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|---|---|
| Exhibit No.: | |
| Witness: | Maurice Brubaker |
| Type of Exhibit: | Direct Testimony |
| Issues: | Cost of Service, Revenue Allocation, and Rate Design (Part 1: Other than Fuel Adjustment Clause) |
| Sponsoring Party: | Missouri Industrial Energy Consumers |
| Case No.: | ER-2008-0318 |

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| **In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.** | )<br>)<br>)<br>)<br>)<br>) | **Case No. ER-2008-0318** |

Direct Testimony and Schedules of

**Maurice Brubaker**

**on Cost of Service, Revenue Allocation and Rate Design**

**(Part 1: Other than Fuel Adjustment Clause)**

On Behalf of

**Missouri Industrial Energy Consumers**

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

Project 8983
September 11, 2008

**NON-PROPRIETARY VERSION**

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| **In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.** | ) | **Case No. ER-2008-0318** |

**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 the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2008-0318.

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

M E Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 10th day of September, 2008.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2011
Commission # 07024862

Tammy S Klossner
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
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| **In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.** | **)<br>)<br>)<br>)<br>)<br>)** | **Case No. ER-2008-0318** |

## 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 direct testimony on revenue requirement issues.

**Q ON WHOSE BEHALF ARE YOU PRESENTING THIS DIRECT TESTIMONY ON COST OF SERVICE AND RATE DESIGN ISSUES?**

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers (MIEC). I am simultaneously submitting a separate volume of testimony which addresses fuel adjustment issues.

**Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A The purpose of my testimony is to present the results of an electric system class cost of service study for AmerenUE, to explain how the study should be used, and to recommend a cost-based revenue neutral adjustment to class revenues.

**Q HOW IS YOUR TESTIMONY ORGANIZED?**

A First, I present an overview of cost of service principles and concepts. This includes a description of how electricity is produced and distributed as well as a description of the various functions that are involved; namely, generation, transmission and distribution. This is followed by a discussion of the typical classification of these functionalized costs into demand-related costs, energy-related costs and customer-related costs.

With this as a background, I then explain the various factors which should be considered in determining how to allocate these functionalized and classified costs among customer classes.

Finally, I present the results of the detailed cost of service analysis for AmerenUE. This cost study indicates how individual customer class revenues compare to the costs incurred in providing service to them. This analysis and interpretation is then followed by recommendations with respect to the alignment of class revenues with class costs.

# SUMMARY

**Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.**

A My testimony and recommendations may be summarized as follows:

1. Class cost of service is the most important guideline for establishing the level of rates charged to customers.

2. AmerenUE exhibits significant summer peak demands.

3. There are two generally accepted methods for allocating generation and transmission fixed costs that would apply to AmerenUE. These are the coincident peak methodology and the average and excess (A&E) methodology.

4. For AmerenUE's generation and transmission system, I recommend using an A&E demand methodology. Specifically, an annual non-coincident peak A&E method which uses class peak demands from the summer peak month and class annual energy consumption. The single annual non-coincident peak (NCP) is appropriate for this test year and necessary to capture the peak which drives capacity additions.

5. The A&E methodology appropriately considers both class maximum demands and class load factor, as well as diversity between class peaks and the system peak.

6. AmerenUE's cost of service study contains several deficiencies including: (1) use of a Four Non-Coincident Peak Average and Excess (4 NCP A&E) allocation method; (2) allocation of transmission costs using 12 monthly coincident peaks; (3) allocation of a significant proportion of non-fuel production expenses on energy; and (4) an inappropriate allocation of off-system sales.

7. More reasonable cost of service studies, which I present and summarize on Schedules MEB-COS-4 and MEB-COS-5, show how class revenues compare to cost of service.

8. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6.

9. Any decrease or increase found appropriate for Rate 11 (Large Primary Service) should be applied as a uniform percentage decrease or increase to the existing charges in the tariff.

# COST OF SERVICE PROCEDURES

## Overview

**Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.**

A 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 interpret cost allocation and cost of service studies, it is important to understand the production and delivery of electricity.

## Electricity Fundamentals

**Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?**

A No. Electricity is different from most other goods or services purchased by consumers. For example:

- It cannot be stored; must be delivered as produced;
- 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 <u>and</u> 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 at any point in time.

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 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 safely be 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 9,000 megawatts (MW) of electricity, the utility must have at least 9,000 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 air conditioning systems 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 many people are most familiar, because people often think of electricity simply in terms of kWhs.

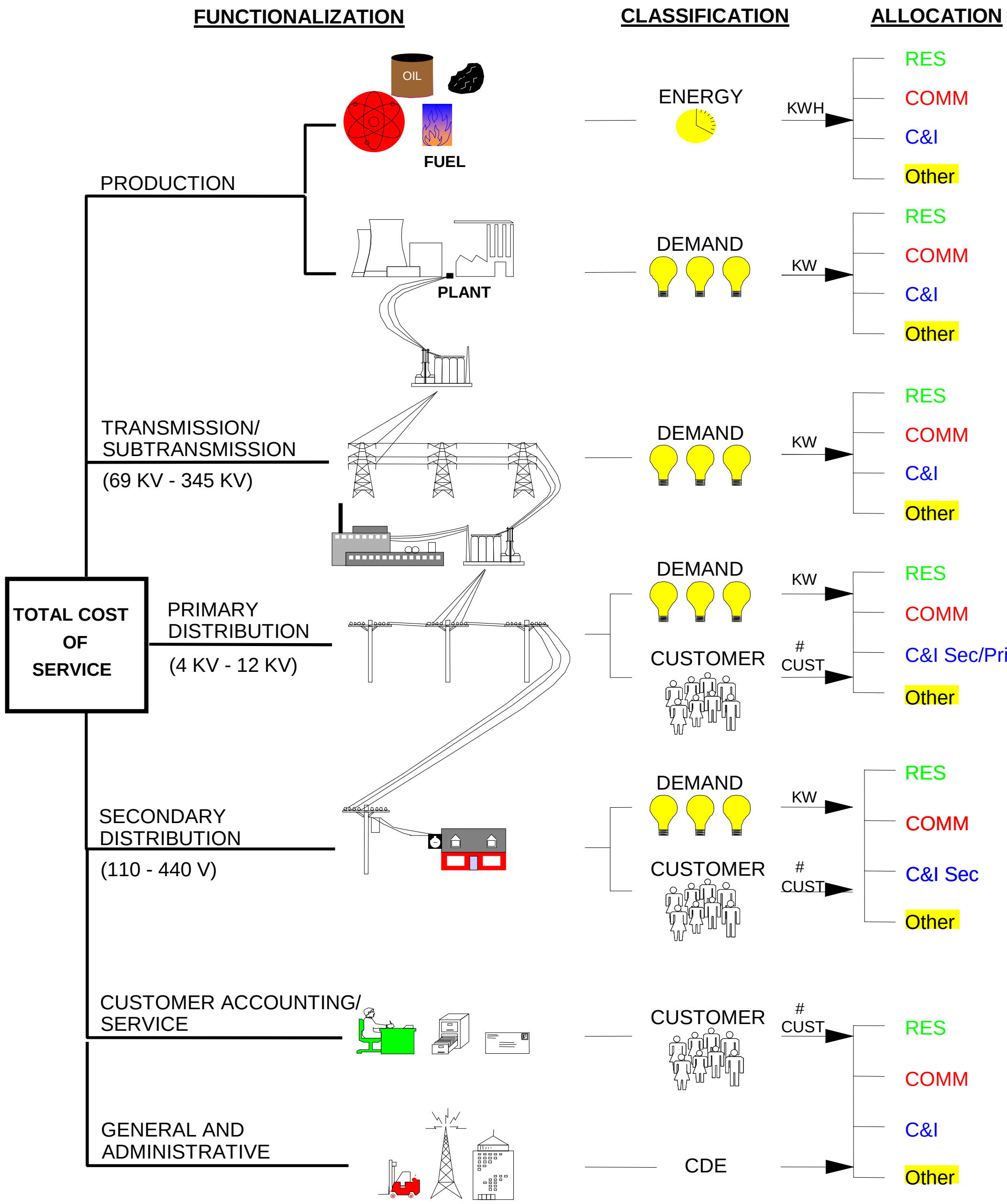
To see one reason why this isn't so, consider a more familiar commodity – tomatoes, for example.

