Exhibit No.:	
Issues:	Cost of Service, Revenue Allocation, and Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2021-0240
Date Testimony Prepared:	September 17, 2021

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	**)))))**	**Case No. ER-2021-0240**

Direct Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation and Rate Design

On behalf of

Missouri Industrial Energy Consumers

September 17, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11115

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	)))))	**Case No. ER-2021-0240**

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 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. 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 are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2021-0240.

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
Maurice Brubaker

Subscribed and sworn to before me this 17th day of September, 2021.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2023
Commission # 15024862

Tammy S Klossner
Notary Public

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<u>Direct Testimony of Maurice Brubaker</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

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 this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"), a non-profit corporation that represents the interests of large consumers in Missouri rate matters.

INTRODUCTION AND SUMMARY

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 Ameren Missouri, to explain how the study should be used, and to recommend an appropriate allocation of any change in 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.

Next, I present the results of the detailed cost of service analysis for Ameren Missouri. This cost study indicates how individual customer class revenues compare to the costs incurred in providing service to them.

The cost of service analysis and interpretation are then followed by recommendations with respect to the allocation of revenues.

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level of rates that should be charged to customers.

2. Ameren Missouri exhibits significant summer peak demands as compared to demands in other months.

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

4. Ameren Missouri utilizes, for its generation allocation, the A&E method using four class non-coincident peaks. While I believe use of the two predominant summer peaks is more conceptually correct, in this case the difference between the two allocation factors for every major class is insignificant. To minimize differences, I have elected to use Ameren Missouri's generation allocation factor.

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. In order to better reflect cost-causation, I have modified Ameren Missouri's treatment of the non-labor component of production non-fuel operation and maintenance ("O&M") expenses. Ameren Missouri allocates a larger proportion of non-fuel production O&M expense on energy than I believe is appropriate. Since these expenses are more a function of the existence of the generation facilities and the passage of time, I have instead classified and allocated them as a demand-related cost.

7. I also have calculated income taxes at current rates based on the taxable income of each class in order to recognize Ameren Missouri's actual total income tax liability at current rates, and the responsibility of each class for that liability. This modification increases the rate of return earned from the Residential class.

8. The results of my class cost of service study are summarized on Schedule MEB-COS-4. As shown on line 25 of Schedule MEB-COS-4, the Residential class is producing a return below the system average. All other major classes, except for the Small General Service class which is currently paying cost-based rates, are producing returns in excess of the system average.

9. Schedule MEB-COS-5 shows the adjustments that would need to take place (before factoring in any potential overall rate change) to move each customer class to cost of service. The Residential class would require a revenue neutral increase of 7.8%. All other major classes would move down toward cost of service if they received a rate decrease.

10. Schedule MEB-COS-6 shows class revenue adjustments required to move 50% toward cost of service. I recommend that the adjustment for all major classes be 50% (the customer-owned lighting class may require some moderation for impact reasons.) Any overall change in revenue should be applied as an equal percent to the base rate revenues of all classes after making the interclass adjustments.

11. For purposes of implementing the final rates in this case, all of the charges in the Large Primary Service Rate, except for the Low-Income Pilot Program Charge, should receive the same percentage change.

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:

- With limited exceptions, it cannot be economically 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 of electricity used over time by a customer (i.e., energy measured in kilowatthours ("kWh")) <u>and</u> the rate of use (i.e., demand, a.k.a. "power"

> measured in kilowatts ("kW")) are important, and both vary significantly from class to class.

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 to 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. The utility must incur the cost of this pathway regardless of the customer's **demand** or **energy** requirements.

Second, even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, air conditioning, perhaps heating, 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 their maximum capacity, which is the maximum kW of electrical 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.

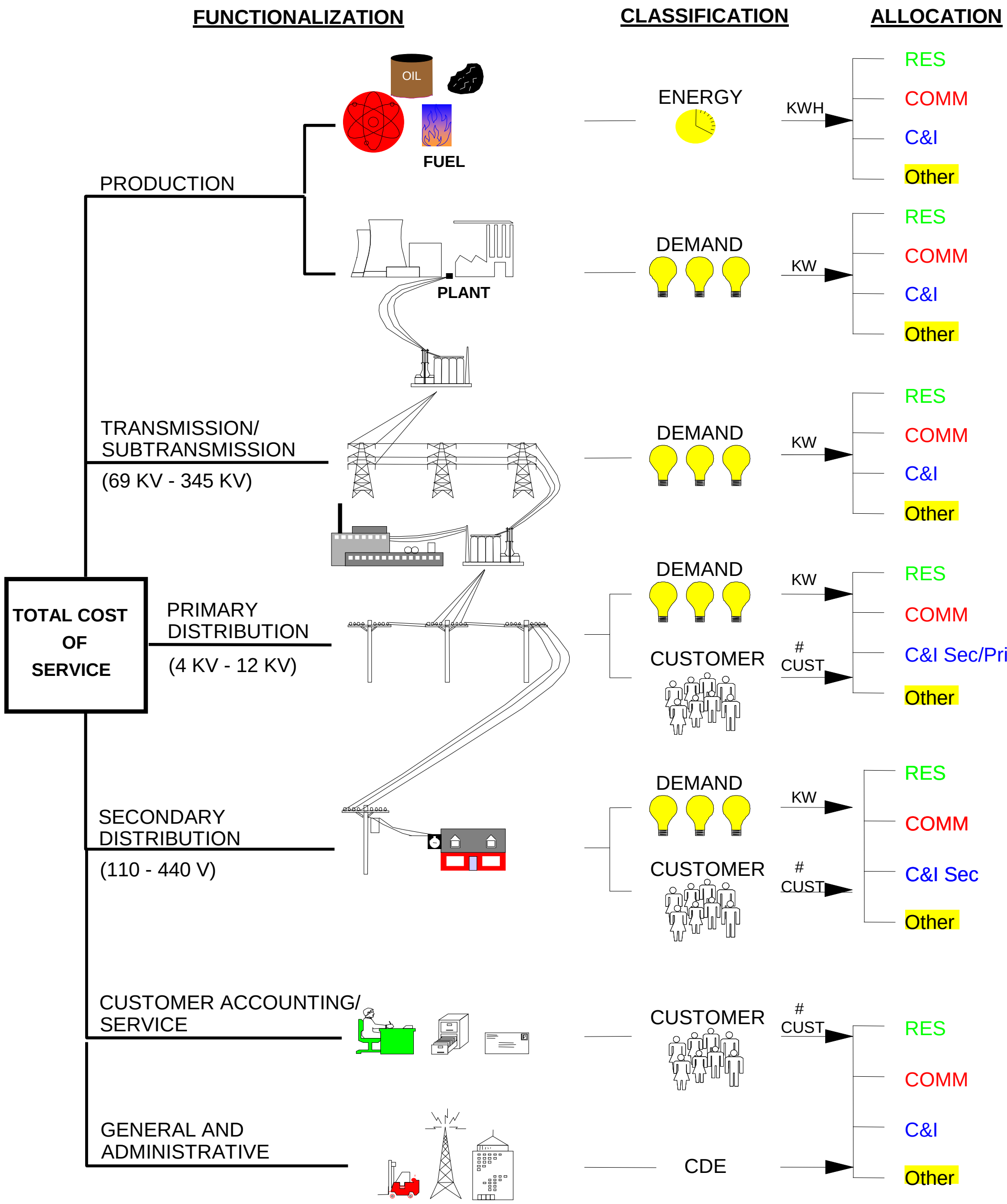
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWh. To see one reason why this isn't accurate, consider a more familiar commodity – tomatoes, for example.

The tomatoes we buy at the supermarket, say for about $2.00 a pound, might originally come from Florida, where they are grown, 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 kW demands whenever they occur.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



Maurice Brubaker
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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, distribution, 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 production. The next level is the extra high voltage transmission and subtransmission system (69,000 volts 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 and pad-mounted transformers at the "secondary" level to 110-440 volts used to serve homes, barbershops, light manufacturing 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 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 door 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 costs to the utility are avoided. (Actually, the reason the utility does not bear these costs is that they are borne by the customer who must invest in the 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 (i.e., the demand). If the utility anticipates a peak demand of 9,000 MW 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 as demand-related. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed O&M 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., kW) that 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.

