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| Exhibit No.: | |
| Witness: | Maurice Brubaker |
| Type of Exhibit: | Direct Testimony |
| Issue: | Cost of Service |
| Sponsoring Party: | Praxair, Inc. |
| Case No. | ER-2001-299 |

**Before the Public Service Commission**
**of the State of Missouri**

| | | |
|---|---|---|
| In the Matter of The Empire District Electric Company's tariff sheets designed to implement a general rate increase for retail electric service provided to customers in the Missouri service area of the Company | ) | Case No. ER-2001-299 |

Direct Testimony of

**Maurice Brubaker**

On behalf of

**Praxair, Inc.**

Project 7513
April 2001

FILED
APR 1 0 2001
Missouri Public
Service Commission

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

**Before the Public Service Commission**
**of the State of Missouri**

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**STATE OF MISSOURI** )
) **SS**
**COUNTY OF ST. LOUIS** )

## Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Praxair, Inc. in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2001-299.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things they purport to show.

Maurice Brubaker
Maurice Brubaker

Subscribed and sworn to before this 9th day of April 2001.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2004

Carol Schulz
Notary Public

My Commission Expires February 26, 2004.

**Before the Public Service Commission**
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## Direct Testimony of Maurice Brubaker

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

**Q WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and president of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

**Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of Praxair, Inc. (Praxair). Praxair is a large industrial customer that purchases electricity under Special Transmission Service Contract: Praxair, identified in the tariffs as Schedule SC-P. Approximately 95% of Praxair's requirements are purchased on an interruptible basis. Only 5% is firm power.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to comment on the electric class cost of service study presented by The Empire District Electric Company (Empire or Company), and to present modifications and corrections to Empire's study. I also present an alternative study which I believe is more representative of the responsibility for costs incurred by Empire in serving its various customers. In addition, I will also recommend an alternative allocation of any change in revenues found appropriate for Empire.

## Utility System Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed, or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. For Empire, these characteristics are shown on Schedule 1. This schedule shows the monthly system peak demands for each of the years 1996 through 1999. The red bars show the month in which the annual system peak occurred. The bars with the red tips indicate the extent of load in excess of 90% of the annual peak occurring in any other month. Months where the load did not exceed 90% of the annual peak are shown without the red highlighting. This analysis clearly shows that summer peaks dominate on the Empire system. (This same information is presented in tabular form on Schedule 2.)

Q EARLIER, YOU MENTIONED FIXED OR DEMAND-RELATED COSTS. WHAT ARE THEY AND HOW DO THEY RELATE TO SYSTEM LOADS?

A The fixed or demand related costs for a utility system are generally referred to as capacity costs. As I will discuss below, utilities incur capacity-related costs in order to have sufficient capability to meet peak load requirements imposed on their systems by their customers.

Q **WHAT ARE PRODUCTION AND TRANSMISSION CAPACITY COSTS?**

A Capacity costs are related to the facilities owned and operated by the utility to provide service to customers. The specific cost elements include:

- Return on investment;
- Fixed operation and maintenance (O&M) expenses, consisting of costs that do not vary with the amount of energy generated and sold;
- Depreciation expense; and
- Ad valorem, payroll taxes and income taxes.

Q **WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?**

A The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that caused the utility to incur capacity costs.

Q **WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?**

A Production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class' contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then either the Twelve Coincident Peak (12 CP) or Average and Excess (A&E) methods would be more appropriate.

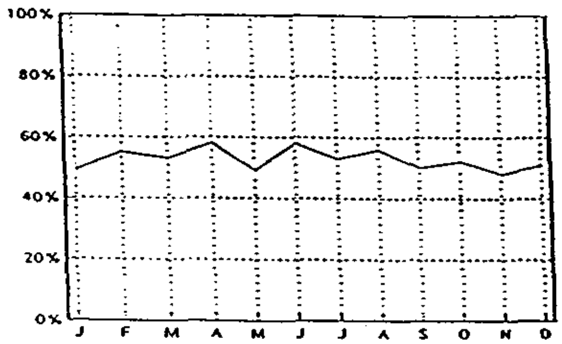
Q **WHAT IS THE A&E METHOD?**

A Average and excess is one of a family of methods which incorporates a consideration of both the maximum rate of use and the duration of use. As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce energy at an absolutely level rate of use. The system "excess" demand is the difference between the actual system peak demand and the average demand. The more energy a class uses in proportion to its average demand—that is, the higher the load factor—the more likely that the class peak demand will be coincident with the system peak demand.

At the limit, a class with a 100% load factor would be 100% certain of being on at the time of the system peak. Moreover, such a customer would not contribute at all to the diversity of the system because the load is the same in all hours. Thus, the "average" component of the A&E method reflects the greater probability that a high load factor customer will contribute to the system peak. The "excess" component, on the other hand, is a measure of the "peakiness" or variability in usage.[1]

**Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?**

A Consider for example two classes that have the following monthly usage patterns.

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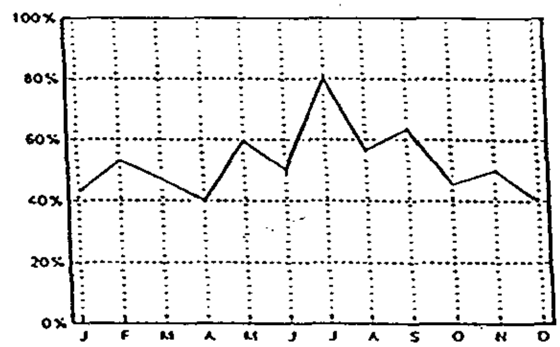


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Both classes use the same total amount of energy and, therefore, have the same average demand. The second class, though, has much greater maximum demand than the first. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment resulting in higher maintenance cost.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).

