

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.

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

MIEC Exhibit No. 615 NP
Case No(s) ER-2008-0318
Date 12-04-08 Rptr KE

**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)
)
COUNTY OF ST. LOUIS)

SS


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.

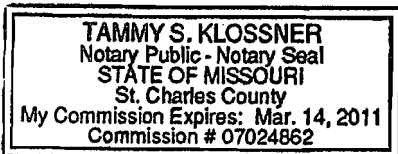
2. Attached hereto and made a part hereof for all purposes is my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2008-0318.


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.



Maurice Brubaker

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





Notary Public

**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

Direct Testimony of Maurice Brubaker

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

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

4 **Q WHAT IS YOUR OCCUPATION?**

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

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

8 A This information is included in Appendix A to my direct testimony on revenue
9 requirement issues.

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

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

**Maurice Brubaker
Page 1**

1 Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

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

5 Q HOW IS YOUR TESTIMONY ORGANIZED?

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

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

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

SUMMARY

1

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

3 **A My testimony and recommendations may be summarized as follows:**

- 4 1. Class cost of service is the most important guideline for establishing the level of
5 rates charged to customers.
- 6 2. AmerenUE exhibits significant summer peak demands.
- 7 3. There are two generally accepted methods for allocating generation and
8 transmission fixed costs that would apply to AmerenUE. These are the
9 coincident peak methodology and the average and excess (A&E) methodology.
- 10 4. For AmerenUE's generation and transmission system, I recommend using an
11 A&E demand methodology. Specifically, an annual non-coincident peak A&E
12 method which uses class peak demands from the summer peak month and class
13 annual energy consumption. The single annual non-coincident peak (NCP) is
14 appropriate for this test year and necessary to capture the peak which drives
15 capacity additions.
- 16 5. The A&E methodology appropriately considers both class maximum demands
17 and class load factor, as well as diversity between class peaks and the system
18 peak.
- 19 6. AmerenUE's cost of service study contains several deficiencies including:
20 (1) use of a Four Non-Coincident Peak Average and Excess (4 NCP A&E)
21 allocation method; (2) allocation of transmission costs using 12 monthly
22 coincident peaks; (3) allocation of a significant proportion of non-fuel production
23 expenses on energy; and (4) an inappropriate allocation of off-system sales.
- 24 7. More reasonable cost of service studies, which I present and summarize on
25 Schedules MEB-COS-4 and MEB-COS-5, show how class revenues compare to
26 cost of service.
- 27 8. A modest realignment of class revenues to move them closer to costs should be
28 implemented, as presented on Schedule MEB-COS-6.
- 29 9. Any decrease or increase found appropriate for Rate 11 (Large Primary Service)
30 should be applied as a uniform percentage decrease or increase to the existing
31 charges in the tariff.

Maurice Brubaker
Page 3

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 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,

1 schools, businesses, factories – because this is where the lights, appliances,
2 machines, air conditioning, etc. are located. Thus, every utility must provide a path
3 through which electricity can be delivered regardless of the customer's **demand** and
4 **energy** requirements at any point in time.

5 Even at the same location, electricity may be used in a variety of applications.
6 Homeowners, for example, use electricity for lighting, space conditioning, and to
7 operate various appliances. At any instant, several appliances may be operating
8 (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and
9 when reflects the second dimension of utility service – the rate of electricity use or
10 **demand**. The demand imposed by customers is an especially important
11 characteristic because the maximum demands determine how much capacity the
12 utility is obligated to provide.

13 Generating units, transmission lines and substations and distribution lines and
14 substations are rated according to the maximum demand that can safely be imposed
15 on them. (They are not rated according to average annual demand; that is, the
16 amount of energy consumed during the year divided by 8,760 hours.) On a hot
17 summer afternoon when customers demand 9,000 megawatts (MW) of electricity, the
18 utility must have at least 9,000 MW of generation, plus additional capacity to provide
19 adequate reserves, so that when a consumer flips the switch, the lights turn on, the
20 machines operate and air conditioning systems cool our homes, schools, offices, and
21 factories.

22 Satisfying customers' demand for electricity over time – providing **energy** – is
23 the third dimension of utility service. It is also the dimension with which many people
24 are most familiar, because people often think of electricity simply in terms of kWhs.