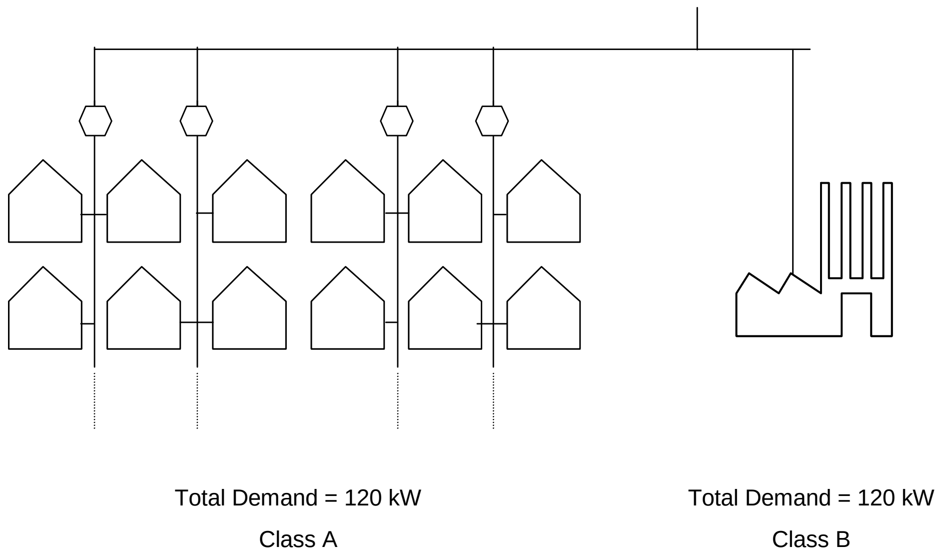
A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to construct a system's electrical pathways that comply with local or national safety and reliability codes, and to attach customers to that system, regardless of their demand or energy requirements. 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 kW 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 capacity of the system required by local or national safety and reliability codes, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2
<u>Classification of Distribution Investment</u>



<u>Demand vs. Energy Costs</u>

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 imposed a higher peak demand, 500 watts per hour or 0.5 kW, than Customer B who demanded only 200 watts per hour or 0.2 kW.

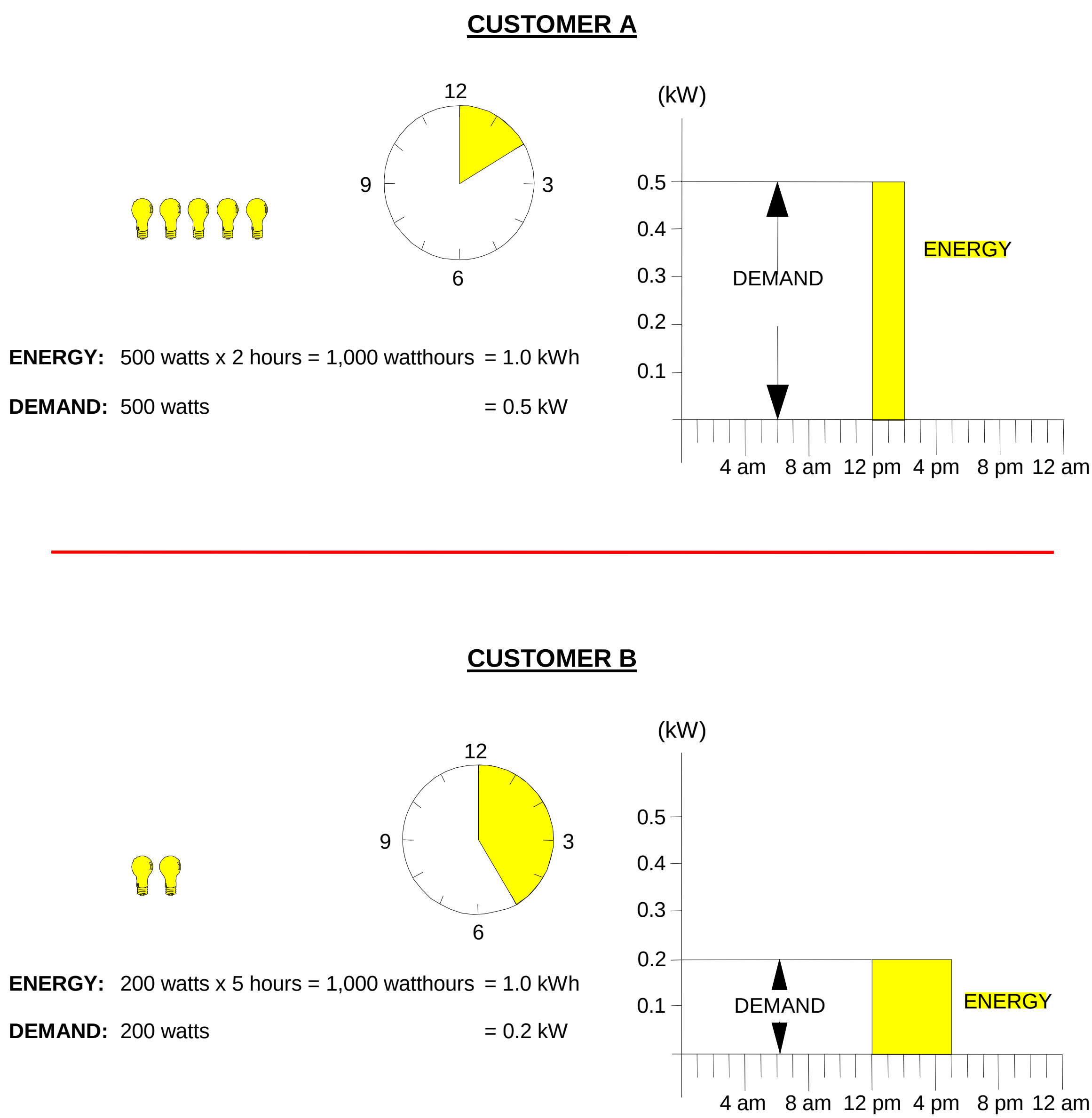
Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity, lines and substations for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

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 across time. 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 kW of demand imposed on the system is much greater in the case of Customer B.

Figure 3

DEMAND VS. ENERGY



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 the customer's 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 average total 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 and a more efficient use of capacity. 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.

Allocation

Q WHAT IS ALLOCATION?

A The final step in the cost of service analysis is the **allocation** of the costs to the customer classes. Factors are developed to allocate the demand, energy and customer-related 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 energy-related 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 Ameren Missouri's retail customers are shown in Table 1.

TABLE 1
Energy Allocation Factor

Rate Class	Energy Generated (MWh) (1)	Allocation Factor (2)
Residential	14,454,222	43.70%
Small GS	3,278,305	9.91%
Large GS/Small Primary	11,488,104	34.74%
Large Primary	3,689,239	11.15%
Comp. Owned Lighting	106,448	0.32%
Cust. Owned Lighting	57,095	0.17%
Total	33,073,413	100.00%

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 below shows the calculation of the factor for Ameren Missouri. (The selection and derivation of this factor is discussed in more detail on pages 24 and 25.)

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 customer classes 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 Ameren Missouri (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. (Class load factors are presented in Table 4, which is discussed later.)

TABLE 2
Demand Allocation Factor
Production System

Rate Class	Production A&E (MW)	Allocation Factor[2]
	(1)	(2)
Residential	3,725	52.53%
Small GS	775	10.93%
Large GS/Small Primary	2,036	28.71%
Large Primary	532	7.50%
Comp. Owned Lighting	15	0.22%
Cust. Owned Lighting	9	0.12%
Total	7,092[1]	100.00%

Notes:
[1] The 7,092 MW is the MO Jurisdictional peak.
[2] Column (2) is the A&E-4NCP allocation factor.