[1] NARUC Electric Utility Cost Allocation Manual, 1992, Page 81.

**Q WHAT DEMAND ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR USE ON THE EMPIRE SYSTEM?**

A First, in order to reflect cost causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs. Either a coincident peak study, using the demands during the months of July and August, or a version of an average and excess cost of service study that uses peak loads occurring during the summer would be most appropriate to reflect these characteristics on the Empire system. To be conservative, however, I will make my primary recommendation using the traditional average and excess cost allocation methodology.

In addition, the interruptible nature of the Praxair load must be appropriately recognized in any cost of service study. I will elaborate on this distinction, and its importance, later in this testimony.

**Q WHAT ALLOCATION FACTORS HAVE YOU DEVELOPED?**

A These are summarized on Page 1 of Schedule 3. It presents the traditional A&E allocation factor using maximum class peak demands, both as developed by Empire, and as adjusted to recognize the interruptible nature of the Praxair load. For comparison purposes, the schedule also shows the allocation factors for a 2 coincident peak (CP) allocation. Schedule 3 also presents the derivation of each of these allocation factors.

## Cost of Service Analysis

**Q WHAT IS A COST OF SERVICE STUDY?**

A A cost of service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. A cost study is an analysis used to determine each class's responsibility for these costs.

**Q WHAT PROCEDURES ARE USED IN A COST OF SERVICE STUDY?**

A Appendix B outlines the generally-accepted concepts and steps employed in an electric class cost of service study.

**Q IS THE COST OF SERVICE FRAMEWORK DESCRIBED IN APPENDIX B USED THROUGHOUT THE UTILITY INDUSTRY?**

A Yes. In fact, every logical cost analysis must use these procedures of functionalizing costs (into generation, transmission, distribution and so on), classifying them (into demand-related, energy-related and customer-related) and allocating them among classes. There can, of course, be differences in the sequence of the calculations or the analytical structure, but the conceptual framework is always the same.

**Q DOES THE APPLICATION OF THESE GENERAL COSTING PRINCIPLES RESULT IN DIFFERENCES IN THE PER UNIT COST OF SERVING THE VARIOUS TYPES OF CUSTOMERS?**

A Yes. As explained in Appendix B, costs are <u>not</u> allocated on a per kilowatthour sold basis (not even energy-related costs, which recognize the differences in the losses incurred to serve customers at various voltage levels). Most fixed costs are allocated either on a demand or customer basis. Recognizing the different types of costs and the different ways electricity is used by various customers leads to the conclusion that there are significant differences in the cost of serving the various customer classes.

The table below illustrates the cost of service per kilowatthour, based on the average and excess allocation methodology which I will subsequently describe in more detail.

**Cost of Service**
**Expressed Per Kilowatthour**

| | |
|---|---|
| Residential | 8.3¢ |
| Commercial | 8.4¢ |
| General Power | 5.1¢ |
| Large Power | 4.3¢ |
| Praxair | 2.3¢ |
| Total | 6.7¢ |

General power and large power class consumers are less costly to serve because (1) they operate at higher load factors, (2) electricity is generally sold at higher delivery voltages, and (3) they use more electricity per customer. These differentials suggest that there is nothing fundamentally wrong or inequitable about some customers paying higher/lower average rates than others. Appendix B elaborates on these differences. Praxair is even less costly to serve because it is 95% interruptible.

Q **HAVE YOU ANALYZED EMPIRE'S CLASS COST OF SERVICE STUDY?**

A Yes. Empire has used a traditional type of A&E cost of service study. There were a number of inconsistencies and errors in Empire's filed cost of service study which we have identified and discussed with Empire. Corrections to that study have been made. These corrections included a mis-statement of the accumulated reserves for depreciation within the distribution function and a mis-statement of the revenues collected from Praxair. The results of the corrected version of the Company study are summarized on Schedule 4 of my Exhibit.

**Q ARE THERE ANY INTERNAL METHODOLOGICAL PROBLEMS WITH EMPIRE'S STUDY?**

A Yes. As previously mentioned, Praxair's load is approximately 95% interruptible. The Company's study attempted to recognize this by adjusting Praxair's revenues to equal what they would have been had the load been served on a firm basis, and also allocated costs to Praxair as if it were totally firm. The result of this study would be an indication of the cost to Empire of serving Praxair on a firm basis, and the rate of return that Praxair would be providing if it were taking firm service. The problem with the study is that Praxair is not taking firm service; 95% of its power requirements are taken on an interruptible basis and can be withdrawn by Empire on terms which are very liberal to Empire.

**Q HOW SHOULD EMPIRE'S COST OF SERVICE STUDY BE ADJUSTED TO APPROPRIATELY REFLECT THE NATURE OF THE POWER TAKEN BY PRAXAIR?**

A The study should be adjusted to allocate costs to Praxair based only on that portion of its load which is firm. The actual revenues received from Praxair, which are lower than firm service revenues because of the interruptible credit, should be used in the cost of service study.

**Q PLEASE EXPLAIN IN MORE DETAIL THE NATURE OF INTERRUPTIBLE POWER AND HOW IT BENEFITS THE UTILITY SYSTEM AND THE OTHER CUSTOMERS?**

A Interruptible power is power that is provided to customers on the basis that its availability can be withdrawn for the benefit of service to firm customers, if the power is required to provide reliable service to firm customers. In other words, interruptible power is sold to the interruptible customers when it is not needed to supply firm load customers. The conditions under which the interruptible power may be withdrawn from the interruptible customer are defined in the tariffs and contracts under which the utility sells power on an interruptible basis.