The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ 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 tomatoes 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 vegetable itself, but the <u>service</u> 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 in Florida, they would be even cheaper.

As illustrated in Figure 1, electric utilities are similar, except that in most cases (including Missouri), 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 producers and distributors of tomatoes, electric utilities have an obligation to provide continuous reliable service. The obligation is assumed in return for the exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kWh) 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.

## Figure 1

## PRODUCTION AND DELIVERY OF ELECTRICITY



## A CLOSER LOOK AT THE COST OF SERVICE STUDY

**Q PLEASE EXPLAIN HOW A COST OF SERVICE STUDY IS PREPARED.**

A 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 customer class.

### Functionalization

**Q PLEASE EXPLAIN FUNCTIONALIZATION.**

A 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 Figure 1, 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, barbershops 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 tomato is a tomato." It's true in one sense, but when you buy a kWh 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 Transmission and Large Primary 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, or pay separately for some services.)

## Classification

**Q WHAT IS CLASSIFICATION?**

A 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 9,000 megawatts – it must install and/or contract for 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, **<u>they do not vary with the amount of kWhs generated and sold</u>**. These fixed costs are determined by 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 kWhs) that customers use. Therefore, fuel expense is an energy-related cost.

Most other 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.

Customer-related costs are the third major 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 customer, per month. 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.

Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

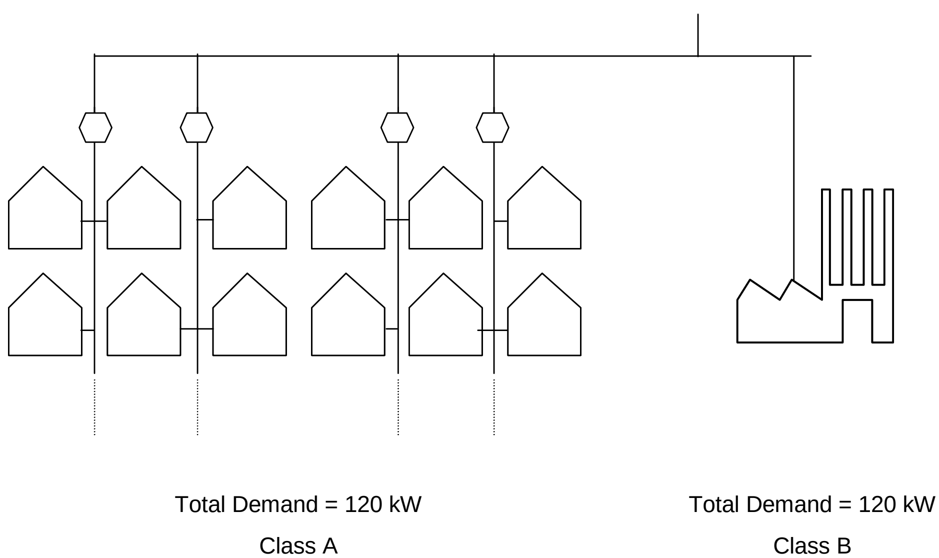
Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that 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 as a result of the need 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.

**Figure 2**

**Classification of Distribution Investment**



## Demand vs. Energy Costs

**Q WHAT IS THE DISTINCTION BETWEEN DEMAND-RELATED COSTS AND ENERGY-RELATED COSTS?**

A The difference between demand-related and energy-related costs explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3, 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 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 times 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.

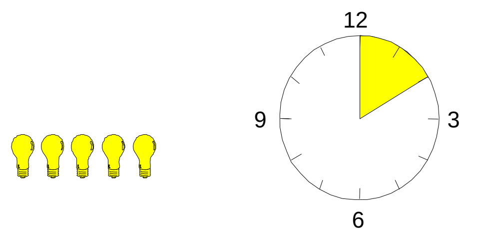
**Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?**

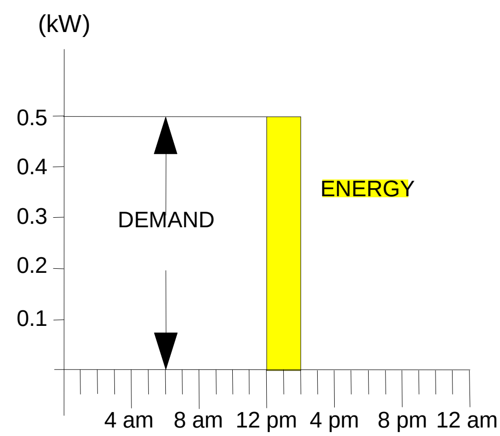
A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each kilowatt of demand imposed on the system is much greater in the case of Customer B.

# Figure 3

# DEMAND VS. ENERGY

## CUSTOMER A

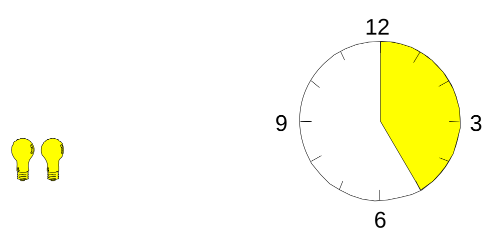


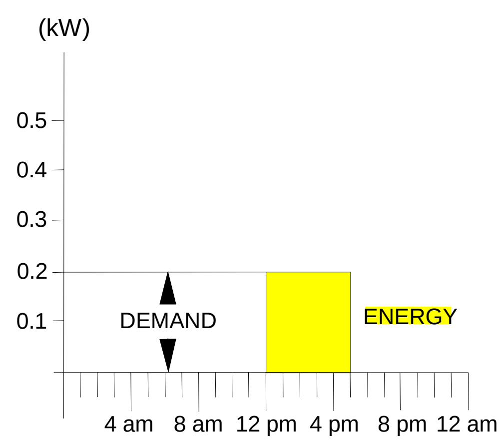




**ENERGY:** 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

**DEMAND:** 500 watts = 0.5 kW

## CUSTOMER B




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

**DEMAND:** 200 watts = 0.2 kW

Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kWh basis, than a customer with a low load factor, irrespective of size.