Q THE RATES, WHEN EXPRESSED PER KWH, CHARGED TO LARGE GS/SMALL PRIMARY AND LARGE PRIMARY 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 Large GS/Small Primary and Large Primary 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
at Current Rates
(Dollars in Thousands)

Rate Class	Cost-Based Revenue	Energy Sales (MWh)	Cost per kWh
	(1)	(2)	(3)
Residential	$ 1,372,297	13,384,649	10.25 ¢
Small GS	270,758	3,035,720	8.92
Large GS/Small Primary	656,891	10,746,717	6.11
Large Primary	168,191	3,542,170	4.75
Comp. Owned Lighting	29,480	98,571	29.91
Cust. Owned Lighting	4,379	54,389	8.05
Total	$ 2,501,995	30,862,215	8.11 ¢

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

The Large Primary customers have a higher load factor, 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)	Production A&E (MW)	Load Factor
	(1)	(2)	(3)
Residential	14,454,222	3,725	44%
Small GS	3,278,305	775	48%
Large GS/Small Primary	11,488,104	2,036	64%
Large Primary	3,689,239	532	79%
Comp. Owned Lighting	106,448	15	79%
Cust. Owned Lighting	57,095	9	76%
Total	33,073,413	7,092	53%

In addition, these customers take service at a higher voltage level. This means that they do not cause the utility to incur 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 7.99% at the secondary voltage level and 4.74% at the primary voltage level.

TABLE 5

Energy Loss Factors

Rate Class	Percent of Sales By Voltage Level: Secondary	Percent of Sales By Voltage Level: Primary & Higher	Composite Loss Percentage
	(1)	(2)	(3)
Residential	100%	0%	7.99%
Small GS	100%	0%	7.99%
Large GS/Small Primary	66%	34%	6.90%
Large Primary	0%	100%	4.15%
Comp. Owned Lighting	100%	0%	7.99%
Cust. Owned Lighting	100%	0%	4.97%

Source: Workpapers of Thomas Hickman
Ameren Missouri Cost of Service Study, tabs A.F.1-- 4ncp and kWh's.

The per capita sales to the Large Primary class are also much greater than to the other classes, as shown in Table 6. Ameren Missouri sells over 55 million kWhs per Large Primary customer, but only about 12,500 kWhs per Residential customer, or 4,400 times as much per Large Primary customer, as shown in Table 6. The customer-related costs to serve a Large Primary customer are not 4,400 times the customer-related costs to serve a Residential customer. This is yet another reason why the cost to serve Large Primary customers is significantly less than the cost to serve Residential and Commercial customers.

TABLE 6
Energy Sold Per Customer

Rate Class	Energy Sold (MWh)	Average Number of Customers	kWh Sold per Customer
	(1)	(2)	(3)
Residential	13,384,649	1,073,414	12,469
Small GS	3,035,720	151,762	20,003
Large GS/Small Primary	10,746,717	11,318	949,524
Large Primary	3,542,170	64	55,346,409
Comp. Owned Lighting	98,571	53,094	1,857
Cust. Owned Lighting	54,389	1,630	33,367
Total	30,862,215	1,291,282	23,900

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 Load Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

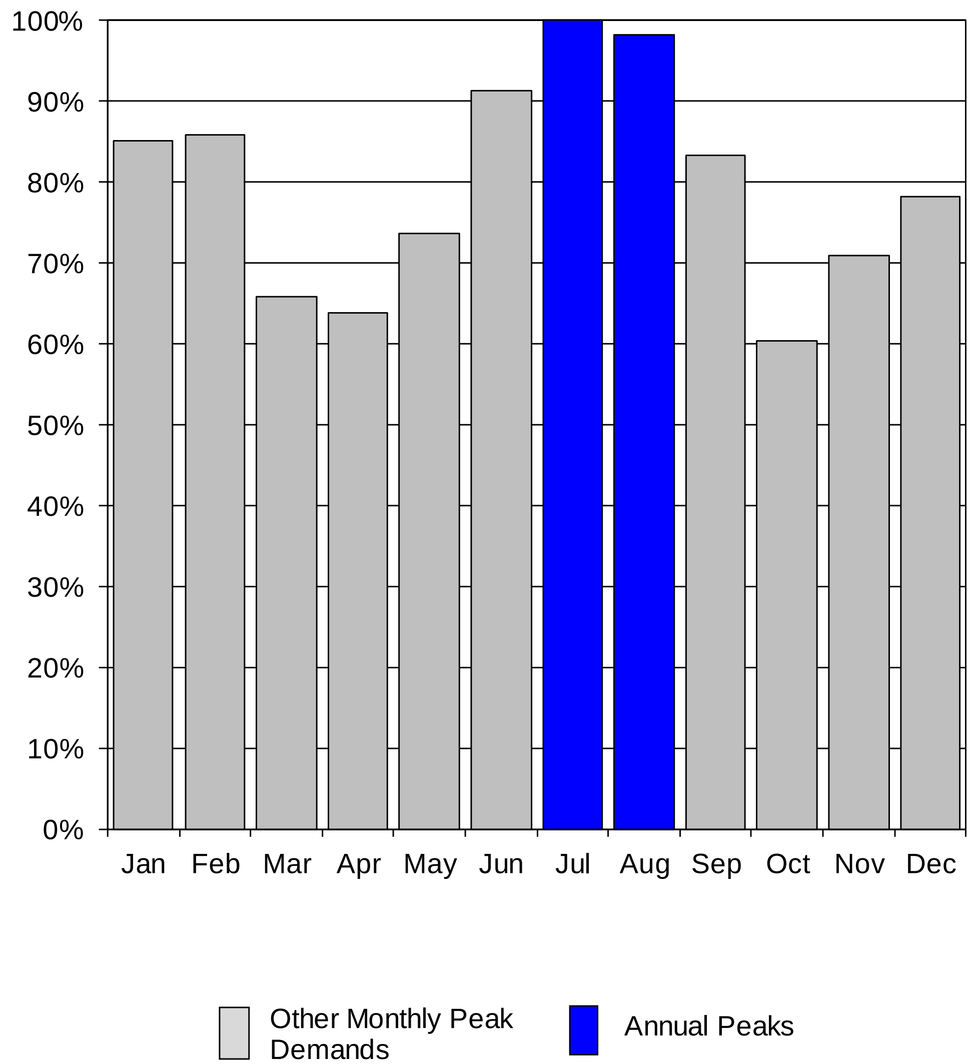
A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed, or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for Ameren Missouri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

Figure 4

AMEREN MISSOURI

Case No. ER-2021-0240

**Analysis of Ameren's (Missouri) Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended December 2020**



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

2 highlighted bars show the months in which the highest peaks occurred.

This analysis shows that summer peaks dominate the Ameren Missouri system. (This same information is presented in tabular form on Schedule MEB-COS-2.) The system peak occurred in July, with a just slightly lower peak demand in August. The June peak was 91% of the annual peak. The monthly peaks occurring in the other months were substantially lower. These lower loads simply are not representative of peak-making weather and use of these lower demands as part of the allocation factor could 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 cause 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's 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 AMEREN MISSOURI SYSTEM?

A As noted, the Ameren Missouri load pattern has predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission costs. 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 peak method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of Ameren Missouri, this would be one or more peaks occurring during the summer.

Q WHAT IS THE A&E METHOD?

A Unlike the coincident peak method which relies strictly on a class's relative contribution to one or more utility peaks, the A&E method is one of a family of methods that 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.

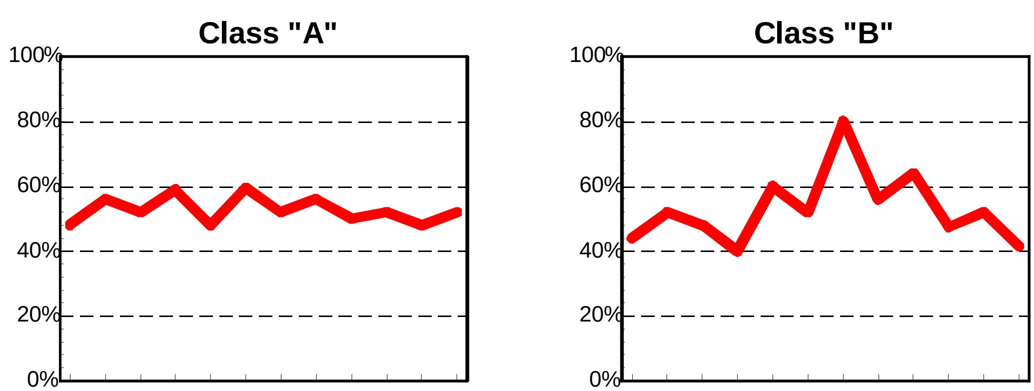
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability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

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[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.