From a planning perspective, a utility does not need to plan generation resources to serve interruptible load. Rather, the planning process basically focuses on the needs of firm customers. In the case of strongly summer peaking companies (like Empire) it is the summer peak loads of the customers which drive the amount of generating resources required to provide firm service to firm customers. Having arranged for that amount of generation resources (installed generation capacity and/or firm purchased power) necessary to provide firm service, a utility is able to sell power on an interruptible basis to customers willing to accept less than firm service. The power is sold to the interruptible customers when it is not needed to supply the needs of the firm customers. This obviously allows the utility to operate with a smaller amount of generation capacity than would be the case if all load were served on a firm basis. Therefore, in performing a cost of service study, interruptible customers should not be allocated any responsibility for demand-related generation investment or purchased power costs, since their interruptible load does not cause these costs to be incurred.

Empire has the right to interrupt the Praxair load up to 400 hours in any rolling 12-month period. In addition, there is no limitation on the number of hours of interruption in a given day.

Q HAVE YOU DEVELOPED A COST OF SERVICE ALLOCATION WHICH YOU BELIEVE IS MORE REALISTIC?

A Yes, I have. This is shown on Schedule 5. This study uses the same basic A&E allocation methodology as the revised Company study shown in Schedule 4, except that it explicitly recognizes the interruptible nature of Praxair's load. In this cost of service study, the Praxair load (for purposes of allocating generation fixed costs) is established at the 300 kW firm level. The transmission allocation is the same as in the Company study, and does not provide any reduction from that which is allocable on a firm basis.

Q PLEASE EXPLAIN SCHEDULE 5.

A Schedule 5 is the full printout of our preferred A&E cost of service study. The summary page shows the key statistics, including rate base, revenues, expenses, operating income, rate of return and relative rate of return.

Line 11 on the summary shows the deviation of each class from cost of service at present rates. Taking the residential class as an example, it would require an increase of approximately $10.8 million or 11% to reach cost of service at present rates. The commercial service class would require a decrease of $2.6 million or 11%; while the general power class would require a decrease of $6.3 million or 18% to reach cost of service. Praxair would require a decrease of $537,000 or 33%.

Q WHAT ELSE IS SHOWN AT THE BOTTOM OF THIS SCHEDULE?

A Also shown at the bottom of the schedule are the increases or decreases in revenue, compared to proposed revenues, required to equal cost of service at Empire's claimed revenue requirement. For the residential class this is an increase of $9.8 million in addition to the proposed across-the-board increase. The commercial service class would require a decrease of $1.6 million, the general power class would require a decrease of $5.6 million, and the large power class would require a decrease of $1.4 million. Praxair would require a decrease of $554,000.

**Q WHAT IS SHOWN ON SCHEDULE 6?**

A Schedule 6 presents a summary of the 2-coincident peak cost of service study. For the major customer classes the results are quite similar to the results of the A&E study.

**Adjustment of Class Revenues**

**Q WHAT SHOULD BE THE PRIMARY BASIS FOR ESTABLISHING CLASS REVENUE REQUIREMENTS AND DESIGNING RATES?**

A Cost should be the primary factor used in both steps.

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the basis used to establish the revenues collected from each customer class and to design rate schedules.

Although factors such as simplicity, gradualism and ease of administration may also be taken into account, the basic starting point and guideline throughout the process should be cost of service. To the extent practicable, rate schedules should be structured and designed to reflect the important cost-causative features of the service provided, and to collect the appropriate cost from the customers within each class or rate schedule, based upon the individual load patterns exhibited by those customers.

**Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT COST BE USED AS THE PRIMARY FACTOR FOR THESE PURPOSES?**

A The basic reasons for using cost as the primary factor are equity, conservation, and engineering efficiency (cost-minimization).

**Q PLEASE EXPLAIN HOW EQUITY IS ACHIEVED BY BASING RATES ON COST.**

A When rates are based on cost, each customer pays what it costs the utility to provide service to that customer; no more and no less. If rates are based on other than cost factors, then some customers will pay the costs attributable to providing service to other customers–which is inherently inequitable.

**Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?**

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be induced to use electricity inefficiently in response to the distorted rate design signals they receive.

**Q WILL COST-BASED RATES ASSIST IN THE DEVELOPMENT OF COST-EFFECTIVE DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS?**

A Yes. The success of DSM depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is subsidized by other customers; that is, the bill is based on rates which are below cost, that customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

**Q HOW DO COST-BASED RATES ACHIEVE THE COST-MINIMIZATION OBJECTIVE?**

A When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

If a utility attempts to extract a disproportionate share of revenues from a class that has alternatives available, then the utility will be faced with the situation where it must discount the rates or lose the load, either in part or in total. To the extent that the load could have been served more economically by the utility, then either the other customers of the utility or the stockholders (or some combination of both) will be worse off than if the rates were properly designed on the basis of cost.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from large customers and high load factor customers. To the extent that these customers may have lower cost alternatives than do the smaller or the low load factor customers, the same problems noted above are created.

**Q HAVE YOU PREPARED RECOMMENDATIONS FOR THE ALLOCATION OF REVENUE ADJUSTMENTS (INCREASES OR DECREASES) AMONG CUSTOMER CLASSES?**

A Yes, I have. This appears on Schedule 7.