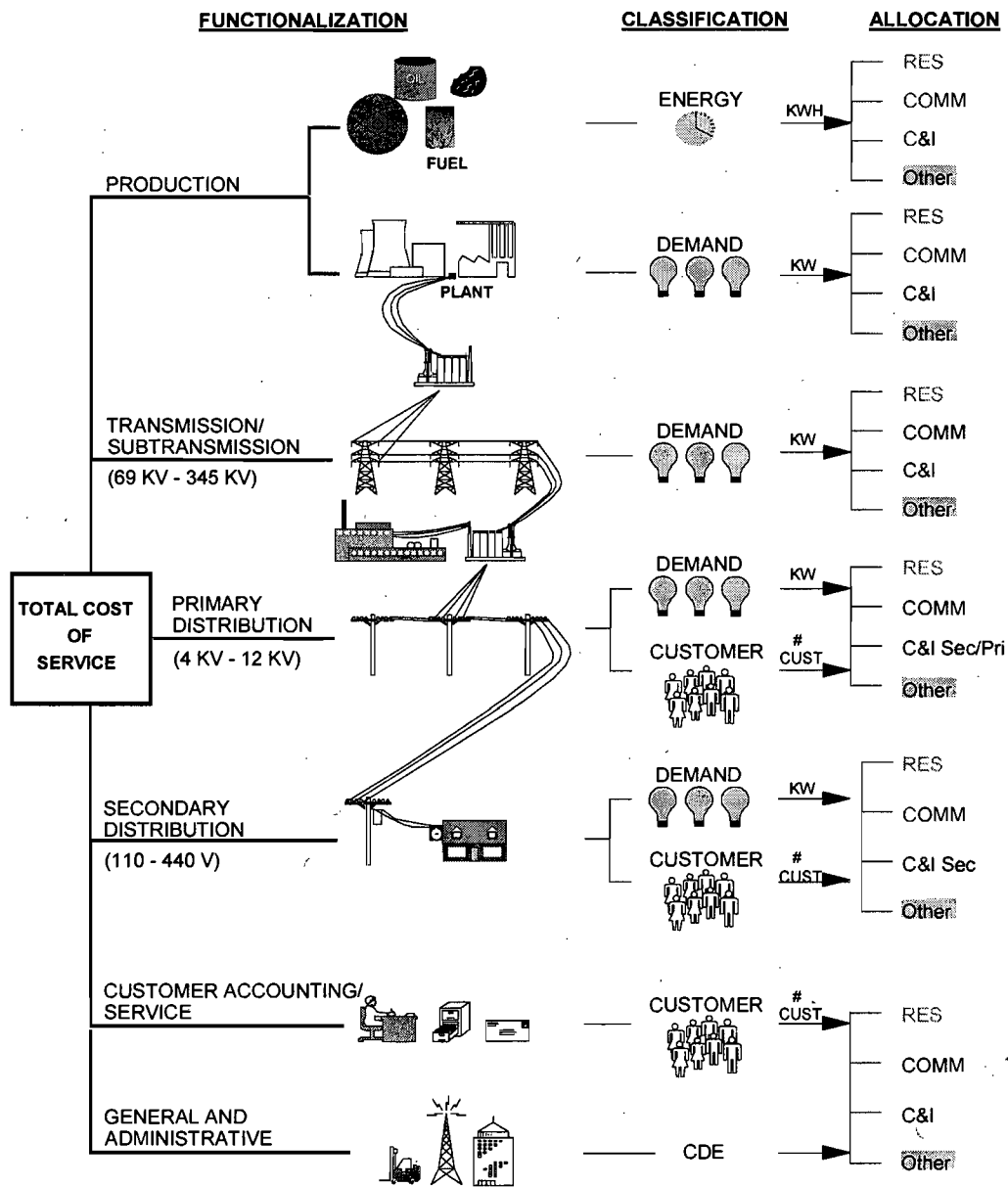
1 To see one reason why this isn't so, consider a more familiar commodity – tomatoes,
2 for example.

3 The tomatoes we buy at the supermarket for about \$2.00 a pound might
4 originally come from Florida where they are bought for about 30¢ a pound. In
5 addition to the cost of buying them at the point of production, there is the cost of
6 bringing them to the state of Missouri and distributing them in bulk to local
7 wholesalers. The cost of transportation, insurance, handling and warehousing must
8 be added to the original 30¢ a pound. Then they are distributed to neighborhood
9 stores, which adds more handling costs as well as the store's own costs of light, heat,
10 personnel and rent. Shoppers can then purchase as many or few tomatoes as they
11 desire at their convenience. In addition, there are losses from spoilage and damage
12 in handling. These "line losses" represent an additional cost which must be
13 recovered in the final price. What we are really paying for at the store is not only the
14 vegetable itself, but the service of having it available in convenient amounts and
15 locations. If we took the time and trouble (and expense) to go down to the wholesale
16 produce distributor, the price would be less. If we could arrange to buy them in bulk
17 in Florida, they would be even cheaper.