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 maximum demands of its customers. There also may be higher costs as a result of the greater variability in 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 that has caused, and continues to cause, the utility to maintain and/or expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

Either a coincident peak allocation, using the demands during the peak summer months, or a version of an A&E allocation that uses class non-coincident peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results of both methods should be similar as long as only summer period peak loads are used. Like Ameren Missouri, 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 time of occurrence of the 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 four annual class non-coincident peaks.

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

A Line 2 shows the average of the four months' non-coincident peaks (the highest demands, regardless of when they occur) for each class. Line 3 shows the annual amount of energy required by each class. Line 4 is the average demand, in kW, which is determined by dividing the annual energy in line 3 by the number of hours (8,760) in a year. Line 5 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown on line 6, is equal to the non-coincident peak demand shown on line 2 minus the average demand that is shown on line 4. Line 7 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. Line 8 is the result of multiplying the annual load factor (53.23%) by each class's average demand percent from line 5. Line 9 is the result of multiplying the quantity one minus the system load factor (46.26%) by each class's excess demand percent from line 7.

Finally, line 10 presents the composite A&E allocation factor, which is the sum of lines 8 and 9. As noted, it is determined by weighting the average demand responsibility of each class (which is the same as each class's energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

Q **RECOGNIZING THAT YOU RECOMMEND THE A&E-4NCP ALLOCATION METHOD FOR GENERATION FIXED COSTS THAT AMEREN MISSOURI RECOMMENDS, DID YOU ALSO EXAMINE OTHER ALLOCATION METHODS THAT COULD BE CONSIDERED APPROPRIATE FOR AMEREN MISSOURI?**

A Yes. A&E-4NCP is one of several allocation methods that could be considered appropriate in light of the strong summer peaking characteristics of Ameren Missouri.

Q **HAVE YOU CALCULATED THE ALLOCATION FACTORS ASSOCIATED WITH ANY OF THESE OTHER ALLOCATION METHODS WHICH COULD BE CONSIDERED?**

A Yes. Schedule MEB-COS-3A shows the allocation factors for the A&E-4NCP method along with other reasonable allocation methods.

Q **PLEASE DESCRIBE THESE OTHER METHODS.**

A From an overall perspective, each of these other methods recognize the strong summer peaking nature of the Ameren Missouri system by focusing on demands imposed on the system by the major customer classes during the summer period.

Q **WHAT ARE THESE OTHER METHODS?**

A As shown on Schedule MEB-COS-3A, they are A&E-2NCP, A&E-1NCP, 4CP, 2CP, 1CP, 4NCP, 2NCP and 1NCP.

Q CONSISTENT WITH RSMO SECTION 393.1620, ARE EACH OF THE ALLOCATION METHODS SHOWN ON SCHEDULES MEB-COS-3 AND MEB-COS-3A SET FORTH IN THE 1992 ELECTRIC UTILITY COST ALLOCATION MANUAL PUBLISHED BY THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC")?

A Yes.

Q HOW WOULD YOU CHARACTERIZE THE OVERALL ALLOCATION FACTOR CHOICES FOR THE RESIDENTIAL CLASS AND FOR THE LPS CLASS?

A Looking at column (2) on Schedule MEB-COS-3A for the Residential class, it should be noted that none of the other allocation factor choices allocates less cost to the Residential class than does the A&E-4NCP method. Also, none of the other allocation factor choices allocate more cost to the LPS class than does the A&E-4NCP method.

Q PLEASE SUMMARIZE THIS ANALYSIS AND THE RESULTS.

A The A&E-4NCP method is a reasonable allocation method. It does not over-allocate cost to the Residential class, nor does it under-allocate costs to the LPS class.

<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. This cost of service study reflects results 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 revenues, expenses and operating income based on my cost of service study.

The next section shows the major elements of rate base, and line 25 shows the rate of return at present rates for each customer class based on this cost of service study and Ameren Missouri's claimed revenues, expenses and rate base.

Q HOW DOES YOUR STUDY DIFFER FROM THE ONE PRESENTED BY AMEREN MISSOURI?

A There are differences in the classification of certain non-fuel generation O&M expenses.

In addition, I have calculated the income taxes at present rates based on the taxable income of each class, instead of allocating income taxes on rate base. This approach changes the rates of return at present rates, but (when applied consistently) does not change the amount of the increase or decrease required to move to cost of service.

Q PLEASE ELABORATE ON THE DIFFERENT TREATMENT OF INCOME TAXES.

A To determine the amount of income tax attributable to individual customer classes under current rates, Ameren Missouri allocates income taxes to classes based on each class's rate base as a percentage of total rate base. This calculation essentially assumes that each customer class is producing the system average rate of return. However, the rates of return earned from the different classes are not equal, so Ameren Missouri's approach to allocating income taxes on rate base has the effect of over-allocating income taxes to classes whose rates of return are below average, and under-allocating income taxes to classes whose rates of return are above average. In my cost of service study, I have corrected for this problem by calculating income taxes separately for each customer class using a method that recognizes the pre-tax income and the appropriate income tax deductions for each class under current rates, and calculates the income tax obligation of each customer class as a function of its taxable income. This has the effect of increasing the income tax attributable to classes earning above the system average rate of return, and reducing the income taxes charged to customers earning less than the system average rate of return. My adjustment produces a higher earned rate of return under current rates for the Residential class than does Ameren Missouri's method.

Q DO YOU TAKE ISSUE WITH ANY OTHER ELEMENTS OF AMEREN MISSOURI'S CLASS COST OF SERVICE STUDY?

A Yes. There are two other areas where there are differences. The first is the allocation of transmission costs, and the second is the classification of certain non-fuel generation O&M expenses.

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

A Ameren Missouri 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; it was not built to meet the average of the 12 monthly peak demands, some of which are significantly lower (as much as 40% lower) 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 HAVE YOU MODIFIED AMEREN MISSOURI'S CLASS COST OF SERVICE STUDY TO IMPLEMENT THIS CHANGE IN THE ALLOCATION OF TRANSMISSION COSTS?

A No. In looking at the difference in allocation factors, I determined that the dollar amounts of change would not be material, and so in order to narrow the issues, I have simply used Ameren Missouri's allocation of transmission system costs.

Q WHAT IS THE ISSUE WITH RESPECT TO THE CLASSIFICATION OF CERTAIN NON-FUEL GENERATION O&M EXPENSES?

A The issue involves the classification of non-labor generation costs (other than fuel and purchased power) between the "fixed" category and the "variable" category. The categories of costs, broadly speaking, are non-labor costs in the generation operations cost category and the generation maintenance category. Classification is important in cost of service studies because fixed costs are allocated on the production demand allocation factor, while variable costs are allocated on the production energy allocation factor. These factors are significantly different among classes, so the issue of classification is very important.

Q WHAT IS YOUR POSITION ON HOW THESE GENERATION COSTS OTHER THAN FUEL AND PURCHASED POWER SHOULD BE ALLOCATED?

A It is my position that the vast majority of these costs do not vary in any appreciable way with the number of kWh generated, but occur primarily as a function of the existence of the plants, the hours of operation and the passage of time. In fact, Ameren Missouri schedules the maintenance on its coal and nuclear generation units on a "passage of time" basis, not on a "kWh generated" basis. I believe the most appropriate approach is to classify all of the generation O&M expense other than fuel and purchased power as a fixed cost. This is sometimes referred as the "expenses follow plant" basis. It is the basis that generally has been used in Missouri for classification and allocation of these costs.

Q TO WHAT EXTENT DOES AMEREN MISSOURI TAKE A DIFFERENT APPROACH?

A Historically, Ameren Missouri has classified significant amounts of both labor and non-labor costs as variable. In this case, Ameren Missouri has classified the labor component of generation O&M expense (except for fuel handling) as a fixed cost. This is consistent with the approach that I have used, and thus there is no longer a difference in the treatment of the labor component.

There does, however, remain some difference in the treatment of costs other than labor. Ameren Missouri has moved some of these other costs that it previously classified as energy-related into the fixed cost category, and I concur in this move. Thus, the remaining difference between my approach and Ameren Missouri's is approximately $69 million with respect to generation non-labor O&M expense other than fuel and purchased power.

Q WHERE ARE THE RESULTS OF MIEC'S COST OF SERVICE STUDY SHOWN?