**Q WHAT RANGE OF REVENUE CHANGES HAVE YOU CONSIDERED?**

A I have prepared a schedule which illustrates how revenue changes in the range of a $15 million increase to a $40 million increase should be apportioned.

**Q WHAT IS THE BASIS FOR YOUR RECOMMENDED REVENUE ALLOCATION?**

A My primary objective was to move rates closer to cost of service, while being mindful of the need to moderate increases to those customer classes that would require their rates to be adjusted significantly more than the average. The classes requiring substantially above average increases to achieve cost of service are the residential, commercial small heat, power furnace and lighting classes.

In the context of an overall increase of 20% ($40 million) I decided, for impact reasons, to limit the maximum increase to any class to 25%. Accordingly, Schedule 7 shows that these four classes received a 25% increase. (The CSH class receives 24% because that is what is required to move it to cost of service).

Next, I identified those classes whose required changes were negative, or a small positive number. I assigned to them an increase equal to one-half of the overall increase. These are the general power, Praxair and miscellaneous classes. The balance of the increase was apportioned to the remaining customer classes who required increases less than the average, but more than the prior group. The overall average increase to these customers was approximately 18%.

With a $15 million increase, or 7.5%, I followed the same pattern but allowed the maximum increases to be relatively larger than in the case when the increase was 20%. In other words, the 25% increase to the low rate of return classes is approximately 1.25 times the overall system average of 20%. For an increase of 7.5%, I limited the increase to any individual class to 11%, which is approximately 1.45 times the overall system average. The classes requiring decreases or increases close to zero were assigned a 2.5% increase and the balance or residual was assigned to other customer classes with the result that they would receive an increase of approximately 4.5%.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

## Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, telephone and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

We have prepared many studies relating to electric, steam, gas and water properties, including cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

During the past five years, Brubaker & Associates, Inc. and its predecessor firm has participated in over 500 major utility rate cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates. Rate cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

In addition to our main office in St. Louis, the firm also has branch offices in Kerrville, Texas; Plano, Texas; Denver, Colorado; and Chicago, Illinois.

## COST OF SERVICE
## DETERMINATION PROCEDURES

### Overview

The objective of *cost allocation* is to determine what proportion of the utility's total revenue requirement should be recovered from each customer class. As an aid to this determination, cost of service studies are usually performed to determine the portions of the total costs that are incurred to serve each customer class. The cost of service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design. For many regulators, cost-based rates are an expressed goal. To better understand cost allocation and cost of service studies, it is important to first become fully acquainted with the commodity, electricity.

### Electricity Fundamentals

Electricity is different from most other commodities purchased by consumers. For example:

- It cannot be stored; must be delivered as product;
- It must be delivered to the customer's home or place of business;
- The delivery occurs instantaneously when and in the amount needed by the customer; and
- Both the total quantity used (energy or kWh) by a customer and the rate of use (demand or kW) are important.

These unique characteristics differentiate electric utilities from other service-related industries.

The service provided by electric utilities is multi-dimensional. First, unlike most vital services, electricity must be delivered at the place of consumption – homes, schools, businesses, factories – because this is where the lights, appliances, machines, air conditioning, etc. are located. Thus, every utility must provide a path through which electricity can be delivered regardless of the customer's **demand** and **energy** requirements.

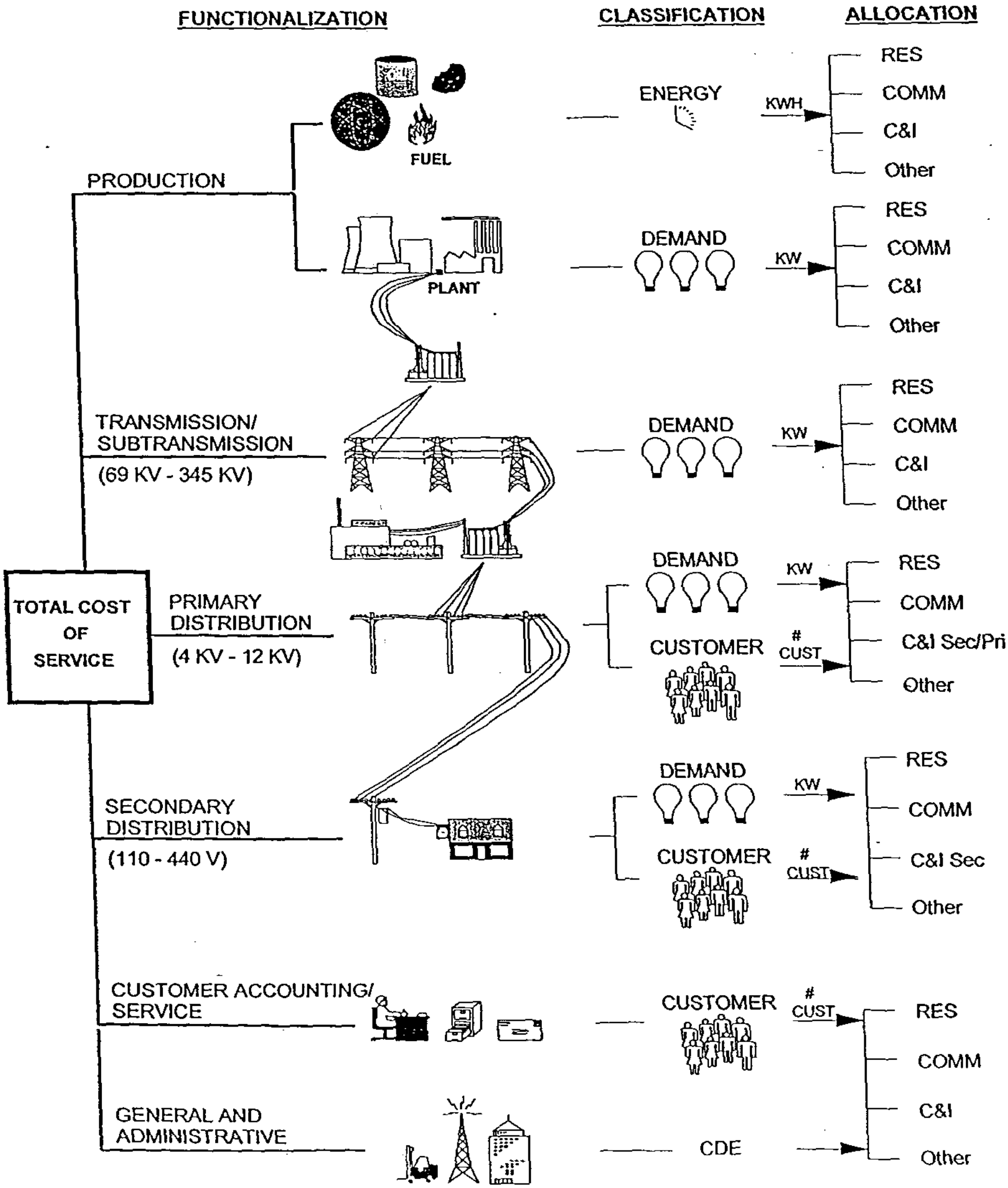
Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, space conditioning, and to operate various appliances. At any instant, several appliances may be operating (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and when reflects the second dimension of utility service–the rate of electricity use or **demand**. The demand imposed by customers is an especially important characteristic because it is the maximum demands determine how much capacity the utility is obligated to provide. Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can be safely imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 900 megawatts (MW) of electricity, the utility must have at least 900 MW of generation, plus additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and heating and air conditioning systems heat and cool our homes, schools, offices, and factories.