Consider also 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 <u>average total</u> cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kWh 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 industrial customers generally have higher load factors than residential or commercial customers, they are less costly to serve on a per-kWh 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.

## <u>Allocation</u>

**Q WHAT IS ALLOCATION?**

A 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 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. The energy allocators for AmerenUE's retail customers are shown in Table 1.

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

| Rate Class | Energy Generated (MWh) (1) | Allocation Factor (2) |
|---|---|---|
| Residential | 14,699,462 | 36.40% |
| Small GS | 3,978,667 | 9.85% |
| Large GS/Small Primary | 13,183,663 | 32.65% |
| Large Primary | 4,360,816 | 10.80% |
| Large Transmission | 4,157,133 | 10.30% |
| Total | 40,379,742 | 100.00% |

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 shows the calculation of the factor for AmerenUE. (The selection and derivation of this factor is discussed in more detail on pages 21 to 29.)

**Q DO THE RELATIONSHIPS BETWEEN THE ENERGY ALLOCATION FACTORS AND THE DEMAND ALLOCATION FACTORS TELL US ANYTHING ABOUT CLASS LOAD FACTOR?**

A Yes. Recall that load factor is a measure of the consistency or uniformity of use of demand. Accordingly, customer classes' whose energy allocation factor is a larger percentage than their demand allocation have an above-average load factor, while customers whose demand allocation factor is higher than their energy allocation factor have a below-average load factor.

These relationships are merely the result of differences in how electricity is used. In the case of AmerenUE (as is true for essentially every other utility) the large customer classes have above-average load factors, while the Residential and Small GS customers have below-average load factors. (Load factors are presented in Table 4, which is discussed later.)

**TABLE 2**
**Demand Allocation Factor**
**Production System**

| Rate Class | Production A&E (MW) (1) | Allocation Factor (2) |
|---|---|---|
| Residential | 4,067 | 47.09% |
| Small GS | 968 | 11.21% |
| Large GS/Small Primary | 2,447 | 28.33% |
| Large Primary | 672 | 7.78% |
| Large Transmission | 484 | 5.60% |
| Total | 8,638 | 100.00% |

**Q THE RATES, WHEN EXPRESSED PER KWH, CHARGED TO SMALL PRIMARY, LARGE PRIMARY AND LARGE TRANSMISSION CUSTOMERS ARE CURRENTLY LESS THAN THE RATES CHARGED TO OTHER CUSTOMERS. DOES THE COST OF SERVICE STUDY INDICATE THAT THIS IS APPROPRIATE?**

A Yes. Table 3 shows the cost-based revenue requirement for each customer class. Note that the cost, per unit, to serve the Small Primary, Large Primary and Large Transmission customers is significantly less than the cost to serve the other customers. In fact, similar relationships hold true on any electric utility system.

**TABLE 3**
**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 | $1,035,049 | 13,500,608 | 7.67¢ |
| Small GS | 231,447 | 3,654,176 | 6.33 |
| Large GS/Small Primary | 542,132 | 12,262,006 | 4.42 |
| Large Primary | 145,378 | 4,184,241 | 3.47 |
| Large Transmission | 92,120 | 4,096,908 | 2.25 |
| Total | $2,046,127 | 37,697,940 | 5.43¢ |

As previously discussed, the reasons for these differences are: (1) load factor; (2) delivery voltage; and (3) size.

The Primary and Transmission customers have higher load factors, as shown in Table 4. Consequently, the capital costs related to production and transmission are spread over a greater number of kWhs than is the case for lower load factor classes, resulting in lower costs per kWh and hence lower rates.

**TABLE 4**
**Comparative Load Factors**

| Rate Class | Energy Generated (MWh) (1) | Production A&E (MW) (2) | Load Factor (3) |
|---|---|---|---|
| Residential | 14,699,462 | 4,067 | 41% |
| Small GS | 3,978,667 | 968 | 47% |
| Large GS/Small Primary | 13,183,663 | 2,447 | 62% |
| Large Primary | 4,360,816 | 672 | 74% |
| Large Transmission | 4,157,133 | 484 | 98% |
| Total | 40,379,742 | 8,638 | 53% |

In addition, these customers take service at a higher voltage level. This means that they do not cause the costs associated with lower voltage distribution. Losses incurred in providing service also are lower. Table 5 lists voltage level and composite loss percentages for the various classes. Losses are 8.88% at the secondary level, 4.22% at the primary level and 1.47% at the transmission level.

**TABLE 5**
**Energy Loss Factors**

| Rate Class | Percent of Sale By Voltage Level: Secondary (1) | Percent of Sale By Voltage Level: Primary & Higher (2) | Composite Loss Percentage (3) |
|---|---|---|---|
| Residential | 100% | 0% | 8.88% |
| Small GS | 100% | 0% | 8.88% |
| Large GS/Small Primary | 68% | 32% | 7.52% |
| Large Primary | 0% | 100% | 4.22% |
| Large Transmission | 0% | 100% | 1.47% |

The per capita sales to these classes are also much greater than to the other classes, as shown in Table 6. AmerenUE sells almost 66,000,000 kWhs per Large Primary customer, but only about 13,000 kWhs per Residential customer, or 5,000 times more per capita, as shown in Table 6. The customer-related costs to serve

Large Primary customers are not 5,000 times the customer-related costs to serve the Residential customer.

**TABLE 6**
**Energy Sold Per Customer**

| Rate Class | Energy Sold (MWh) (1) | Number of Customers (2) | KWh Sold per Customer (3) |
|---|---|---|---|
| Residential | 13,500,608 | 1,027,667 | 13,137 |
| Small GS | 3,654,176 | 139,798 | 26,139 |
| Large GS/Small Primary | 12,262,006 | 10,414 | 1,177,407 |
| Large Primary | 4,184,241 | 64 | 65,721,066 |
| Large Transmission | 4,096,908 | 1 | 4,096,908,303 |
| Total | 37,697,940 | 1,177,945 | 32,003 |

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.