18 As illustrated in Figure 1, electric utilities are similar, except that in most cases
19 (including Missouri), a single company handles everything from production on down
20 through wholesale (bulk and area transmission) and retail (distribution to homes and
21 stores). The crucial difference is that, unlike producers and distributors of tomatoes,
22 electric utilities have an obligation to provide continuous reliable service. The
23 obligation is assumed in return for the exclusive right to serve all customers located
24 within its territorial franchise. In addition to satisfying the energy (or kWh)
25 requirements of its customers, the obligation to serve means that the utility must also

- 1 provide the necessary facilities to attach customers to the grid (so that service can be
- 2 used at the point where it is to be consumed) and these facilities must be responsive
- 3 to changes in the kilowatt demands whenever they occur.

Figure 1
PRODUCTION AND DELIVERY OF ELECTRICITY



1 **A CLOSER LOOK AT THE COST OF SERVICE STUDY**

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

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

11 **Functionalization**

12 **Q PLEASE EXPLAIN FUNCTIONALIZATION.**

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

17 Referring to Figure 1, at the top level there is generation. The next level is the
18 extra high voltage transmission and subtransmission system (34,500 to 345,000
19 volts). Then the voltage is stepped down to primary voltage levels of distribution –
20 4,160 to 12,000 volts. Finally, the voltage is stepped down by pole transformers at
21 the "secondary" level to 110/220 volts used to serve homes, barbershops and the
22 like. Additional investment and expenses are required to serve customers at
23 secondary voltages, compared to the cost of serving customers at higher voltage.

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

10 Classification

11 **Q WHAT IS CLASSIFICATION?**

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

15 Looking at the production function, the amount of production plant capacity
16 required is primarily determined by the peak rate of usage during the year. If the
17 utility anticipates a peak demand of 9,000 megawatts – it must install and/or contract
18 for enough generating capacity to meet that anticipated demand (plus some reserve
19 to compensate for variations in load and capacity that is temporarily unavailable).

20 There will be many hours during the day or during the year when not all of this
21 generating capacity will be needed. Nevertheless, it must be in place to meet the
22 peak demands on the system. Thus, production plant investment is usually classified
23 to demand. **Regardless of how production plant investment is classified, the**
24 **associated capital costs** (which include return on investment, depreciation, fixed

1 operation and maintenance expenses, taxes and insurance) **are fixed**; that is, **they**
2 **do not vary with the amount of kWhs generated and sold.** These fixed costs are
3 determined by the amount of capacity (i.e., kilowatts) which the utility must install to
4 satisfy its obligation-to-serve requirement.

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

9 Most other O&M expenses are fixed and therefore are classified as
10 demand-related. Variable O&M expenses are classified as energy-related.
11 Demand-related and energy-related types of operating costs are not impacted by the
12 number of customers served.

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

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

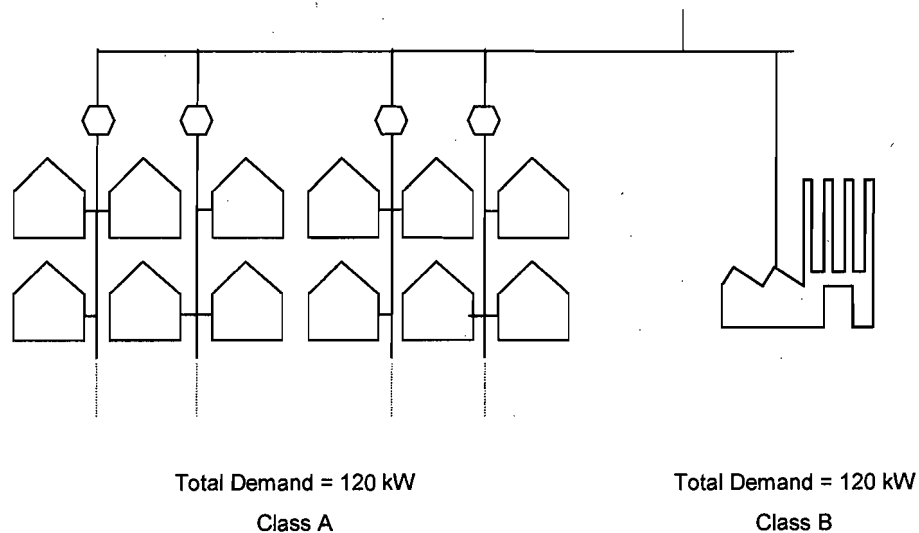
24 Figure 2, as an example, shows the distribution network for a utility with two
25 customer classes, A and B. The physical distribution network necessary to attach

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

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

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

Figure 2
Classification of Distribution Investment



1 **Demand vs. Energy Costs**

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

4 **A** The difference between demand-related and energy-related costs explains the fallacy
5 of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3,
6 compares the electrical requirements of two customers, A and B, each using 100-watt
7 light bulbs.