Satisfying customers' demand for electricity over time–providing **energy**–is the third dimension of utility service. It is also the dimension with which we are most familiar because people often think of electricity simply in terms of kilowatthours. To see one reason why this isn't so, let's take a more familiar commodity–bananas, for example.

The bananas we buy at the supermarket for about 90¢ a pound might originally come from Honduras where they are bought for about 25¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to this country and distributing them in bulk to wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 25¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few bananas as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the fruit itself, but the service of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk at the dock, they would be still cheaper.

As illustrated in the diagram on page 4, electric utilities are similar, except that in most cases a single company handles everything from production on down through wholesale (bulk and area transmission) and retail (distribution to homes and stores). The crucial difference is that, unlike banana producers and distributors, electric utilities have an obligation to provide continuous reliable service. The obligation is a quid-pro quo for having an exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kilowatthour) requirements of its customers, the obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

# PRODUCTION AND DELIVERY OF ELECTRICITY




Appendix B
Maurice Brubaker
Page 4

## A Closer Look At The Cost of Service Study

To the extent possible, the unique characteristics that differentiate electric utilities from other service-related industries should be recognized in determining the cost of providing service to each of the various customer classes. The basic procedure for conducting a class cost of service study is simple. In an allocated cost of service study, we identify the different types of costs (**functionalization**), determine their primary causative factors (**classification**) and then apportion each item of cost among the various rate classes (**allocation**). Adding up the individual pieces gives the total cost for each class.

### Functionalization

Identifying the different levels of operation is a process referred to as **functionalization**. The utility's investment and expenses are separated by function (production, transmission, etc.). To a large extent, this is done in accordance with the Uniform System of Accounts.

Referring to page 4, at the top level there is generation. The next level is the extra high voltage transmission and subtransmission system (34,500 to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution–4,160 to 12,000 volts. Finally, the voltage is stepped down by pole transformers at the "secondary" level to 110/220 volts used to serve homes, barber shops and the like. Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltage.

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a banana is a banana." It's true in one sense, but when you buy a kilowatthour at home you're not only buying the energy itself but also the service of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like large power service customers–pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment.)

## Classification

Once the costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as **classification**. Costs are classified as demand-related, energy-related or customer-related.

Looking at the production function, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 900 megawatts–it must install enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable). There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance expenses, taxes and insurance) **are fixed;** that is, **they do not vary with the amount of kilowatthours generated and sold**. These fixed costs do, however, vary with the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned–and therefore the amount of fuel expense–is closely related to the amount of energy (number of kilowatthours) that customers use. Therefore, fuel expense is an energy-related cost.

Some O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served at any moment.

Customer-related costs are a third major classification category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per month per customer. Less obvious examples of customer-related costs may include the investment in-other distribution accounts.