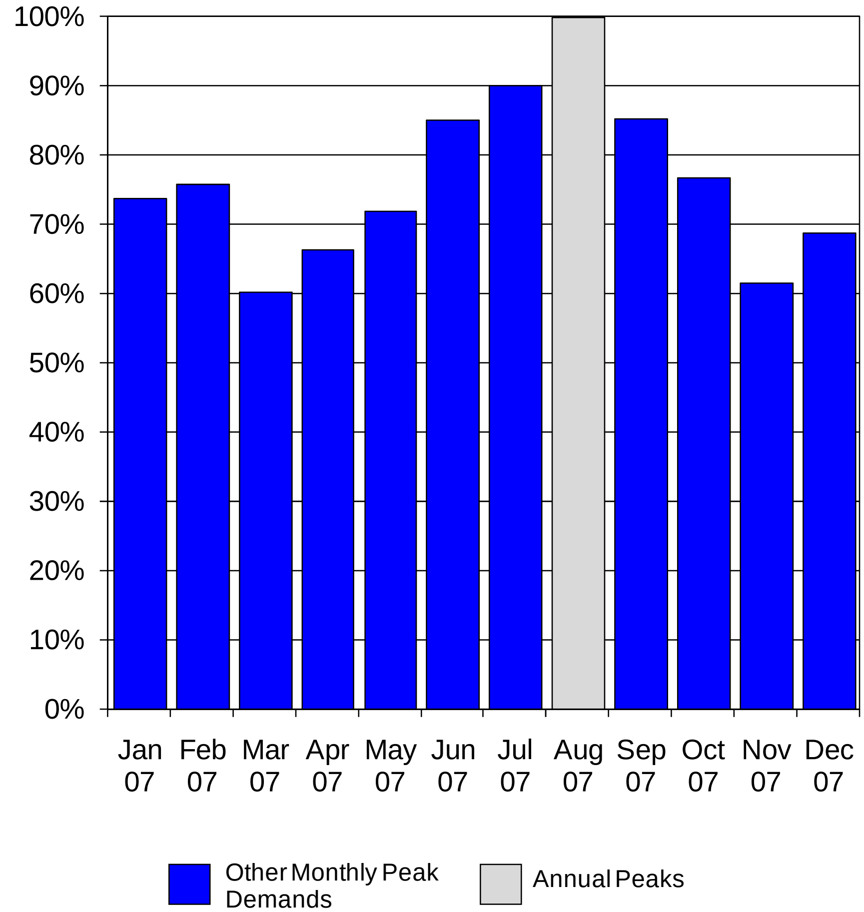
## Utility System Characteristics

**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. These characteristics for AmerenUE's Missouri jurisdiction are shown on Schedule MEB-COS-1. For convenience, it is also shown here as Figure 4.

## Figure 4
## AmerenUE

**Analysis of Ameren's (Missouri) Monthly Peak Demands**
**as a Percent of the Annual System Peak**
**For the Test Year Ended March 2008**




This shows the monthly system peak demands for the test year used in the study. The highlighted bar shows the month in which the highest peak occurred.

This analysis shows that summer peaks dominate the AmerenUE system. (This same information is presented in tabular form on Schedule MEB-COS-2.) This clearly shows that the system peak occurred in August, and was substantially higher than the monthly peaks occurring in the other months. Of the four months included in AmerenUE's allocation, June and September peaks are 15% lower than the annual peak, and the peak occurring in July is 10% lower than the annual peak. These lower loads simply are not representative of peak making weather and use of these lower demands as part of the allocation factor will distort the allocations and under-allocate costs to the most temperature sensitive loads.

**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 As discussed previously, 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 demands in all months may be important.

**Q WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE AMERENUE SYSTEM?**

A As noted, the AmerenUE load pattern has predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission cost. Demands in other months are of much less significance, do not compel the addition of generation capacity to serve them and should not be used in determining the allocation of costs.

**Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?**

A The two most predominantly used allocation methods in the industry are the coincident peak method and the A&E demand method.

The coincident method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of AmerenUE, this would be one or more peaks occurring during the summer.

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

A The A&E method is one of a family of methods which incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). 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 the energy if it were taken at the same demand rate each hour. The system “excess” demand is the difference between the system peak demand and the system average demand.

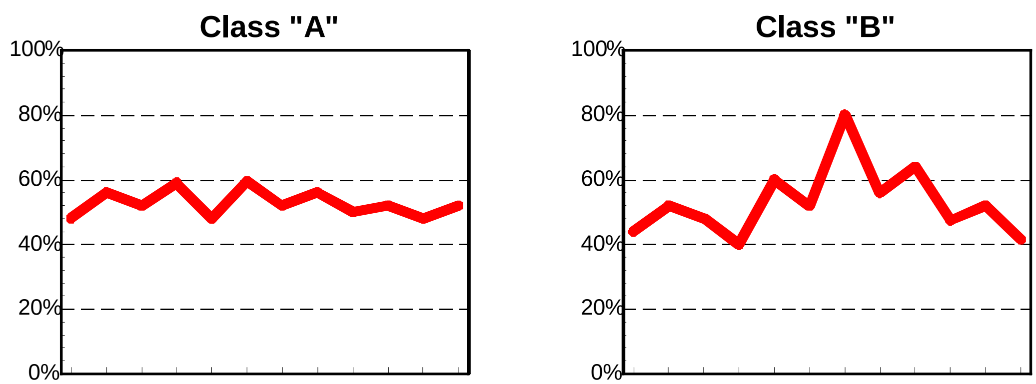
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.[1]

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

A As an example, Figure 5 shows two classes that have different monthly usage patterns.

**Figure 5**

**<u>Load Patterns</u>**




Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[2] than Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected

[1] <u>NARUC Electric Utility Cost Allocation Manual</u>, 1992, page 81.
[2] During any specified time period (e.g., month, year), the maximum demand of a class, regardless of when it occurs, is called the non-coincident peak demand.

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).

**Q WHAT DEMAND ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR GENERATION AND TRANSMISSION?**

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 peak summer months, or a version of an A&E cost of service study that uses class non-coincident peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I will make my recommendations based on the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

Schedule MEB-COS-3 shows the derivation of the demand allocation factor for generation using the annual class non-coincident peak.

**Q REFERRING TO SCHEDULE MEB-COS-3, PLEASE EXPLAIN THE DEVELOPMENT OF THE A&E ALLOCATION FACTOR.**

A Line 1 shows the annual non-coincident peak for each class occurring in the summer months. As explained previously, the summer months are selected because of their criticality in determining the need for generation capacity or firm purchased power. Line 2 shows the annual amount of energy required by each class. Line 3 is the average demand, in kilowatts, which is determined by dividing the annual energy in line 2 by the number of hours (8,760) in a year. Line 4 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown on line 5, is equal to the non-coincident peak demand shown on line 1 minus the average demand that is shown on line 3. Line 6 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

Finally, line 9 presents the composite A&E allocation factor. It is determined by weighting the average demand responsibility of each class (which is the same as each class' energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

**Q HOW DOES THIS DIFFER FROM THE ALLOCATOR AMERENUE HAS USED?**

A AmerenUE used a 4 NCP A&E allocation factor. This allocation factor differs from mine in two important respects. First, as is evident by the description of the factor, AmerenUE has used demands from four separate months, rather than the annual peak. Second, AmerenUE has not consistently utilized class peaks from even the four highest load months, but rather has included, for two classes, peaks that occur outside of the summer peak period. This is inappropriate and allocates too much cost to those classes that have one or more peaks occurring outside of the summer peak season.