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

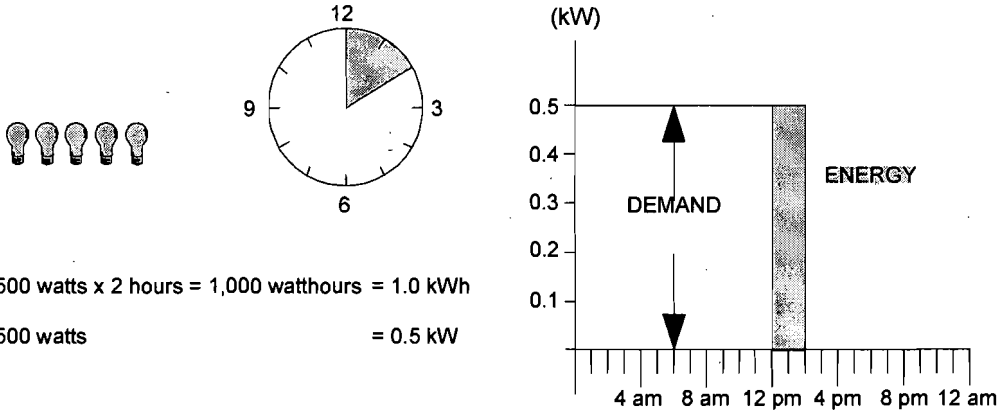
13 Although both customers had precisely the same kWh energy usage,
14 Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must
15 install 2.5 times as much generating capacity for Customer A as for Customer B. The
16 cost of serving Customer A, therefore, is much higher.

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

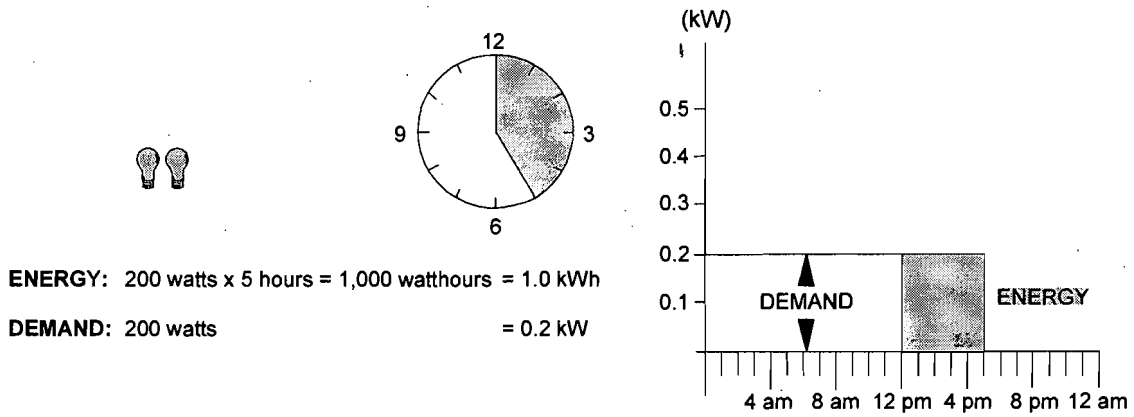
18 **A** Yes. Load factor is an expression of how uniformly a customer uses energy. In our
19 example of the light bulbs, the load factor of Customer B would be higher than the
20 load factor of Customer A because the use of electricity was spread over a longer
21 period of time, and the number of kWhs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

Figure 3 DEMAND VS. ENERGY

CUSTOMER A



CUSTOMER B



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

4 Consider also the analogy of a rental car which costs \$40/day and 20¢/mile. If
5 Customer A drives only 20 miles a day, the average cost will be \$2.20/mile. But for
6 Customer B, who drives 200 miles a day, spreading the daily rental charge over the
7 total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost
8 rate (daily charge) and variable cost rate (mileage charge) are identical, but the
9 average total cost per mile will differ depending on how intensively the car is used.
10 Likewise, the average cost per kWh will depend on how intensively the generating
11 plant is used. A low load factor indicates that the capacity is idle much of the time; a
12 high load factor indicates a more steady rate of usage. Since industrial customers
13 generally have higher load factors than residential or commercial customers, they are
14 less costly to serve on a per-kWh basis. Again, we can say that "a kilowatthour is a
15 kilowatthour" as to energy content, but there may be a big difference in how much
16 generating plant investment is required to convert the raw fuel into electric energy.

17 Allocation

18 **Q WHAT IS ALLOCATION?**

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

23 For example, we have already determined that the amount of fuel expense on
24 the system is a function of the energy required by customers. In order to allocate this

1 expense among classes, we must determine how much each class contributes to the
 2 total kWh consumption and we must recognize the line losses associated with
 3 transporting and distributing the kWh. These contributions, expressed in percentage
 4 terms, are then multiplied by the expense to determine how much expense should be
 5 attributed to each class. The energy allocators for AmerenUE's retail customers are
 6 shown in Table 1.