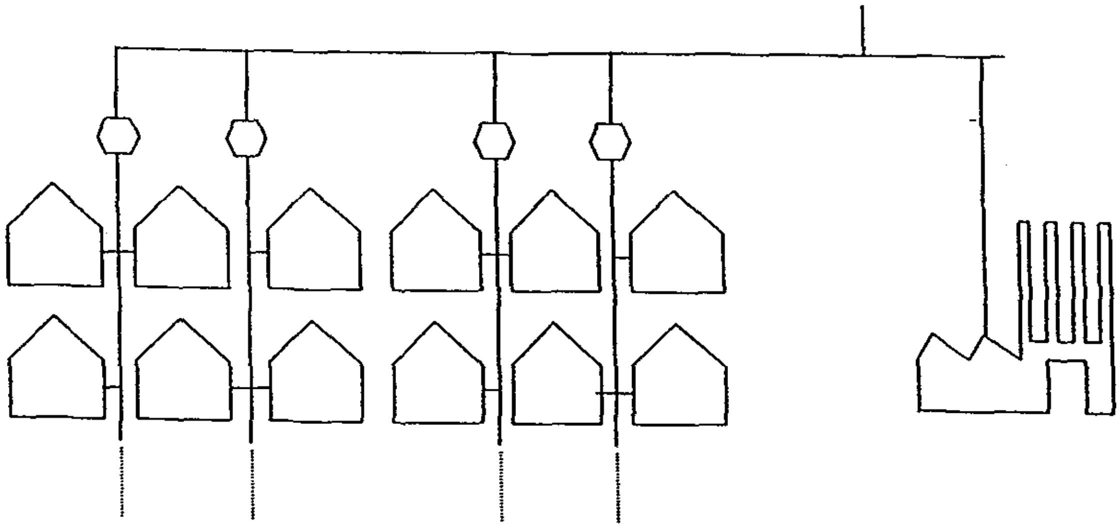
A certain portion of the cost of the distribution system–poles, wires and transformers–is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

The diagram on page 8, for example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), even though the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

## Classification of Distribution Investment



Total Demand = 120 kW
Class A

Total Demand = 120 kW
Class B

## Demand vs. Energy Costs

The difference between demand-related and energy-related costs also explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, the diagram on page 10, compares the electrical requirements of two customers, A and B, each using 100-watt light bulbs.

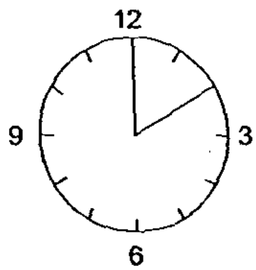
Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy–1,000 watthours or 1 kilowatthour (kWh). However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kilowatts (kW), than Customer who demanded only 200 watts per hour or 0.2 kW.

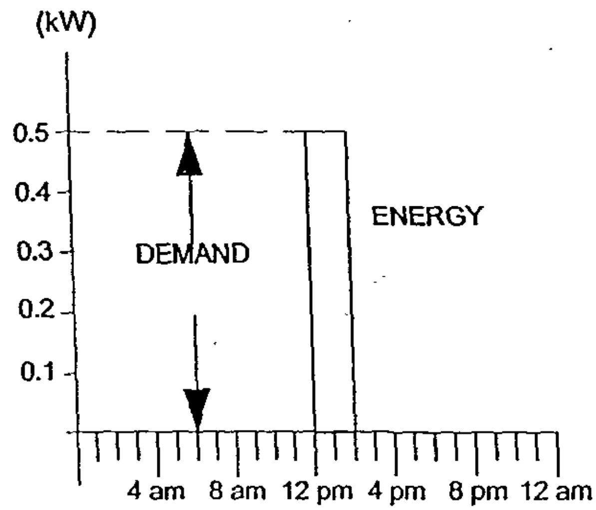
Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 time Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

In general, a customer who has a high load factor (defined as the average rate of usage divided by the peak rate of usage) will be cheaper to serve per kWh than a customer with a low load factor, regardless of size. Consider the analogy of a rental car which costs \$40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be \$2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the average total cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kilowatthour will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industries generally have higher load factors than residential or general service customers, they are less costly to serve on a per-kilowatthour basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

# DEMAND VS. ENERGY

## CUSTOMER A




**ENERGY:** 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

**DEMAND:** 500 watts = 0.5 kW

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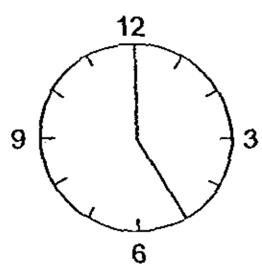
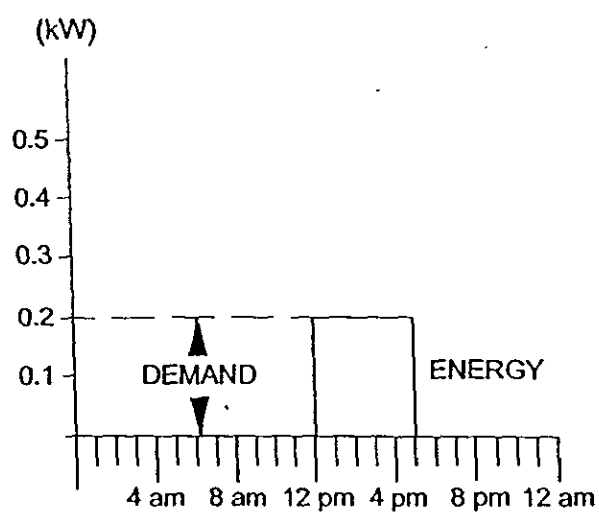
## CUSTOMER B




**ENERGY:** 200 watts x 5 hours = 1,000 watthours = 1.0 kWh

**DEMAND:** 200 watts = 0.2 kW

## Allocation

The final step in the cost of service analysis is the **allocation** of the costs to the customer classes. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor simply measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. A sample calculation for Empire is shown in Table 1.

**TABLE 1**
**Energy Allocation Factor**

| Rate Class | Energy Generated (MWh) (1) | Allocation Factor (2) |
|---|---|---|
| Residential | 1,677,744 | 41.43% |
| Commercial | 354,741 | 8.76% |
| General Power | 754,409 | 18.63% |
| Large Power | 719,814 | 17.77% |
| Praxair | 56,758 | 1.40% |
| Other | 486,395 | 12.01% |
| Total | 4,049,860 | 100.00% |

For demand-related costs, we construct an allocation factor by looking at the important class demands. Table 2 shows the calculation of this factor for Empire. In this table for the production demand allocation factor, Praxair's firm demand of 300 kW is utilized because this is the amount that Empire is obligated to serve.