A The results at present rates are summarized on Schedule MEB-COS-4.

Q HAVE YOU PROVIDED THE DETAILED CALCULATIONS SUPPORTING YOUR CLASS COST OF SERVICE STUDY?

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

Q HOW DID YOU USE AMEREN MISSOURI'S COST OF SERVICE MODEL IN PRODUCING YOUR CLASS COST OF SERVICE STUDY?

A It was the starting point. The results of Ameren Missouri's allocation first were replicated by utilizing the data contained in its cost of service model. Many of Ameren Missouri's allocation factors and functionalizations and classifications have been utilized. The principal areas where I depart from Ameren Missouri and use a different approach were incorporated into the allocations. They have been explained previously 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 primary basis used to establish the revenues collected from each customer class and to design rate schedules.

Factors such as simplicity, gradualism and ease of administration may also be taken into account, but 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.

Electric rates also play a role in economic development, both with respect to job creation and job retention. This is particularly true in the case of industries where electricity is one of the largest components of the cost of production.

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 in most cases is 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 misled 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 ("EE") 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 based on an under-priced rate, the 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 EE or demand response 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 rate is 6¢ per kWh.

The importance of this concept is underscored by the large dollar amount associated with EE programs that will be incorporated into Ameren Missouri's Integrated Resource Plan (Ameren Missouri 2020 IRP, MO PSC Case. No. EO-2021-0021, Chapter 8). The costs expended pursuant to the Missouri Energy Efficiency Investment Act ("MEEIA") are likely to exceed $1 billion over the next ten years. This is a significant commitment of dollars and a large amount of the cost is for programs associated with residential customers. Cost-based rates for residential customers will provide higher rewards to customers who implement these programs. Failure to fully price the residential rates, and to reflect the cost of EE programs in the residential rate, will diminish the likelihood that these programs will be successful.

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.

Q ARE THERE CIRCUMSTANCES WHERE IT IS APPROPRIATE TO CONSIDER FACTORS OTHER THAN COST-BASED ALLOCATION?

A Yes, when retention or attraction of load requires a discount and when other customers are better off if that load is served, even at a lower price. The impact on the state's economy may also be a factor to be considered.

Revenue Allocation

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

A Small General Service customers are the closest to system average rate of return, while the Residential class is well below, and the Large Primary Service, Large General Service/Small Primary[3] and Lighting classes are above the system average rate of return.

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[3]Although separate rate classes, the Large General Service and Small Primary rate classes are lumped together for the purpose of conducting the class cost of service study.

Q WHAT ADJUSTMENTS TO REVENUES WOULD BE REQUIRED AT PRESENT RATES TO MOVE ALL CLASSES TO COST OF SERVICE?

A This is shown on Schedule MEB-COS-5. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall change in revenues for the utility. Note that the Residential class would require an increase of about $99 million, or 7.8%, in order to move to cost of service. All other major classes would require a corresponding decrease. The decreases range from about 1.3% for the Small General Service class to 10.8% for the Large Primary class.

Q HOW DOES AMEREN MISSOURI PROPOSE TO ADJUST REVENUES?

A Ameren Missouri proposes essentially an equal percentage across-the-board decrease.

Q WOULD AMEREN MISSOURI'S ALLOCATION MOVE CLASS RATES CLOSER TO COST OF SERVICE?

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

Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF AMEREN MISSOURI'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 Ameren Missouri 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 proposal is shown on Schedule MEB-COS-6. Column 1 shows class revenues at current rates. Column 2 shows the proposed cost of service adjustment. This adjustment moves classes roughly 50% of the way toward cost of service. An even larger movement would not be unreasonable. Indeed, given the many years that the residential class has been under-priced, a failure to make a significant move toward cost-based rates would be unreasonable.

While some will want to talk about the impact on the Residential class of this approach, 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 unfairly benefit the residential class by bearing more of the burden of the revenue responsibility than they should. Moving 50% of the way toward cost of service requires a Residential class revenue-neutral adjustment of only 3.9% (as compared to the 7.8% 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 bear part of the revenue responsibility that rightly should be shouldered by the Residential class.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

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

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

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

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

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

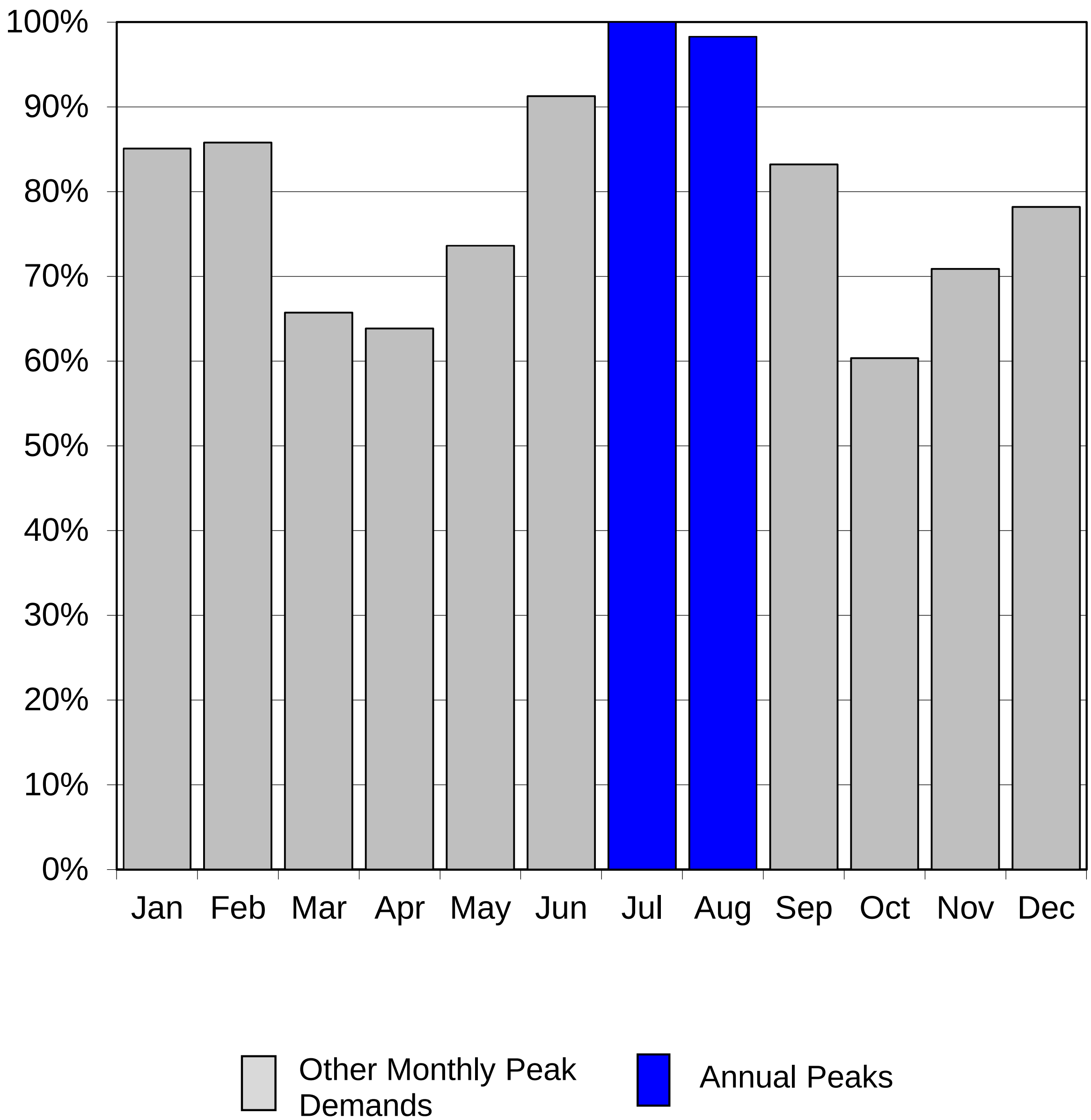
An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

421102

AMEREN MISSOURI
Case No. ER-2021-0240

Analysis of Ameren's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses)
For the Test Year Ended December 2020