**Q IN THE PREVIOUS AMERENUE RATE CASE (CASE NO. ER-2007-0002) YOU USED THREE SUMMER NON-COINCIDENT PEAKS. WHY ARE YOU USING ONLY THE ANNUAL SUMMER NCP IN THIS CASE?**

A In the last AmerenUE rate case, the period used for the cost of service allocation was the 12 months ended March 2006. During that particular 12-month period, the system peak occurred in July, and the maximum demands in June and August were both within about 4% of that annual peak, indicating that they, too, were representative of peak-making conditions. The load pattern in 2007, the period used for the cost of service study in this case, is different in that only one month (August 2007) exhibited the load level associated with true peak demands, and therefore only this month adequately captures the peak-making nature of the loads on the AmerenUE system. Use of other months as part of the allocation factor would dilute the impact the temperature sensitive classes have on the creation of system peaks, and would under-allocate costs to these temperature sensitive loads.

**Q ACCORDING TO YOUR SCHEDULE MEB-COS-2, THE SYSTEM PEAK WAS 8,638 MEGAWATTS FOR THIS YEAR. WHAT WAS THE CORRESPONDING ANNUAL PEAK FOR THE 12-MONTH PERIOD ENDED MARCH 2006 FROM THE LAST CASE?**

A It was 8,321 megawatts. Accordingly, the peak load during this year is consistent with the peak load during the prior rate case cost of service test year. It is the loads in the other months that have not exhibited the usual peak-making characteristic.

## <u>Making the Cost of Service Study – Summary</u>

**Q PLEASE SUMMARIZE THE PROCESS AND THE RESULTS OF A COST OF SERVICE ANALYSIS.**

A As previously discussed, 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 (customer, demand or energy) of that cost being incurred; and
3. Allocation – Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

**Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?**

A The results are presented in Schedule MEB-COS-4. In this cost of service study, which reflects costs at present rates, I have modified AmerenUE's inputs only to incorporate the additional margin from off-system sales recommended by Mr. Dauphinais, and to reflect income taxes at present rates.

**Q REFERRING TO SCHEDULE MEB-COS-4, PLEASE EXPLAIN THE ORGANIZATION AND WHAT IS SHOWN.**

A Schedule MEB-COS-4 is a summary of the key elements and the results of the class cost of service study. The top section of the schedule shows the main elements of rate base. This is followed by revenues, expenses, operating income and, on line 24, the rate of return earned on service to each customer class under present rates. Line 25 shows the index of return which is developed by dividing the rate of return of each class by the overall rate of return of 6.367% at present rates.

Line 26 shows the dollar difference between the revenues being produced by a class and the revenues required for the class to produce the average rate of return at present rates, and Line 27 shows the percentage change.

**Q OTHER THAN THE ALLOCATION OF THE GENERATION COSTS, HOW DOES YOUR STUDY DIFFER FROM THE ONE PRESENTED BY AMERENUE?**

A There are also differences in the allocation of the transmission system, the classification of non-fuel generation costs, and the allocation of off-system sales revenue.

**Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF TRANSMISSION COSTS?**

A AmerenUE has allocated transmission costs using the 12 monthly coincident peaks. The transmission system must be built to meet the system peak demand, which occurs in the summer; not the average of the 12 monthly peak demands, some of which are significantly lower (30% and more) than the summer peak demand. In this respect, the transmission system is similar to the generation system, and should be allocated in a similar fashion.

**Q WHAT IS THE ISSUE WITH RESPECT TO CERTAIN NON-FUEL GENERATION COSTS?**

A AmerenUE has designated a substantial proportion of its non-fuel operation and maintenance expenses as variable. In Data Request MIEC 5-04, AmerenUE was asked for the studies which it made to reach its conclusions supporting this particular separation of fixed and variable generation O&M expenses. AmerenUE responded by saying "There are no studies." It simply stated that it had been making the same division for a number of years.

Accordingly, AmerenUE has no support for the particular classification of non-fuel generation, operation and maintenance expenses that it has used in its study. It is more conventional to allocate these costs on an "expenses follows plant" basis, this is to say, on a demand basis. The vast majority of these costs do not vary in any appreciable way with the number of kWhs generated, but occur as a function of the existence of the plants, the hours of operation and the passage of time. My study incorporates this classification.

**Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF OFF-SYSTEM SALES?**

A AmerenUE has allocated the revenues from off-system sales on the basis of demand. The more traditional approach is to allocate the revenues from off-system sales to customer classes on the basis of class kWh requirements. This would make the allocation of the revenues consistent with the allocation of the underlying costs. (This method was just recently adopted in the KCP&L rate case, Case No. ER-2006-0314.)

**Q WHAT ARE THE RESULTS OF THIS COST OF SERVICE STUDY?**

A As shown on line 25 of Schedule MEB-COS-4, all classes of service are producing a rate of return above the average at present rates, except for the residential class. Line 27 shows the percentage change in current base revenues required to move each class from its current position to system average rate of return at present rates. The residential class would require an increase of 16.2%, and all other classes would require a decrease as shown on line 27.

**Q HAVE YOU PERFORMED ANY STUDIES IN WHICH A VARIATION OF THIS APPROACH TO THE ALLOCATION OF OFF-SYSTEM SALES WAS EMPLOYED?**

A Yes. Schedule MEB-COS-5 shows the results of allocating all costs and revenues the same way as the study which I described in Schedule MEB-COS-4, except that the revenue from off-system sales is allocated to customer classes using the production demand allocation factor, just as AmerenUE proposes. With this allocation, the disparities among classes narrow somewhat, but the results are basically the same.

**Q DO YOU HAVE CONCERNS ABOUT ANY OTHER ASPECTS OF AMERENUE'S CLASS COST OF SERVICE STUDY?**

A Yes. In reviewing the separation of the distribution accounts between customer-related and demand-related I noted that the customer-related component for these accounts, in AmerenUE's study, is significantly less than the customer-related component in studies recently filed by Kansas City Power & Light Company and Aquila. While I have not changed AmerenUE's customer/demand split for these accounts, I would note that AmerenUE's relatively low customer component has the effect of disadvantaging the customers on the Large Primary rate schedule.

Also, I believe that AmerenUE has allocated too much investment in the primary distribution network to the Large Primary customers as a result of not being more precise in recognizing the high voltage delivery of much of this load. I have not changed the study, but note that this, too, tends to understate the rate of return from these customers.

My colleague, David Stowe, addresses these issues in his testimony and shows the effect of appropriate modifications to AmerenUE's studies.