In the case of the transmission allocation factor we have used the maximum demand of Praxair because we would not expect Empire to curtail based on transmission conditions.

**TABLE 2**

**Demand Allocation Factor**
**Production System**

| Rate Class | Production A&E (MW) | Allocation Factor |
|---|---|---|
| | (1) | (2) |
| Residential | 401.4 | 48.77% |
| Commercial | 84.8 | 10.30% |
| General Power | 131.8 | 16.01% |
| Large Power | 95.5 | 11.61% |
| Praxair | 0.3 | 0.04% |
| Other | 109.2 | 13.27% |
| Total | 822.9 | 100.00% |

**TABLE 3**

**Demand Allocation Factor**
**Transmission System**

| Rate Class | Transmission A&E (MW) | Allocation Factor |
|---|---|---|
| | (1) | (2) |
| Residential | 398.1 | 48.38% |
| Commercial | 84.1 | 10.22% |
| General Power | 130.5 | 15.85% |
| Large Power | 94.4 | 11.47% |
| Praxair | 7.6 | 0.93% |
| Other | 108.2 | 13.15% |
| Total | 822.9 | 100.00% |

**Making the Cost of Service Study–Summary**

The cost of service procedure involves three steps:

(1) Functionalization–Identify the different functional "levels" of the system;

(2) Classification–Determine, for each functional type, the primary cause or causes of that cost being incurred;

(3) Allocation–Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

Table 4 shows the results of a cost of service study in condensed, summary form. The revenues from each class can be calculated by taking the billing units times the current rate. The expenses (including taxes) for each class are allocated. Subtracting the expenses from the revenue gives the net operating income (also called return) from each class. Dividing this net operating income by the allocated rate base gives the rate of return (return on investment) for each class.

TABLE 4

**Summary of Empire's Cost of Service Study at Present Rates (Dollars in Thousands)**

| Rate Class | Revenues (1) | Expenses (2) | Return (3) | Rate Base (4) | Rate of Return (5) |
|---|---|---|---|---|---|
| Residential | $ 97,649 | $ 91,548 | $ 6,101 | $ 274,192 | 2.23% |
| Commercial | 23,001 | 18,792 | 4,209 | 55,899 | 7.53% |
| General Power | 36,123 | 29,164 | 6,958 | 66,669 | 10.44% |
| Large Power | 25,038 | 23,012 | 2,026 | 43,512 | 4.66% |
| Praxair | 1,598 | 1,216 | 382 | 1,114 | 34.33% |
| Other | 27,149 | 23,245 | 3,903 | 66,392 | 5.88% |
| Total | $ 210,558 | $ 186,977 | $ 23,580 | $ 507,777 | 4.64% |

This cost study shows two things. First, it shows that at present rates not all classes are equally profitable. In other words, some classes pay a portion of the costs incurred to serve other customer classes. Second, it provides the information from which we can calculate the necessary increase in revenues from each class to achieve cost-based revenues.

Table 5 shows each class's cost-based revenue requirement. This amount is calculated by summing the required return (rate base times system rate of return) and expenses. Expressed on a cents per kWh basis, the residential and the commercial classes have an above-average cost per kWh while the other major classes have below-average costs per kWh.

**TABLE 5**

**Class Revenue Requirement**
**Average and Excess Method**
**(Dollars in Thousands)**

| Rate Class | Cost-Based Revenue (1) | Energy Sales (MWh) (2) | Cost per kWh (3) |
|---|---|---|---|
| Residential | $ 121,588 | 1,457,518 | 8.34 |
| Commercial | 24,789 | 295,953 | 8.38 |
| General Power | 36,203 | 717,446 | 5.05 |
| Large Power | 27,617 | 636,465 | 4.34 |
| Praxair | 1,285 | 55,105 | 2.33 |
| Other | 29,901 | 436,954 | 6.84 |
| Total | $ 241,383 | 3,599,441 | 6.71¢ |

The reasons for these differences are (1) load factor, (2) delivery voltage, and (3) size.

The general power and large power customers and Praxair have higher load factors, as shown in Schedule 1 of Appendix B. Consequently, the capital costs related to production and transmission are spread over a greater number of kilowatthours than is the case for lower load factor classes.

In addition, these customers take service at a higher voltage level. This means that they avoid the costs associated with lower voltage distribution. Nor does Empire incur as many losses to serve them.

The per capita sales to these classes are also much greater than to the other classes. Empire sells 595,391 and 17,679,585 kilowatthours per general power and large power customer, respectively, but only 13,425 kilowatthours per residential customer, or between 44 and 1317 times more per capita, as shown in Schedule 2 of Appendix B. The customer-related costs to serve the former are not 44 to 1317 times the customer-related costs to serve the residential customer.

These differences in the service and usage characteristics–load factor, delivery voltage and size–result in a lower per unit cost to serve customers operating at a higher load factor, taking service at higher delivery voltage and purchasing a larger quantity of power and energy at a single delivery point. As can be seen from Schedule 3 of Appendix B, the rate base and total operating expenses per kilowatthour sold to large power customers are lower than the corresponding per kilowatthour costs to serve the other rate classes.

And, the cost to serve Praxair is even lower because, in addition to being a large customer served at high voltage, 95% of its power requirements are taken on an interruptible basis; with only 5% being taken on a firm basis.