AMEREN MISSOURI
Case No. ER-2021-0240

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 December 2020

Line	Description	Total Company MW (1)	Percent (2)
1	January	6,034	85.1%
2	February	6,085	85.8%
3	March	4,662	65.7%
4	April	4,527	63.8%
5	May	5,221	73.6%
6	June	6,473	91.3%
7	July	7,092	100.0%
8	August	6,970	98.3%
9	September	5,901	83.2%
10	October	4,280	60.3%
11	November	5,027	70.9%
12	December	5,546	78.2%

Source: Ameren Missouri COS, System_CP Worksheet

AMEREN MISSOURI
Case No. ER-2021-0240

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended December 2020

Line	Description	Missouri Total	Residential	Small Gen. Service	Large G.S./ Sm Primary	Large Primary	Company Owned Lighting	Customer Owned Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak	7,092						
2	Avg of 4 Highest Monthly NCP Values	7,061	3,696	769	2,026	530	25	15
3	Energy Sales with Losses - MWh	33,073,413	14,454,222	3,278,305	11,488,104	3,689,239	106,448	57,095
4	Average Demand - MW	3,775.5	1,650.0	374.2	1,311.4	421.1	12.2	6.5
5	Average Demand - Percent	100.0%	43.7%	9.9%	34.7%	11.2%	0.3%	0.2%
6	Class Excess Demand - MW	3,270.1	2,046.0	395.1	714.8	108.9	3.2	2.1
7	Class Excess Demand - Percent	100.0%	62.6%	12.1%	21.9%	3.3%	0.1%	0.1%
	Allocator:							
8	Annual Load Factor * Average Demand	0.532331	0.232647	0.052766	0.184906	0.059380	0.001713	0.000919
9	(1-LF) * Excess Demand	0.467669	0.292609	0.056506	0.102226	0.015573	0.000460	0.000294
10	Average and Excess Demand Allocator	1.000000	0.525256	0.109272	0.287132	0.074953	0.002174	0.001213

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	53.23%
1 - Load Factor	46.77%

Source: Ameren Missouri COS, A.F.1-4NCP Worksheet.

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Production Allocation Factors

Line	Description	System (1)	Residential (2)	SGS (3)	LGS/SPS (4)	LPS (5)	Company Owned Lighting (6)	Customer Owned Lighting (7)
1	A&E 4 NCP	100.0%	52.5%	10.9%	28.7%	7.5%	0.2%	0.1%
2	A&E 2 NCP	100.0%	52.5%	11.1%	28.7%	7.4%	0.2%	0.1%
3	A&E 1 NCP	100.0%	52.6%	11.1%	28.6%	7.4%	0.2%	0.1%
4	4 CP	100.0%	52.9%	10.5%	29.0%	7.5%	0.0%	0.0%
5	2 CP	100.0%	53.4%	10.9%	28.4%	7.4%	0.0%	0.0%
6	1 CP	100.0%	53.3%	10.9%	28.6%	7.2%	0.0%	0.0%
7	4 NCP	100.0%	52.3%	10.9%	28.7%	7.5%	0.4%	0.2%
8	2 NCP	100.0%	52.7%	11.2%	28.4%	7.2%	0.3%	0.2%
9	1 NCP	100.0%	52.9%	11.1%	28.2%	7.2%	0.3%	0.2%

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Electric Cost of Service Allocation Study
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Includes MIEC Classification Adjustments and MIEC's Alternative Income Tax Calculation
(Dollars in Thousands)

Line	Description	Missouri Total (1)	Residential (2)	Small Gen. Service (3)	Large G.S./ Sm Primary (4)	Large Primary (5)	Company Owned Lighting (6)	Customer Owned Lighting (7)
1	Base Revenue	$ 2,501,995	$ 1,273,043	$ 274,322	$ 727,565	$ 188,576	$ 35,640	$ 2,849
2	Other Revenue	85,760	48,149	9,121	21,969	5,503	918	100
3	Lighting Revenue	-	-	-	-	-	-	-
4	System, Off-Sys Sales & Disp of Allow	325,300	142,307	32,276	113,104	36,322	840	451
5	Rate Revenue Variance	-	-	-	-	-	-	-
6	Total Operating Revenue	2,913,055	1,463,499	315,719	862,639	230,401	37,398	3,399
7	Total Prod, T&D, Cust and A&G Expense	1,593,655	818,596	165,978	462,406	132,219	11,666	2,790
8	Total Depreciation and Ammortization Expenses	765,832	433,537	85,002	189,916	44,834	11,328	1,215
9	Real Estate and Property Taxes	156,958	89,547	17,499	38,225	8,858	2,588	240
10	Income Taxes	(105,328)	(83,495)	(10,726)	(9,275)	(1,287)	14	(559)
11	Payroll Taxes	22,954	12,897	2,461	5,835	1,460	242	58
12	Federal Excise Taxes	-	-	-	-	-	-	-
13	Revenue Taxes	-	-	-	-	-	-	-
14	Total Operating Expenses	2,434,071	1,271,082	260,214	687,107	186,084	25,840	3,744
15	Net Operating Income	478,984	192,416	55,506	175,531	44,317	11,558	(345)
16	Gross Plant in Service	21,398,230	12,200,746	2,382,447	5,220,321	1,213,251	348,161	33,303
17	Reserves for Depreciation	8,805,955	5,145,882	983,961	2,034,261	466,658	162,465	12,728
18	Net Plant in Service	12,592,275	7,054,864	1,398,486	3,186,060	746,593	185,696	20,574
19	Materials & Supplies - Fuel	253,969	111,102	25,199	88,303	28,357	656	352
20	Materials & Supplies - Local	255,168	166,847	29,825	41,533	5,536	10,872	555
21	Cash Working Capital	(26,758)	(13,744)	(2,787)	(7,764)	(2,220)	(196)	(47)
22	Customer Advances & Deposits	(26,697)	(9,565)	(7,962)	(7,150)	-	(2,018)	(1)
23	Accumulated Deferred Income Taxes	(2,994,782)	(1,708,570)	(333,887)	(729,346)	(169,012)	(49,387)	(4,581)
24	Total Net Original Cost Rate Base	$ 10,053,175	$ 5,600,934	$ 1,108,873	$ 2,571,637	$ 609,255	$ 145,623	$ 16,853
25	Rate of Return	4.765%	3.435%	5.006%	6.826%	7.274%	7.937%	-2.045%

Schedule MEB-COS-4

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TITLE: NET ORIGINAL COST - PAGE 1

