numerical accuracy of this adjustment; rather, we believe that an allocation method, such as the A&E method, that results in excess demands being allocated to a customer group whose maximum demand occurs during off-peak hours, should not be used because it produces unreasonable and inaccurate results in certain situations. Although the magnitude of the adjustment in this case is insignificant, a large off-peak load requiring a similar judgmental adjustment could lead to more questionable results.

Regardless of the method selected, two different allocation methods should not be used in the same cost-of-service study because their underlying assumptions about the electric plant differ. Specifically, use of the CP method is based on the assumption that the company's production and transmission system was designed to meet peak system capacity requirements. In contrast, the A&E method is based on the assumption that, although a plant may be built to meet peak demands, baseload plant costs should be borne by all customers, thereby justifying the use of average demands. We recommend that the OCC, in prescribing procedures for performing cost-of-service studies, require the consistent use of one methodology, preferably the CP method, for cost allocation to both jurisdictions and customer groups.

ADEQUACY OF LOAD DATA

Regardless of the methods used in determining cost of service, reliable data must be developed from a utility's accounting, customer billing, property, and engineering records; load research studies; and system forecasts of load and sales growth. With the exception of load data, these data are readily obtainable.

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3. OG&E Cost of Service Study, Cause No. 26495, Section K, Schedule 6, p.2.

The specific load data required depend on the allocation method used. Data on group maximum demands at the time of system peak are required if the CP responsibility method is used, and data on group maximum demands regardless of their times of occurrence are required if the NCP method is used. For the A&E method, demand data required will depend on the variation used. For example, if system excess demand is defined to be the average of several system peaks minus the system average demand, system peak data will be required. Because the reliability of demand allocation factors is highly dependent on the accuracy of the demand data, we recommend that these data be obtained through load research studies using statistical sampling techniques to minimize the number of locations to be monitored, and, hence, the cost and time requirements of data collection.

Our review of OG&E's cost-of-service study and supporting testimony and our discussions with company representatives indicate that the company did not have sufficiently detailed load data to accurately determine all of the group CP demands and load and coincidence factors. Given the lack of adequate load research data, the methods used by OG&E appear to be reasonable. However, as we pointed out earlier, OG&E's existing load research data and program are inadequate to meet the company's and OCC's obligations under PURPA.

Load research data on the residential customer group are particularly deficient. In fact, OG&E representatives indicated that, because of the lack of adequate demand data for the residential and commercial groups, the company had to derive demand figures using judgment and the results of previous studies. For example, for the residential class, an hours-use load factor was estimated on the basis of judgement. This factor was then used, in conjunction with data from a sample of distribution circuits serving 700 residential customers and data from a previous transformer load study and a recent water heater study, to estimate the group demand at the time of system peak.

Because all of OG&E's large power and light customers were monitored with meters capable of measuring peak demands and their time of occurrence, data on this class were sufficient. Ten percent of the power and light customer group was similarly monitored; however, we do not know if this sample is representative of the entire class and, therefore, cannot determine the reliability of the demand data for this class.

Because the deficiencies in demand data identified in OG&E's cost-of-service study may be common to the other three Oklahoma utilities, OCC should review each utility's existing and proposed load research programs to determine their adequacy in providing data for determining cost of service and allowing subsequent evaluation of the other PURPA ratemaking standards. If deficiencies in the programs are found, the OCC should require the utilities to expand these programs.[4]

In specifying the detailed load data requirements, OCC can use the FERC regulations that implement PURPA (Section 133) as a guide. These regulations will require electric utilities to collect information necessary for determining the costs of providing electric service, to file such information with FERC and OCC, and to make this information publicly available. In June 1979, FERC issued regulations detailing the specific information requirements, which fall into the following four broad categories (as listed in Section 133 of PURPA):

1. Cost of serving each customer class
2. Representative daily kW demand curves for all customer groups, both separately and combined
3. Annual capital, operating, and maintenance costs
4. Costs of purchased power.[5]

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4. OG&E has already planned to upgrade its load research program.