TABLE 1
Energy Allocation Factor

<u>Rate Class</u>	<u>Energy Generated (MWh)</u> (1)	<u>Allocation Factor</u> (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	<u>4,157,133</u>	<u>10.30%</u>
Total	40,379,742	100.00%

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

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

14 **A** Yes. Recall that load factor is a measure of the consistency or uniformity of use of
 15 demand. Accordingly, customer classes' whose energy allocation factor is a larger

1 percentage than their demand allocation have an above-average load factor, while
2 customers whose demand allocation factor is higher than their energy allocation
3 factor have a below-average load factor.

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

<u>Rate Class</u>	<u>Production A&E (MW) (1)</u>	<u>Allocation Factor (2)</u>
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	<u>484</u>	<u>5.60%</u>
Total	8,638	100.00%

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

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

<u>Rate Class</u>	<u>Cost-Based Revenue</u> (1)	<u>Energy Sales (MWh)</u> (2)	<u>Cost per kWh</u> (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	<u>92,120</u>	<u>4,096,908</u>	<u>2.25</u>
Total	\$2,046,127	37,697,940	5.43¢

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

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

TABLE 4
Comparative Load Factors

<u>Rate Class</u>	<u>Energy Generated (MWh)</u> (1)	<u>Production A&E (MW)</u> (2)	<u>Load Factor</u> (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	<u>4,157,133</u>	<u>484</u>	<u>98%</u>
Total	40,379,742	8,638	53%

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

TABLE 5
Energy Loss Factors

<u>Rate Class</u>	<u>Percent of Sale By Voltage Level</u>		<u>Composite Loss Percentage</u> (3)
	<u>Secondary</u> (1)	<u>Primary & Higher</u> (2)	
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%

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

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

<u>Rate Class</u>	<u>Energy Sold (MWh)</u> (1)	<u>Number of Customers</u> (2)	<u>KWh Sold per Customer</u> (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	<u>4,096,908</u>	<u>1</u>	<u>4,096,908,303</u>
Total	37,697,940	1,177,945	32,003

3 These differences in the service and usage characteristics – load factor,
4 delivery voltage and size – result in a lower per unit cost to serve customers operating
5 at a higher load factor, taking service at higher delivery voltage and purchasing a
6 larger quantity of power and energy at a single delivery point.

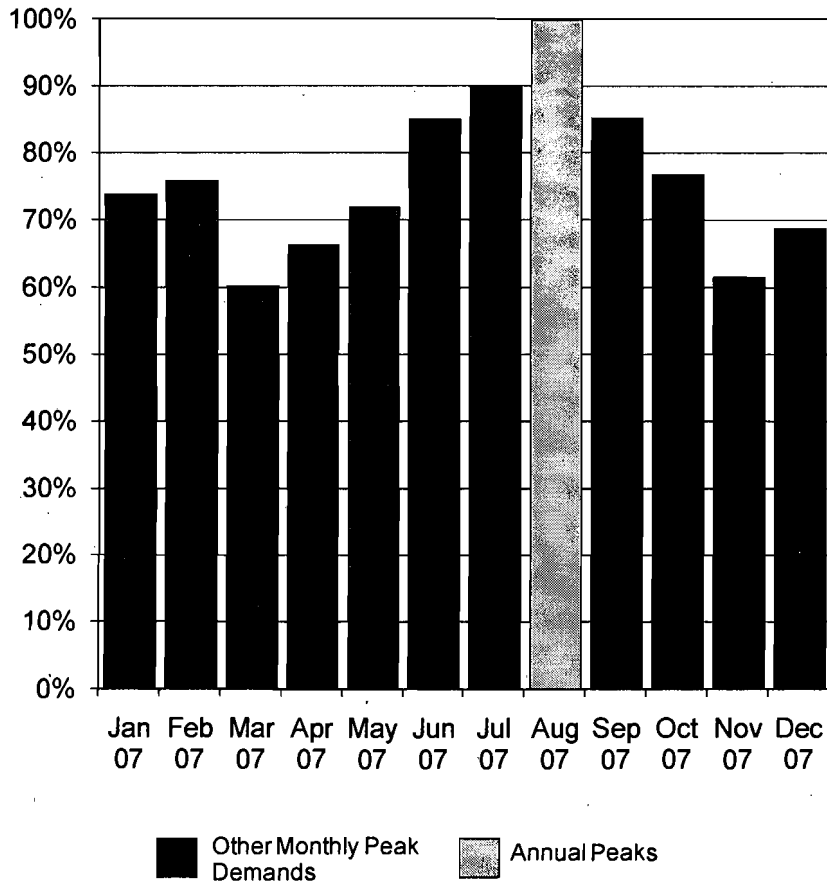
7 **Utility System Characteristics**

8 **Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?**

9 A Utility system load characteristics are an important factor in determining the specific
10 method which should be employed to allocate fixed, or demand-related costs on a
11 utility system. The most important characteristic is the annual load pattern of the
12 utility. These characteristics for AmerenUE's Missouri jurisdiction are shown on
13 Schedule MEB-COS-1. For convenience, it is also shown here as Figure 4.