**Q HAVE YOU PROVIDED THE FULL PRINTOUT OF YOUR CLASS COST OF SERVICE STUDY?**

A Yes. I have included the full printout of the cost of service study on Schedule MEB-COS-4 as Attachment 1.

**Q DID YOU USE AMERENUE'S COST OF SERVICE MODEL TO PRODUCE YOUR CLASS COST OF SERVICE STUDY?**

A It was the starting point. The results of AmerenUE's allocation were replicated by utilizing the data contained in its cost of service model. Many of AmerenUE's allocation factors and functionalizations and classifications have been utilized, and the principal areas where I depart from AmerenUE have heretofore been explained in this testimony.

## 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 anything 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 mislead into using 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 (both energy efficiency and demand response programs) 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 determined using 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.

For example, assume that the relevant cost to produce and deliver energy is 8¢ per kWh. If a customer has an opportunity to install energy efficiency or DSM equipment that would allow the customer to reduce energy use or demand, the customer will be much more likely to make that investment if the price of electricity equals the cost of electricity, i.e., 8¢ per kWh, than if the customer is receiving a subsidized rate of 6¢ per kWh.

**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 (such as producing products at other locations where costs are lower), 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.

## Revenue Allocation

**Q PLEASE REFER AGAIN TO SCHEDULE MEB-COS-4 AND SUMMARIZE THE RESULTS OF YOUR CLASS COST OF SERVICE STUDY.**

A As indicated on line 27 of Schedule MEB-COS-4, movement of all classes to cost of service will require an increase to the residential class and a decrease to all other classes.

**Q HOW DOES AMERENUE PROPOSE TO ADJUST REVENUES?**

A AmerenUE proposes essentially an equal percentage across-the-board increase.

**Q WOULD AMERENUE'S ALLOCATION MOVE CLASS RATES CLOSER TO COST OF SERVICE?**

A No. AmerenUE's allocation would essentially maintain the status quo in which the residential class is below cost of service, and other classes are above cost of service.

**Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF AMERENUE'S REVENUE REQUIREMENT?**

A Yes. I will focus on adjustments to be made on a revenue neutral basis at present rates. After having made my recommended revenue neutral adjustments at present rates, any overall change in revenues allowed to AmerenUE can then be applied on an equal percentage across-the-board basis to these adjusted class revenues.

**Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.**

A My specific proposal is shown on Schedule MEB-COS-6. Column 1 shows class revenues at current rates, Column 2 shows my proposed adjustments on a revenue neutral basis and Column 3 shows the percentage change in revenues. My recommendation moves classes roughly 25% of the way toward cost of service. This 25% movement was selected because it makes a reasonable step in the right direction without imposing too disruptive of a revenue increase on the residential class. An overall increase of 4% on the residential class is a relatively modest step, but at least it is a step in the right direction.

While some will want to talk about the impact on the residential class of this increase, it is also important not to lose sight of the fact that by not moving all the way to cost of service, the other customer classes are continuing to bear more of the burden of the revenue responsibility than they should. My recommendation of moving 25% of the way toward cost of service, which limits the residential class increase to 4% (as compared to the 16% increase required to move all the way to cost of service) is relatively moderate, and must be considered in light of the fact that other classes are being asked to continue to provide part of the revenue responsibility that rightly should be shouldered by the residential class.

**Q DO YOU HAVE ANY CONCERNS WITH RESPECT TO THE DESIGN OF PROPOSED RATE 11 – THE LARGE PRIMARY SERVICE RATE?**

A The general structure of the rate is maintained, which is appropriate, but the proposed charges for all of the blocks are far too high. I would recommend that whatever decrease or increase is found appropriate for the Large Primary Service rate be applied as an equal percentage decrease or increase to all existing rate values.

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

A Yes, it does.

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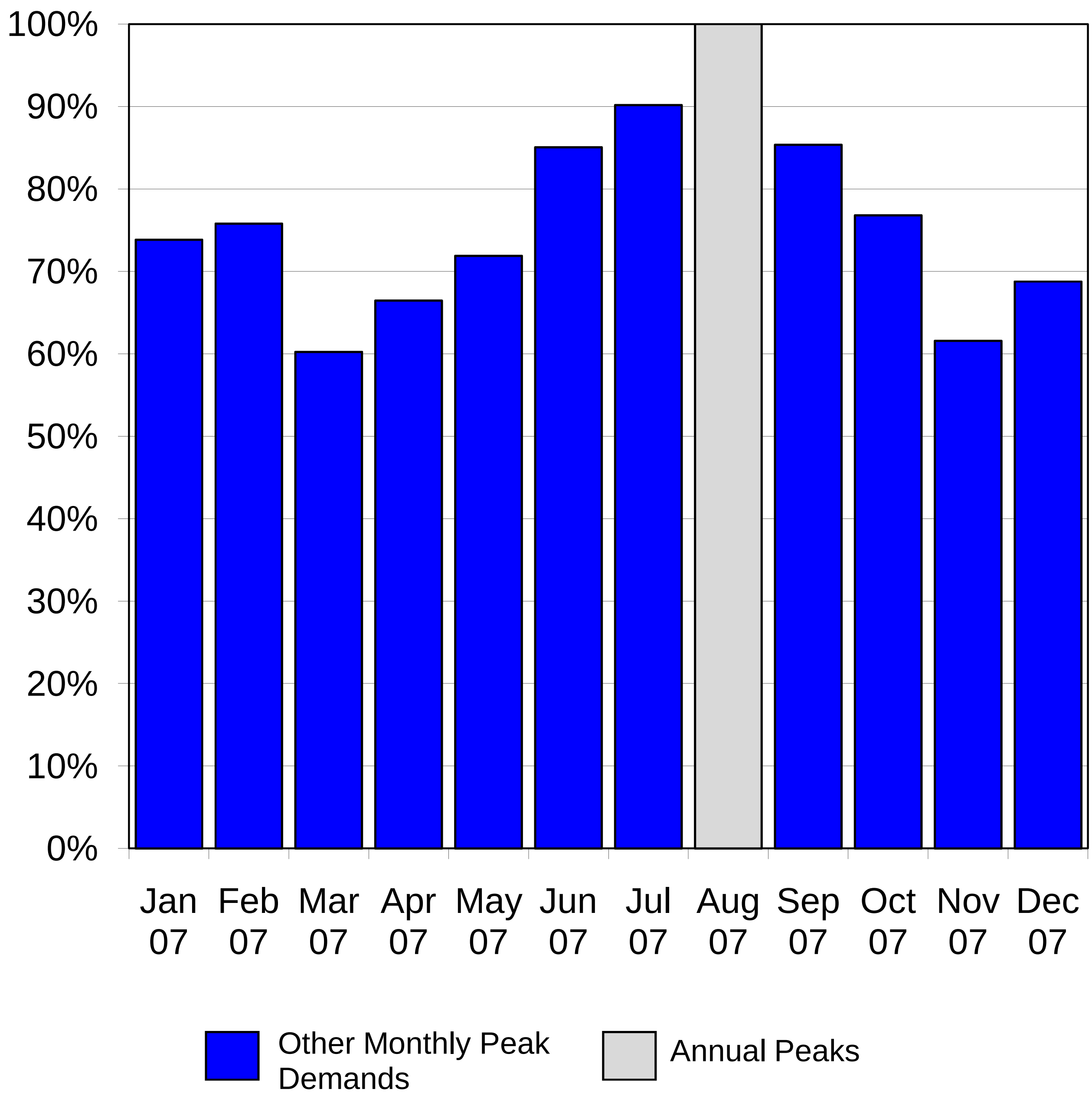
# AmerenUE