5. Rules and Regulations, Federal Register, June 13, 1979, p. 33847.

Appendix B

OG&E DECLINING BLOCK AND SEASONAL RATES

In this appendix, we evaluated the declining block and seasonal rate features of the major rate schedules proposed by OG&E in Cause No. 26495 to determine if the proposed rates reflect cost of service and thereby promote the achievement of PURPA's objectives. In performing this evaluation, we reviewed testimony filed in Cause No. 26495 by a consultant to OCC and OG&E officials and interviewed OG&E representatives to discuss specific questions regarding the proposed retail rates.

On the basis of our evaluation, we determined that (1) OG&E's declining block rates are not cost-justified, and, therefore, do not promote PURPA's objectives, and (2) the company's seasonal rate differentials are probably justified, although we were unable to determine the correct magnitude of the seasonal rate differentials from the testimony, cost-of-service study, and related work papers prepared by OG&E for its rate case.

In the remainder of this appendix, we present the details of our evaluation.

The major rate schedules proposed by OG&E included two schedules for residential customers (Rates RES and RWH), one schedule for commercial customers (Rate C-1), and two schedules for the power and light customer group (Rates PL-1 and LPL-1).

As shown in Exhibit B.1, both residential rates include a minimum monthly bill provision of $1.59, five energy usage blocks with declining rates for higher kWh usage (except for the fourth block of Rate RWH), and seasonal differentials for the energy charges in each block. The proposed commercial schedule shown in Exhibit B.2 also includes a declining block kWh rate with a minimum monthly bill provision of $5.05 and a seasonal rate

Exhibit B.1

OG&E Proposed Residential Rate Schedules

Rate Schedule	Monthly Energy Usage (kWh)	Peak Season Charge*	Off-Peak Season Charge**
Rate RES	0-16	$1.59	$1.59
	17-40	7.448¢/kWh	6.927¢/kWh
	41-120	6.206¢/kWh	5.768¢/kWh
	121-600	4.790¢/kWh	4.108¢/kWh
	>600	4.068¢/kWh	2.471¢/kWh
Rate RWH	0-16	$1.59	$1.59
	17-40	7.448¢/kWh	6.927¢/kWh
	41-120	6.206¢/kWh	5.768¢/kWh
	121-600	3.483¢/kWh	2.889¢/kWh
	>600	4.068¢/kWh	2.471¢/kWh

*Peak season includes months of June through October.
**Off-peak season includes months of November through May.

Exhibit B.3

OG&E Proposed Power and Light Rate Schedules

Rate Schedule	Monthly Billing Demand* (kW)	Peak Season Demand Charge** ($/kW)	Off-Peak Season Demand Charge† ($/kW)	Monthly Energy Usage (kWh)	Monthly Energy Charge (¢/kWh)
Rate PL-1	>0	2.76	1.94	0-15,000	3.810
				15,001-32,500	3.006
				32,501-70,000	2.465
				>70,000	2.144
Rate LPL-1	0-400	2.81	2.81	0-100,000	2.542
	>400	2.06	2.06	100,001-2,000,000	2.033
				> 2,000,000	1.947

*The monthly billing demand for a customer on Rate PL-1 is equal to the greatest of (1) the customer's maximum kW demand during any 15-minute period of the billing period, (2) 65 percent of a customer's maximum kW demand during the peak season for the most recent 12-month period, or (3) 10 kW. The monthly billing demand for a customer on Rate LPL-1 is equal to the greatest of (1) the customer's maximum kW demand during any 15-minute period of the billing month, (2) 65 percent of the customer's maximum kW demand during the most recent 12-month period, or (3) 400 kW.

**Peak season includes months of June through October.

†Off-peak season includes months of November through May.