Figure 4 AmerenUE

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



1 This shows the monthly system peak demands for the test year used in the study.

2 The highlighted bar shows the month in which the highest peak occurred.

3 This analysis shows that summer peaks dominate the AmerenUE system.

4 (This same information is presented in tabular form on Schedule MEB-COS-2.) This

5 clearly shows that the system peak occurred in August, and was substantially higher

6 than the monthly peaks occurring in the other months. Of the four months included in

7 AmerenUE's allocation, June and September peaks are 15% lower than the annual

Maurice Brubaker
Page 20

1 peak, and the peak occurring in July is 10% lower than the annual peak. These lower
2 loads simply are not representative of peak making weather and use of these lower
3 demands as part of the allocation factor will distort the allocations and under-allocate
4 costs to the most temperature sensitive loads.

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

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

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

13 A As discussed previously, production and transmission plant must be sized to meet the
14 maximum demand imposed on these facilities. Thus, an appropriate allocation
15 method should accurately reflect the characteristics of the loads served by the utility.
16 For example, if a utility has a high summer peak relative to the demands in other
17 seasons, then production and transmission capacity costs should be allocated
18 relative to each customer class' contribution to the summer peak demands. If a utility
19 has predominant peaks in both the summer and winter periods, then an appropriate
20 allocation method would be based on the demands imposed during both the summer
21 and winter peak periods. For a utility with a very high load factor and/or a
22 non-seasonal load pattern, then demands in all months may be important.

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

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

8 Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?

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

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

14 Q WHAT IS THE A&E METHOD?

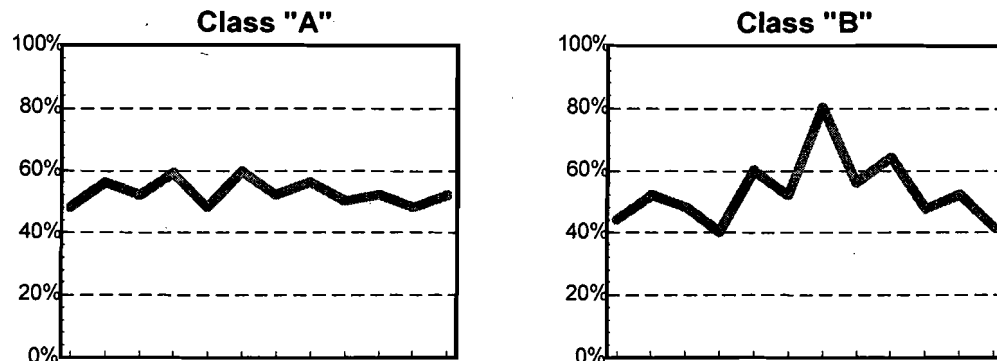
15 A The A&E method is one of a family of methods which incorporates a consideration of
16 both the maximum rate of use (demand) and the duration of use (energy). As the
17 name implies, A&E makes a conceptual split of the system into an "average"
18 component and an "excess" component. The "average" demand is simply the total
19 kWh usage divided by the total number of hours in the year. This is the amount of
20 capacity that would be required to produce the energy if it were taken at the same
21 demand rate each hour. The system "excess" demand is the difference between the
22 system peak demand and the system average demand.

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

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

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

Figure 5
Load Patterns



9 Both classes use the same total amount of energy and, therefore, have the same
10 average demand. Class B, though, has a much greater maximum demand² than
11 Class A. The greater maximum demand imposes greater costs on the utility system.
12 This is because the utility must provide sufficient capacity to meet the projected

¹NARUC Electric Utility Cost Allocation Manual, 1992, page 81.

²During 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.

1 maximum demands of its customers. There may also be higher costs due to the
2 greater variability of usage of some classes. This variability requires that a utility
3 cycle its generating units in order to match output with demand on a real time basis.
4 The stress of cycling generating units up and down causes wear and tear on the
5 equipment, resulting in higher maintenance cost.

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

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

12 **A** First, in order to reflect cost causation the methodology must give predominant weight
13 to loads occurring during the summer months. Loads during these months (the peak
14 loads) are the primary driver which has and continues to cause the utility to expand
15 its generation and transmission capacity, and therefore should be given predominant
16 weight in the allocation of capacity costs.