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL (1)	RESIDENTIAL (2)	SMALL GEN SERVICE (3)	LARGE G.S./ SM PRIMARY (4)	LARGE PRIMARY (5)	COMPANY OWN LIGHITNG (6)	CUSTOMER OWN LIGHTING (7)
1		PRODUCTION	A.F.1	$ 6,413,307	$ 3,368,711	$ 700,810	$ 1,841,493	$ 480,702	$ 13,858	$ 7,733
2										
3		TRANSMISSION								
4		LINES	A.F.2	$ 728,505	$ 371,758	$ 76,237	$ 220,244	$ 59,672	$ 390	$ 204
5		SUBSTATION	A.F.3	$ 378,809	$ 193,307	$ 39,642	$ 114,523	$ 31,028	$ 203	$ 106
6										
7		TOTAL TRANSMISSION		$ 1,107,315	$ 565,065	$ 115,879	$ 334,766	$ 90,701	$ 593	$ 311
8										
9		DISTRIBUTION PLANT								
10										
11	360	SUBSTATION LAND	A.F.8	$ 22,464	$ 11,950	$ 2,519	$ 6,403	$ 1,471	$ 77	$ 44
12	321	OTHER LAND	A.F.5	$ 14,123	$ 7,817	$ 1,648	$ 4,176	$ 403	$ 50	$ 29
13										
14	361-362	SUBSTATIONS	A.F.8	$ 941,742	$ 500,965	$ 105,620	$ 268,426	$ 61,661	$ 3,225	$ 1,845
15										
16	364	POLES TOWERS FIXTURES								
17		CUSTOMER	A.F.4	$ 93,127	$ 77,430	$ 10,947	$ 800	$ 2	$ 3,830	$ 118
18		HV	A.F.5a	$ 15,071	$ 8,024	$ 1,692	$ 4,287	$ 988	$ 52	$ 30
19		PRIMARY	A.F.5b	$ 28,952	$ 16,025	$ 3,379	$ 8,561	$ 826	$ 103	$ 59
20		SECONDARY	A.F.6	$ 14,761	$ 9,214	$ 1,943	$ 3,511	$ -	$ 59	$ 34
21		LIGHTING-DIRECT	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22										
23		SUBTOTAL		$ 151,911	$ 110,692	$ 17,960	$ 17,158	$ 1,816	$ 4,044	$ 240
24										
25	365	OVERHEAD CONDUCTOR								
26		CUSTOMER	A.F.4	$ 677,932	$ 563,579	$ 79,680	$ 5,917	$ 24	$ 27,876	$ 856
27		HV	A.F.5a	$ 111,099	$ 59,150	$ 12,471	$ 31,600	$ 7,280	$ 381	$ 218
28		PRIMARY	A.F.5b	$ 384,134	$ 212,614	$ 44,826	$ 113,585	$ 10,957	$ 1,369	$ 783
29		SECONDARY	A.F.6	$ 20,167	$ 12,588	$ 2,654	$ 4,797	$ -	$ 81	$ 46
30										
31		SUBTOTAL		$ 1,193,332	$ 847,931	$ 139,631	$ 155,899	$ 18,261	$ 29,707	$ 1,903
32										
33	366	UNDERGROUND CONDUIT								
34		CUSTOMER	A.F.4	$ 140,659	$ 116,934	$ 16,532	$ 1,227	$ 5	$ 5,784	$ 178
35		HV	A.F.5a	$ 27,967	$ 14,890	$ 3,139	$ 7,954	$ 1,833	$ 96	$ 55
36		PRIMARY	A.F.5b	$ 201,644	$ 111,608	$ 23,531	$ 59,624	$ 5,752	$ 719	$ 411
37		SECONDARY	A.F.6	$ 88,951	$ 55,523	$ 11,706	$ 21,159	$ -	$ 357	$ 205
38										
39		SUBTOTAL		$ 459,221	$ 298,954	$ 54,908	$ 89,965	$ 7,589	$ 6,956	$ 848
40										
41	367	UNDERGROUND CONDUCTORS								
42		CUSTOMER	A.F.4	$ 202,989	$ 168,751	$ 23,858	$ 1,771	$ 7	$ 8,347	$ 256
43		HV	A.F.5a	$ 40,359	$ 21,487	$ 4,530	$ 11,479	$ 2,645	$ 138	$ 79
44		PRIMARY	A.F.5b	$ 290,998	$ 161,064	$ 33,958	$ 86,045	$ 8,301	$ 1,037	$ 593
45		SECONDARY	A.F.6	$ 128,368	$ 80,127	$ 16,893	$ 30,536	$ -	$ 516	$ 295
46										
47		SUBTOTAL		$ 662,714	$ 431,429	$ 79,240	$ 129,831	$ 10,952	$ 10,038	$ 1,224

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TITLE: NET ORIGINAL COST - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL (1)	RESIDENTIAL (2)	SMALL GEN SERVICE (3)	LARGE G.S./ SM PRIMARY (4)	LARGE PRIMARY (5)	COMPANY OWN LIGHITNG (6)	CUSTOMER OWN LIGHTING (7)
1										
2	368	LINE TRANSFORMERS								
3		CUSTOMER	A.F.15	$ 152,481	$ 126,826	$ 17,931	$ 1,258	$ -	$ 6,273	$ 193
4		SECONDARY	A.F.6	$ 164,001	$ 102,370	$ 21,583	$ 39,012	$ -	$ 659	$ 377
5										
6		SUBTOTAL		$ 316,482	$ 229,196	$ 39,514	$ 40,271	$ -	$ 6,932	$ 570
7										
8	369-1	OVERHEAD SERVICES								
9		CUSTOMER	A.F.15	$ (30,959)	$ (26,890)	$ (3,802)	$ (267)	$ -	$ -	$ -
10		SECONDARY	A.F.16	$ (45,017)	$ (31,766)	$ (5,900)	$ (7,351)	$ -	$ -	$ -
11										
12		SUBTOTAL		$ (75,976)	$ (58,656)	$ (9,702)	$ (7,617)	$ -	$ -	$ -
13										
14	369-2	UNDERGROUND SERVICES								
15		CUSTOMER	A.F.15	$ 34,767	$ 30,198	$ 4,269	$ 300	$ -	$ -	$ -
16		SECONDARY	A.F.16	$ 1,993	$ 1,406	$ 261	$ 325	$ -	$ -	$ -
17										
18		SUBTOTAL		$ 36,760	$ 31,604	$ 4,531	$ 625	$ -	$ -	$ -
19										
20	370	METERS	A.F.7	$ 143,142	$ 87,833	$ 27,193	$ 22,403	$ 2,487	$ -	$ 3,226
21										
22	371	CUSTOMER INSTALLATIONS	DIRECT	$ (5)	$ -	$ -	$ (2)	$ (2)	$ -	$ -
23										
24	373	STREET LIGHTING	A.F.29	$ 98,699	$ -	$ -	$ -	$ -	$ 98,699	$ -
25										
26		SUBTOTAL - CUSTOMER DIST PLANT		$ 1,371,115	$ 1,114,300	$ 170,971	$ 26,384	$ 2,524	$ 52,110	$ 4,826
27		- DEMAND DIST PLANT		$ 2,593,495	$ 1,385,415	$ 292,091	$ 701,154	$ 102,113	$ 107,618	$ 5,103
28										
29		DISTRIBUTION TOTAL		$ 3,964,610	$ 2,499,715	$ 463,062	$ 727,538	$ 104,637	$ 159,728	$ 9,929
30										
31		GENERAL PLANT	A.F.35	$ 598,445	$ 336,263	$ 64,165	$ 152,130	$ 38,065	$ 6,316	$ 1,505
32										
33				$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35				$ -	$ -	$ -	$ -	$ -	$ -	$ -
36										
37		SUBTOTAL PROD,T&D,GEN,COMMON PLANT		$ 12,083,676	$ 6,769,755	$ 1,343,916	$ 3,055,927	$ 714,106	$ 180,495	$ 19,477
38										
39		INTANGIBLE PLANT	A.F.35	$ 295,575	$ 166,082	$ 31,691	$ 75,138	$ 18,801	$ 3,120	$ 743
40		PLANT IN SERVICE ACCOUNTING	PISA	$ 242,925	$ 134,495	$ 26,411	$ 63,371	$ 15,782	$ 2,429	$ 437
41		OVER COLLECTED AMORTIZATIONS	A.F.35	$ (749)	$ (421)	$ (80)	$ (191)	$ (48)	$ (8)	$ (2)
42		PAYS REGULATORY ASSET	DIRECT	$ 3,044	$ 3,044	$ -	$ -	$ -	$ -	$ -
43		REGULATORY ACCOUNT (PENSION, OPEB)	A.F.35	$ (32,197)	$ (18,091)	$ (3,452)	$ (8,185)	$ (2,048)	$ (340)	$ (81)
44										
45		TOTAL NET PLANT		$ 12,592,275	$ 7,054,864	$ 1,398,486	$ 3,186,060	$ 746,593	$ 185,696	$ 20,574

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TITLE: NET ORIGINAL COST - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL (1)	RESIDENTIAL (2)	SMALL GEN SERVICE (3)	LARGE G.S./ SM PRIMARY (4)	LARGE PRIMARY (5)	COMPANY OWN LIGHITNG (6)	CUSTOMER OWN LIGHTING (7)
1		MATERIALS & SUPPLIES - FUEL	A.F.11	$ 253,969	$ 111,102	$ 25,199	$ 88,303	$ 28,357	$ 656	$ 352
2		MATERIALS & SUPPLIES - LOCAL	A.F.18	$ 255,168	$ 166,847	$ 29,825	$ 41,533	$ 5,536	$ 10,872	$ 555
3		CASH WORKING CAPITAL	A.F.37	$ (26,758)	$ (13,744)	$ (2,787)	$ (7,764)	$ (2,220)	$ (196)	$ (47)
4		CUSTOMER ADVANCES & DEPOSITS	A.F.12	$ (26,697)	$ (9,565)	$ (7,962)	$ (7,150)	$ -	$ (2,018)	$ (1)
5		ACCUM DEFERRED INCOME TAXES	A.F.19	$ (2,994,782)	$ (1,708,570)	$ (333,887)	$ (729,346)	$ (169,012)	$ (49,387)	$ (4,581)
6										
7		TOTAL NET ORIGINAL COST RATE BASE		$ 10,053,175	$ 5,600,934	$ 1,108,873	$ 2,571,637	$ 609,255	$ 145,623	$ 16,853