Thus, electricity is more than just providing kilowatthours. It is wrong to conclude that some customers are "getting a break" just because their average rates are lower than the rates of other customers paying on a per kilowatthour basis. The lower costs shown in Schedule 3 of Appendix B justify setting rates to general power and large power customers, and Praxair, which are lower per kilowatthour than the rates charged to other rate classes.

# THE EMPIRE DISTRICT ELECTRIC COMPANY

**Comparative Load Factors**
**Year Ended December 31, 2000**

| Line | Rate Classes | | Rates | Energy Generated (MWh) | Transmission Average & Excess Demand (MW) | Load Factor |
|---|---|---|---|---|---|---|
| | | | (1) | (2) | (3) | (4) |
| 1 | Residential | RG | 41,43,45 | 1,677,744 | 398.1 | 48% |
| 2 | Commercial | CB | 25 | 354,741 | 84.1 | 48% |
| 3 | Commercial | SH | 26 | 127,841 | 31.2 | 47% |
| 4 | General Power | GP | 68 | 754,409 | 130.5 | 66% |
| 5 | El. Furnace | PF | 70 | 2,139 | 1.8 | 13% |
| 6 | Praxair | | 61 | 56,758 | 7.6 | 85% |
| 7 | Total El Build | TEB | 63 | 311,709 | 61.3 | 58% |
| 8 | Feed Mill | PFM | 67 | 1,084 | 0.5 | 26% |
| 9 | Large Power | LP | 77 | 719,814 | 94.4 | 87% |
| 10 | Misc Lights | MS | 33 | 478 | 0.1 | 95% |
| 11 | Other Lights | | 36,37,38,39 | 43,144 | 13.4 | 37% |
| 12 | Total Retail | | | 4,049,860 | 822.9 | 56% |

**Appendix B**
**Schedule 1**

# THE EMPIRE DISTRICT ELECTRIC COMPANY

**Kilowatthours Sold per Customer**
**Year Ended December 31, 2000**

| Line | Rate Classes | | Rates (1) | Energy Sold (MWh) (2) | Number of Customers (3) | Generation per 100 kWh Sold (4) |
|---|---|---|---|---|---|---|
| 1 | Residential | RG | 41,43,45 | 1,457,518 | 108,566 | 13,425 |
| 2 | Commercial | CB | 25 | 295,953 | 16,290 | 18,168 |
| 3 | Commercial | SH | 26 | 111,819 | 2,751 | 40,647 |
| 4 | General Power | GP | 68 | 717,446 | 1,205 | 595,391 |
| 5 | El. Furnace | PF | 70 | 2,045 | 3 | 681,769 |
| 6 | Praxair | | 61 | 55,105 | 1 | 55,104,533 |
| 7 | Total El Build | TEB | 63 | 288,576 | 662 | 435,915 |
| 8 | Feed Mill | PFM | 67 | 1,174 | 19 | 61,815 |
| 9 | Large Power | LP | 77 | 636,465 | 36 | 17,679,585 |
| 10 | Misc Lights | MS | 33 | 445 | 1 | 445,438 |
| 11 | Other Lights | | 36,37,38,39 | 32,893 | 969 | 33,946 |
| 12 | Total Retail | | | 3,599,441 | 130,503 | 27,581 |

**Appendix B**
**Schedule 2**

## THE EMPIRE DISTRICT ELECTRIC COMPANY

**Allocated Rate Base and Operating Expense**
**per kWh Sold**
**Cost of Service Study**
**Average and Excess Method**
**Year Ended December 31, 2000**

| Line | Rate Classes | | Rates (1) | Energy Sold (MWh) (2) | Rate Base Amount (000) (3) | Rate Base per kWh (4) | Total Operating Expense Including Income Taxes Amount (000) (5) | Total Operating Expense Including Income Taxes per kWh (6) |
|---|---|---|---|---|---|---|---|---|
| 1 | Residential | RG | 41,43,45 | 1,457,518 | $ 274,192 | 18.81 ¢ | $ 91,548 | 6.28 ¢ |
| 2 | Commercial | CB | 25 | 295,953 | 55,899 | 18.89 | 18,792 | 6.35 |
| 3 | Commercial | SH | 26 | 111,819 | 17,812 | 15.93 | 6,285 | 5.62 |
| 4 | General Power | GP | 68 | 717,446 | 66,669 | 9.29 | 29,164 | 4.07 |
| 5 | El. Furnace | PF | 70 | 2,045 | 665 | 32.54 | 201 | 9.84 |
| 6 | Praxair | | 61 | 55,105 | 1,114 | 2.02 | 1,216 | 2.21 |
| 7 | Total El Build | TEB | 63 | 288,576 | 31,830 | 11.03 | 13,054 | 4.52 |
| 8 | Feed Mill | PFM | 67 | 1,174 | 280 | 23.87 | 92 | 7.85 |
| 9 | Large Power | LP | 77 | 636,465 | 43,512 | 6.84 | 23,012 | 3.62 |
| 10 | Misc Lights | MS | 33 | 445 | 48 | 10.76 | 18 | 4.11 |
| 11 | Other Lights | | 36,37,38,39 | 32,893 | 15,756 | 47.90 | 3,594 | 10.93 |
| 12 | Total Retail | | | 3,599,441 | $ 507,777 | 14.11 | $ 186,977 | 5.19 |

Before the
Missouri Public Service Commission

Case No. ER-2001-299

## The Empire District Electric Company

# Schedules Accompanying the

# Direct Testimony of

# Maurice Brubaker