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

Maurice Brubaker
Page 24

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

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

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

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

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

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

21 A AmerenUE used a 4 NCP A&E allocation factor. This allocation factor differs from
22 mine in two important respects. First, as is evident by the description of the factor,
23 AmerenUE has used demands from four separate months, rather than the annual

1 peak. Second, AmerenUE has not consistently utilized class peaks from even the
2 four highest load months, but rather has included, for two classes, peaks that occur
3 outside of the summer peak period. This is inappropriate and allocates too much cost
4 to those classes that have one or more peaks occurring outside of the summer peak
5 season.

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

9 A In the last AmerenUE rate case, the period used for the cost of service allocation was
10 the 12 months ended March 2006. During that particular 12-month period, the
11 system peak occurred in July, and the maximum demands in June and August were
12 both within about 4% of that annual peak, indicating that they, too, were
13 representative of peak-making conditions. The load pattern in 2007, the period used
14 for the cost of service study in this case, is different in that only one month (August
15 2007) exhibited the load level associated with true peak demands, and therefore only
16 this month adequately captures the peak-making nature of the loads on the
17 AmerenUE system. Use of other months as part of the allocation factor would dilute
18 the impact the temperature sensitive classes have on the creation of system peaks,
19 and would under-allocate costs to these temperature sensitive loads.

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

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

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

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

11 A As previously discussed, the cost of service procedure involves three steps:
12 1. Functionalization – Identify the different functional "levels" of the system;
13 2. Classification – Determine, for each functional type, the primary cause or causes
14 (customer, demand or energy) of that cost being incurred; and
15 3. Allocation – Calculate the class proportional responsibilities for each type of cost
16 and spread the cost among classes.

17 Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

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

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

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

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

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

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

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

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

1 respect, the transmission system is similar to the generation system, and should be
2 allocated in a similar fashion.

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

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

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

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

20 A AmerenUE has allocated the revenues from off-system sales on the basis of demand.
21 The more traditional approach is to allocate the revenues from off-system sales to
22 customer classes on the basis of class kWh requirements. This would make the

1 allocation of the revenues consistent with the allocation of the underlying costs. (This
2 method was just recently adopted in the KCP&L rate case, Case No. ER-2006-0314.)

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

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

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

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

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

20 A Yes. In reviewing the separation of the distribution accounts between
21 customer-related and demand-related I noted that the customer-related component
22 for these accounts, in AmerenUE's study, is significantly less than the

1 customer-related component in studies recently filed by Kansas City Power & Light
2 Company and Aquila. While I have not changed AmerenUE's customer/demand split
3 for these accounts, I would note that AmerenUE's relatively low customer component
4 has the effect of disadvantaging the customers on the Large Primary rate schedule.

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

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

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

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

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

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

1 **Adjustment of Class Revenues**

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

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

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

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

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

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

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

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

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

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

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

9 A Yes. The success of DSM (both energy efficiency and demand response programs)
10 depends, to a large extent, on customer receptivity. There are many actions that can
11 be taken by consumers to reduce their electricity requirements. A major element in a
12 customer's decision-making process is the amount of reduction that can be achieved
13 in the electric bill as a result of DSM activities. If the bill received by a customer is
14 subsidized by other customers; that is, the bill is determined using rates which are
15 below cost, that customer will have less reason to engage in DSM activities than
16 when the bill reflects the actual cost of the electric service provided.

17 For example, assume that the relevant cost to produce and deliver energy is
18 8¢ per kWh. If a customer has an opportunity to install energy efficiency or DSM
19 equipment that would allow the customer to reduce energy use or demand, the
20 customer will be much more likely to make that investment if the price of electricity
21 equals the cost of electricity, i.e., 8¢ per kWh, than if the customer is receiving a
22 subsidized rate of 6¢ per kWh.

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

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

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

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

1 **Revenue Allocation**

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

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

7 Q HOW DOES AMERENUE PROPOSE TO ADJUST REVENUES?

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

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

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

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

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

19 Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.