$5.12 for residential customers and $19.38 for commercial customers.[3] However, because the proposed residential and commercial rates include minimum monthly bill provisions, instead of separate monthly customer charges, about 70 percent of the average customer-related costs for both customer groups are recovered through the kWh energy charges of the proposed rates. By setting separate monthly customer charges approximately equal to the average monthly customer costs for each group, OG&E could significantly reduce the declining block characteristic of Rates RES, RWH, and C-1. Furthermore, OCC should consider an alternative design for Rates RES and RWH, in which the rates would have separate customer charges, a flat kWh charge in the peak season, and a two block declining kWh energy charge in the winter season.

Finally, OG&E should demonstrate that the declining block kW and kWh features of Rate LPL-1 are justified on the basis of the nonhomogeneity of the large power and light customer group. Unless OG&E can demonstrate that these features are necessary to recover costs of service in an equitable manner from a nonhomogeneous customer group, OCC should require OG&E to flatten the kW and kWh charges in the rate. If this customer group is nonhomogeneous, OCC should consider whether two rate schedules for this customer group should be developed to recover costs of service equitably and promote efficient energy consumption.

OG&E included seasonal rate differentials in the kWh charges of Rates RES, RWH, and C-1, and in the kW charges of Rate PL-1. Rate LPL-1 does not include seasonally differentiated charges. During our interview with OG&E officials, we were informed that the seasonal rate differentials included in the company's proposed retail rates were based on an analysis of seasonal loads and energy usage performed by a consultant to OG&E in 1976. This analysis was neither updated nor modified in the 1978-test-year cost-of-service study on which the company based its proposed rates. However, this is a minor deficiency that can be easily remedied by OG&E. The results of an updated analysis could be used to set

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3. Testimony of Howard E. Lubow, Cause No. 26495, June 1979, Exhibit HEL-2, Schedule 2.

appropriate seasonal rate differentials for the various customer groups.

OG&E's use of seasonal rate differentials is cost-justified and has resulted in improved annual load factors. For example, during recent years in which OG&E has used seasonal rate differentials, the company's winter peak growth has been greater than its summer peak growth (see Exhibit B.4). Although not all of this growth differential can be attributed to the effects of seasonal rates, it is reasonable to assume that without these rate differentials, the difference in the company's summer and winter peaks would have been larger, resulting in a lower annual load factor and less efficient use of the company's generating facilities.

We do suggest, however, that OG&E reexamine its decision to omit seasonal rate differentials in Rate LPL-1, under which large commercial and industrial customers are billed. OG&E justified this exclusion on the basis that, because customers served under the rate have relatively constant monthly kW demands and load factors, the monthly bills for these customers should be relatively equal (that is, recovery of the total cost of serving these customers should be spread out evenly through the year). Thus, seasonal rates, which would recover more revenue from these customers durng the summer months, were excluded from Rate LPL-1. Excluding seasonal rate differentials distorts the price signals received by large power and light customers, thereby promoting inefficient energy consumption and investment decisions by this group. In other words, the proposed Rate LPL-1 fails to promote PURPA's objectives.

Finally, OCC should require OG&E (as well as the other three Oklahoma utilities covered by PURPA) to provide average demand-, energy, and customer-related costs by season for each customer group. Such information could be derived from the utilities' cost-of-service studies. OCC could then identify specific cost components and the manner in which the utilities recover these components in their rates.

Exhibit B.4

OG&E Seasonal Peak Loads

Season		Peak (MW)		Annual Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter
1972	1971-1972	2,645	1,575		
1973	1972-1973	2,775	1,810	4.91	14.92
1974	1973-1974	3,140	1,950	13.13	7.73
1975	1974-1975	3,185	2,025	1.43	3.85
1976	1975-1976	3,335	2,370	4.71	17.04
1977	1976-1977	3,650	2,470	9.45	4.22
1978	1977-1978	3,805	2,580	4.25	4.45
	1978-1979		2,720		5.43
1972-1978	1971-1979			6.25	8.12