**Analysis of Ameren's (Missouri) Monthly Peak Demands**
**as a Percent of the Annual System Peak**
**<u>For the Test Year Ended March 2008</u>**



# AmerenUE

## Analysis of Ameren's Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) For the Test Year Ended March 2008

| Line | Description | Total Company MW (1) | Percent (2) |
|---|---|---|---|
| 1 | January 2007 | 6,379 | 73.8 |
| 2 | February | 6,548 | 75.8 |
| 3 | March | 5,204 | 60.2 |
| 4 | April | 5,741 | 66.5 |
| 5 | May | 6,211 | 71.9 |
| 6 | June | 7,347 | 85.1 |
| 7 | July | 7,790 | 90.2 |
| 8 | August | 8,638 | 100.0 |
| 9 | September | 7,373 | 85.4 |
| 10 | October | 6,635 | 76.8 |
| 11 | November | 5,318 | 61.6 |
| 12 | December | 5,941 | 68.8 |

Source: AmerenUE COS, System_Peak Worksheet

# AmerenUE

## Development of
## Average and Excess Demand Allocator
## Based on 1 NonCoincident Peaks
## For the Test Year Ended March 2008

| Line | Description | Missouri Retail (1) | Residential (2) | Small General Service (3) | Large General Service (4) | Large Primary Service (5) | Large Trans. Service (6) |
|---|---|---|---|---|---|---|---|
| 1 | Highest NCP (JJAS) - kW | 9,239,014 | 4,423,706 | 1,044,759 | 2,587,609 | 697,901 | 485,039 |
| 2 | Energy Sales with Losses - MWh | 40,379,742 | 14,699,462 | 3,978,667 | 13,183,663 | 4,360,816 | 4,157,133 |
| 3 | Average Demand - kW | 4,609,560 | 1,678,021 | 454,186 | 1,504,984 | 497,810 | 474,559 |
| 4 | Average Demand - Percent | 1.000000 | 0.364031 | 0.098531 | 0.326492 | 0.107995 | 0.102951 |
| 5 | Class Excess Demand - kW | 4,629,454 | 2,745,685 | 590,573 | 1,082,625 | 200,091 | 10,480 |
| 6 | Class Excess Demand - Percent | 1.000000 | 0.593090 | 0.127569 | 0.233856 | 0.043221 | 0.002264 |
| | Allocator: | | | | | | |
| 7 | Annual Load Factor * Average Demand | 0.533624 | 0.194256 | 0.052579 | 0.174224 | 0.057629 | 0.054937 |
| 8 | (1-LF) * Excess Demand | 0.466376 | 0.276603 | 0.059495 | 0.109065 | 0.020157 | 0.001056 |
| 9 | Average and Excess Demand Allocator | 1.000000 | 0.470859 | 0.112074 | 0.283289 | 0.077786 | 0.055993 |

Notes:

Line 3 equals Line 2 ÷ 8.760
Line 5 equals Line 1 - Line 3

System Annual Load Factor 53.36% (40,379,742 MWh ÷ 8,638.21 MW ÷ 8,760 hours)
1 - Load Factor 46.64%

# AMERENUE
## ELECTRIC COST OF SERVICE ALLOCATION STUDY
## FOR THE TEST YEAR ENDED MARCH 2008
## DOLLARS IN THOUSANDS

| LINE | DESCRIPTION | MISSOURI | RESIDENTIAL | SMALL GEN SERV | LARGE GEN SERV / SMALL PRIMARY | LARGE PRIMARY | LARGE TRANS |
|---|---|---|---|---|---|---|---|
| 1 | GROSS PLANT IN SERVICE | $12,131,480 | $6,270,304 | $1,416,348 | $ 3,188,036 | $796,503 | $460,290 |
| 2 | RESERVES FOR DEPRECIATION | $ 5,342,894 | $2,781,444 | $ 625,391 | $ 1,394,403 | $343,149 | $198,507 |
| 3 | NET PLANT IN SERVICE | $ 6,788,586 | $3,488,860 | $ 790,957 | $ 1,793,633 | $453,354 | $261,783 |
| | **RATE BASE ADDITIONS/REDUCTIONS:** | | | | | | |
| 4 | MATERIALS & SUPPLIES - FUEL | $ 284,601 | $ 103,603 | $ 28,042 | $ 92,920 | $ 30,736 | $ 29,300 |
| 5 | MATERIALS & SUPPLIES -LOCAL | $ 35,258 | $ 21,517 | $ 4,476 | $ 7,809 | $ 1,414 | $ 41 |
| 6 | CASH WORKING CAPITAL | $ 358 | $ 168 | $ 39 | $ 100 | $ 29 | $ 22 |
| 7 | CUSTOMER ADVANCES & DEPOSITS | $ (17,461) | $ (9,750) | $ (3,982) | $ (3,729) | $ - | $ - |
| 8 | ACCUMULATED DEFERRED INCOME TAXES | $(1,191,761) | $ (615,973) | $ (139,169) | $ (313,200) | $(78,205) | $(45,214) |
| 9 | TOTAL NET ORIGINAL COST RATE BASE | $ 5,899,581 | $2,988,425 | $ 680,362 | $ 1,577,533 | $407,328 | $245,933 |
| | **OPERATING REVENUES** | | | | | | |
| 10 | BASE REVENUE | $ 2,046,127 | $ 890,574 | $ 240,911 | $ 625,173 | $161,268 | $128,201 |
| 11 | OTHER REVENUE | $ 77,380 | $ 40,142 | $ 8,379 | $ 19,767 | $ 5,348 | $ 3,743 |
| 12 | LIGHTING REVENUE | $ 28,441 | $ 14,407 | $ 3,280 | $ 7,605 | $ 1,964 | $ 1,186 |
| 13 | SYSTEM REVENUE | $ 324,567 | $ 115,760 | $ 32,019 | $ 107,089 | $ 35,442 | $ 34,257 |
| 14 | TOTAL OPERATING REVENUE | $ 2,476,514 | $1,060,882 | $ 284,589 | $ 759,634 | $204,022 | $167,387 |
| | **OPERATING EXPENSES** | | | | | | |
| 15 | TOTAL PROD, T&D, CUST, AND A&G EXP | $ 1,529,164 | $ 716,205 | $ 164,850 | $ 427,454 | $125,351 | $ 95,304 |
| 16 | TOTAL DEPR AND AMMORT EXPENSES | $ 328,502 | $ 174,442 | $ 38,829 | $ 84,256 | $ 20,336 | $ 10,638 |
| 17 | REAL ESTATE AND PROPERTY TAXES | $ 98,511 | $ 50,916 | $ 11,504 | $ 25,889 | $ 6,464 | $ 3,737 |
| 18 | INCOME TAXES | $ 124,514 | $ 63,072 | $ 14,359 | $ 33,295 | $ 8,597 | $ 5,191 |
| 19 | PAYROLL TAXES | $ 20,218 | $ 10,459 | $ 2,266 | $ 5,263 | $ 1,451 | $ 778 |
| 20 | FEDERAL EXCISE TAX | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | REVENUE TAXES | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | TOTAL OPERATING EXPENSES | $ 2,100,909 | $1,015,095 | $ 231,809 | $ 576,157 | $162,199 | $115,648 |
| 23 | NET OPERATING INCOME | $ 375,605 | $ 45,787 | $ 52,780 | $ 183,477 | $ 41,822 | $ 51,739 |
| 24 | RATE OF RETURN | 6.367% | 1.532% | 7.758% | 11.631% | 10.268% | 21.038% |
| 25 | RATE OF RETURN INDEX | 100 | 24 | 122 | 183 | 161 | 330 |
| 26 | REVENUE CHANGE TO EQUAL COS | 0 | 144,475 | -9,464 | -83,041 | -15,889 | -36,081 |
| 27 | PERCENT OF BASE REVENUE | 0.0% | 16.2% | -3.9% | -13.3% | -9.9% | -28.1% |