20 A My specific proposal is shown on Schedule MEB-COS-6. Column 1 shows class
21 revenues at current rates, Column 2 shows my proposed adjustments on a revenue

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

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

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

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

Maurice Brubaker
Page 36

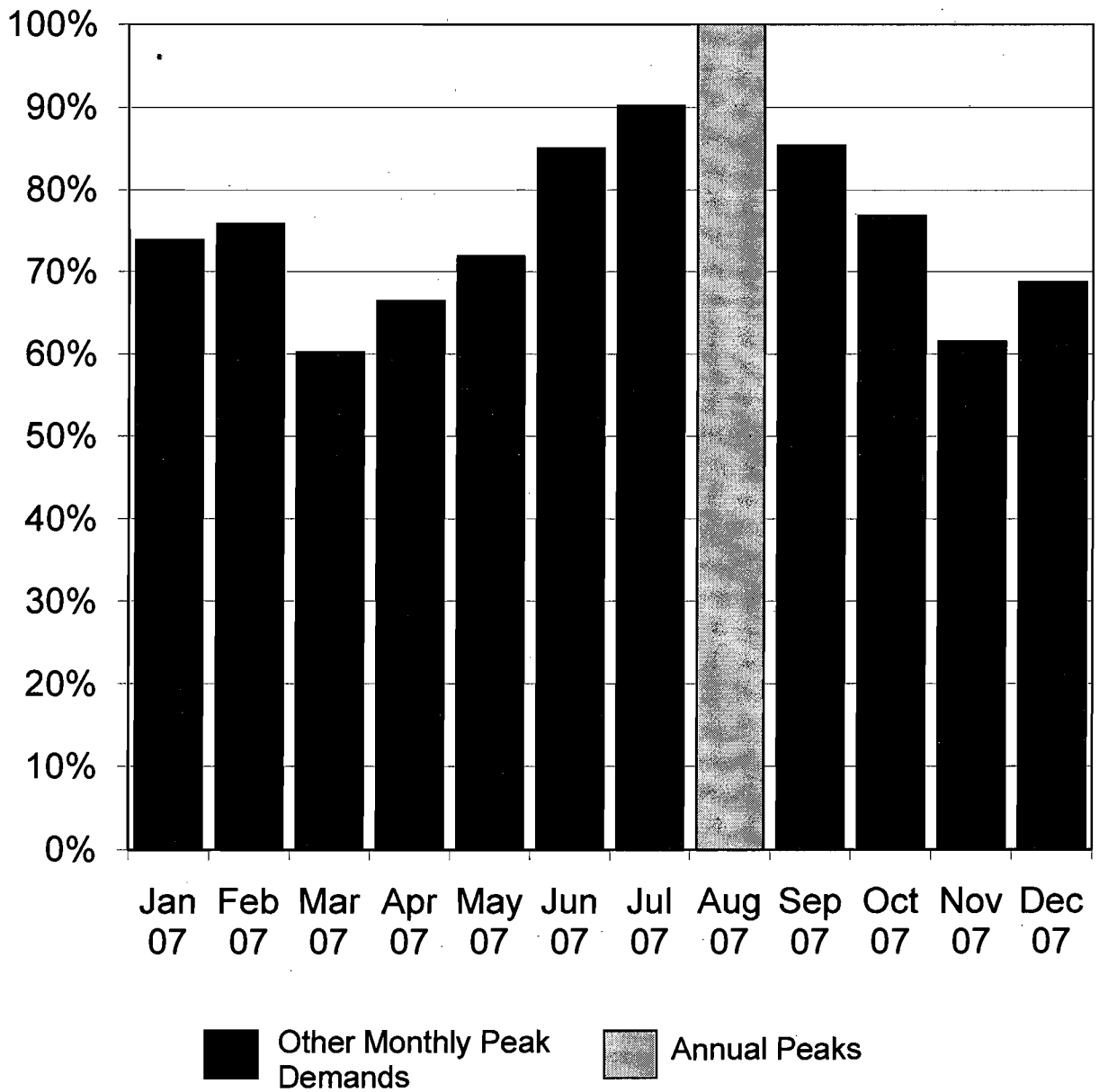
1 Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

2 A Yes, it does.

\\Huey\Share\PL\Docs\TSK\8963\Testimony - BAI\144201.doc

AmerenUE

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



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

<u>Line</u>	<u>Description</u>	Total Company	
		<u>MW</u> (1)	<u>Percent</u> (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

<u>Line</u>	<u>Description</u>	<u>Missouri Retail</u> (1)	<u>Residential</u> (2)	<u>Small General Service</u> (3)	<u>Large General Service</u> (4)	<u>Large Primary Service</u> (5)	<u>Large Trans. Service</u> (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	<u>0.466376</u>	<u>0.276603</u>	<u>0.059495</u>	<u>0.109065</u>	<u>0.020157</u>	<u>0.001056</u>
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
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
<u>RATE BASE ADDITIONS/REDUCTIONS:</u>							
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
<u>OPERATING REVENUES</u>							
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
<u>OPERATING EXPENSES</u>							
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	Adjustment	
		Revenues	Amount	Percent
		(1)	(2)	(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	<u>128,201</u>	<u>(8,896)</u>	(6.9)
		\$2,046,127	- 0 -	- 0 -

ATTACHMENT 1

**NON-
PROPRIETARY
VERSION**