## AMERENUE
### ELECTRIC COST OF SERVICE ALLOCATION STUDY
### FOR THE TEST YEAR ENDED MARCH 2008
### DOLLARS IN THOUSANDS *

| LINE | DESCRIPTION | MISSOURI | RESIDENTIAL | SMALL GEN SERV | LARGE GEN SERV / SMALL PRIMARY | LARGE PRIMARY | LARGE TRANS |
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| | **RATE BASE ADDITIONS/REDUCTIONS:** | | | | | | |
| 4 | MATERIALS & SUPPLIES - FUEL | $ 284,601 | $ 103,603 | $ 28,042 | $ 92,920 | $ 30,736 | $ 29,300 |
| 5 | MATERIALS & SUPPLIES -LOCAL | $ 35,258 | $ 21,517 | $ 4,476 | $ 7,809 | $ 1,414 | $ 41 |
| 6 | CASH WORKING CAPITAL | $ 358 | $ 168 | $ 39 | $ 100 | $ 29 | $ 22 |
| 7 | CUSTOMER ADVANCES & DEPOSITS | $ (17,461) | $ (9,750) | $ (3,982) | $ (3,729) | $ - | $ - |
| 8 | ACCUMULATED DEFERRED INCOME TAXES | $(1,191,761) | $ (615,973) | $ (139,169) | $ (313,200) | $(78,205) | $(45,214) |
| 9 | TOTAL NET ORIGINAL COST RATE BASE | $ 5,899,581 | $2,988,425 | $ 680,362 | $ 1,577,533 | $407,328 | $245,933 |
| | **OPERATING REVENUES** | | | | | | |
| 10 | BASE REVENUE | $ 2,046,127 | $ 890,574 | $ 240,911 | $ 625,173 | $161,268 | $128,201 |
| 11 | OTHER REVENUE | $ 77,380 | $ 40,142 | $ 8,379 | $ 19,767 | $ 5,348 | $ 3,743 |
| 12 | LIGHTING REVENUE | $ 28,441 | $ 14,407 | $ 3,280 | $ 7,605 | $ 1,964 | $ 1,186 |
| 13 | SYSTEM REVENUE | $ 324,567 | $ 150,476 | $ 36,420 | $ 93,049 | $ 25,625 | $ 18,997 |
| 14 | TOTAL OPERATING REVENUE | $ 2,476,514 | $1,095,599 | $ 288,990 | $ 745,594 | $194,204 | $152,127 |
| | **OPERATING EXPENSES** | | | | | | |
| 15 | TOTAL PROD, T&D, CUST, AND A&G EXP | $ 1,529,164 | $ 716,205 | $ 164,850 | $ 427,454 | $125,351 | $ 95,304 |
| 16 | TOTAL DEPR AND AMMORT EXPENSES | $ 328,502 | $ 174,442 | $ 38,829 | $ 84,256 | $ 20,336 | $ 10,638 |
| 17 | REAL ESTATE AND PROPERTY TAXES | $ 98,511 | $ 50,916 | $ 11,504 | $ 25,889 | $ 6,464 | $ 3,737 |
| 18 | INCOME TAXES | $ 124,514 | $ 63,072 | $ 14,359 | $ 33,295 | $ 8,597 | $ 5,191 |
| 19 | PAYROLL TAXES | $ 20,218 | $ 10,459 | $ 2,266 | $ 5,263 | $ 1,451 | $ 778 |
| 20 | FEDERAL EXCISE TAX | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | REVENUE TAXES | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | TOTAL OPERATING EXPENSES | $ 2,100,909 | $1,015,095 | $ 231,809 | $ 576,157 | $162,199 | $115,648 |
| 23 | NET OPERATING INCOME | $ 375,605 | $ 80,504 | $ 57,181 | $ 169,437 | $ 32,005 | $ 36,479 |
| 24 | RATE OF RETURN | 6.367% | 2.694% | 8.404% | 10.741% | 7.857% | 14.833% |
| 25 | RATE OF RETURN INDEX | 100 | 42 | 132 | 169 | 123 | 233 |
| 26 | REVENUE CHANGE TO EQUAL COS | 0 | 109,759 | -13,865 | -69,001 | -6,072 | -20,821 |
| 27 | PERCENT OF BASE REVENUE | 0.0% | 12.3% | -5.8% | -11.0% | -3.8% | -16.2% |

* Off-system sales margin allocated on the generation demand allocation factor.

# AmerenUE

**Recommended Revenue Neutral Class**
**Revenue Adjustments at Present Rates**
**($/Thousands)**

| Line | Rate Class | Current Revenues (1) | Adjustment Amount (2) | Adjustment Percent (3) |
|---|---|---|---|---|
| 1 | Residential | $ 890,574 | $ 35,620 | 4.0% |
| 2 | Small GS | 240,911 | (2,333) | (1.0) |
| 3 | Large GS/Primary | 625,173 | (20,474) | (3.3) |
| 4 | Large Primary | 161,268 | (3,917) | (2.4) |
| 5 | Large Transmission | 128,201 | (8,896) | (6.9) |
| | | $ 2,046,127 | - 0 - | - 0 - |

# ATTACHMENT 1

NON-
PROPRIETARY
VERSION