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TITLE: OPERATING EXPENSES - PAGE 1

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	COMP. OWNED LIGHTING LABOR (12)	COMP. OWNED LIGHTING OTHER (13)	CUST. OWNED LIGHTING LABOR (14)	CUST. OWNED LIGHTING OTHER (15)
1		OPERATING EXPENSES																
2																		
3																		
4		PRODUCTION																
5		OTHER	A.F.1/EE	$ 206,138	$ 140,749	$ 346,887	$ 108,278	$ 73,931	$ 22,526	$ 15,380	$ 59,190	$ 40,414	$ 15,451	$ 10,550	$ 445	$ 304	$ 249	$ 170
6		VARIABLE	A.F.11	$ 3,942	$ 673,200	$ 677,142	$ 1,724	$ 294,500	$ 391	$ 66,794	$ 1,371	$ 234,067	$ 440	$ 75,167	$ 10	$ 1,739	$ 5	$ 933
7																		
8		SUBTOTAL		$ 210,080	$ 813,948	$ 1,024,029	$ 110,003	$ 368,431	$ 22,917	$ 82,175	$ 60,560	$ 274,481	$ 15,891	$ 85,717	$ 456	$ 2,043	$ 254	$ 1,102
9																		
10		SYSTEM REVENUE CREDITS																
11		OFF-SYSTEM SALES	A.F.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12		RENTALS	A.F.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13																		
14		SUBTOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15																		
16		TRANSMISSION																
17		LINES	A.F.2	$ 6,137	$ 56,005	$ 62,142	$ 3,132	$ 28,580	$ 642	$ 5,861	$ 1,855	$ 16,932	$ 503	$ 4,587	$ 3	$ 29	$ 2	$ 16
18		SUBSTATIONS	A.F.3	$ -	$ 57,135	$ 57,135	$ -	$ 24,994	$ -	$ 5,669	$ -	$ 19,865	$ -	$ 6,379	$ -	$ 148	$ -	$ 79
19																		
20		TOTAL TRANSMISSION EXPENSES		$ 6,137	$ 113,140	$ 119,277	$ 3,132	$ 53,574	$ 642	$ 11,530	$ 1,855	$ 36,797	$ 503	$ 10,967	$ 3	$ 177	$ 2	$ 96
21																		
22																		
23		DISTRIBUTION OPERATING EXPENSES																
24																		
25																		
26	582	SUBSTATIONS	A.F.8	$ 2,508	$ 1,293	$ 3,801	$ 1,334	$ 688	$ 281	$ 145	$ 715	$ 368	$ 164	$ 85	$ 9	$ 4	$ 5	$ 3
27																		
28	583-1	OVERHEAD LINES																
29		CUSTOMER	A.F.22	$ 2,077	$ 516	$ 2,593	$ 1,723	$ 428	$ 244	$ 61	$ 18	$ 4	$ 0	$ 0	$ 89	$ 22	$ 3	$ 1
30		HV	A.F.23a	$ 354	$ 88	$ 442	$ 189	$ 47	$ 40	$ 10	$ 101	$ 25	$ 23	$ 6	$ 1	$ 0	$ 1	$ 0
31		PRIMARY	A.F.23b	$ 1,159	$ 288	$ 1,447	$ 642	$ 160	$ 135	$ 34	$ 343	$ 85	$ 33	$ 8	$ 4	$ 1	$ 2	$ 1
32		SECONDARY	A.F.24	$ (28)	$ (7)	$ (35)	$ (28)	$ (7)	$ (4)	$ (1)	$ 3	$ 1	$ -	$ -	$ 0	$ 0	$ 0	$ 0
33		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34																		
35		SUBTOTAL		$ 3,562	$ 886	$ 4,448	$ 2,526	$ 628	$ 415	$ 103	$ 464	$ 115	$ 56	$ 14	$ 95	$ 24	$ 6	$ 1
36																		
37	583-2	OVERHEAD TRANSFORMERS																
38		CUSTOMER	A.F.20	$ 1,149	$ 1,598	$ 2,747	$ 956	$ 1,329	$ 135	$ 188	$ 9	$ 13	$ -	$ -	$ 47	$ 66	$ 1	$ 2
39		SECONDARY	A.F.21	$ 1,236	$ 1,719	$ 2,955	$ 772	$ 1,073	$ 163	$ 226	$ 294	$ 409	$ -	$ -	$ 5	$ 7	$ 3	$ 4
40																		
41		SUBTOTAL		$ 2,385	$ 3,317	$ 5,702	$ 1,727	$ 2,402	$ 298	$ 414	$ 304	$ 422	$ -	$ -	$ 52	$ 73	$ 4	$ 6

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TITLE: OPERATING EXPENSES - PAGE 2

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		COMP. OWNED LIGHTING		CUST. OWNED LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR (1)	OTHER (2)	TOTAL (3)	LABOR (4)	OTHER (5)	LABOR (6)	OTHER (7)	LABOR (8)	OTHER (9)	LABOR (10)	OTHER (11)	LABOR (12)	OTHER (13)	LABOR (14)	OTHER (15)
1																		
2	584-1	UNDERGROUND LINES																
3		CUSTOMER	A.F.26	$ 383	$ 526	$ 908	$ 320	$ 439	$ 45	$ 62	$ 3	$ 5	$ 0	$ 0	$ 14	$ 20	$ 0	$ 1
4		HV	A.F.27a	$ 69	$ 95	$ 164	$ 37	$ 51	$ 8	$ 11	$ 20	$ 27	$ 5	$ 6	$ 0	$ 0	$ 0	$ 0
5		PRIMARY	A.F.27b	$ 498	$ 684	$ 1,183	$ 276	$ 379	$ 58	$ 80	$ 147	$ 202	$ 14	$ 20	$ 2	$ 2	$ 1	$ 1
6		SECONDARY	A.F.28	$ 222	$ 305	$ 526	$ 139	$ 190	$ 29	$ 40	$ 53	$ 72	$ -	$ -	$ 1	$ 1	$ 1	$ 1
7																		
8		SUBTOTAL		$ 1,172	$ 1,609	$ 2,781	$ 771	$ 1,058	$ 140	$ 193	$ 223	$ 306	$ 19	$ 26	$ 17	$ 24	$ 2	$ 3
9																		
10	584-2	UNDERGROUND TRANSFORMERS																
11		CUSTOMER	A.F.20	$ 666	$ 453	$ 1,119	$ 554	$ 377	$ 78	$ 53	$ 5	$ 4	$ -	$ -	$ 27	$ 19	$ 1	$ 1
12		SECONDARY	A.F.21	$ 716	$ 487	$ 1,204	$ 447	$ 304	$ 94	$ 64	$ 170	$ 116	$ -	$ -	$ 3	$ 2	$ 2	$ 1
13																		
14		SUBTOTAL		$ 1,382	$ 940	$ 2,323	$ 1,001	$ 681	$ 173	$ 117	$ 176	$ 120	$ -	$ -	$ 30	$ 21	$ 2	$ 2
15																		
16	585	LIGHTING		$ 772	$ 569	$ 1,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 772	$ 569	$ -	$ -
17																		
18	586	METERS	A.F.7	$ 5,607	$ 515	$ 6,122	$ 3,440	$ 316	$ 1,065	$ 98	$ 878	$ 81	$ 97	$ 9	$ -	$ -	$ 126	$ 12
19																		
20	587	CUSTOMER INSTALLATION	DIRECT	$ 1,257	$ (20)	$ 1,237	$ (282)	$ 4	$ -	$ -	$ 769	$ (12)	$ 769	$ (12)	$ -	$ -	$ -	$ -
21																		
22		DIST OPERATING EXPENSE SUBTOTAL																
23		CUSTOMER A582-A587		$ 9,882	$ 3,608	$ 13,490	$ 6,993	$ 2,889	$ 1,567	$ 462	$ 914	$ 107	$ 98	$ 9	$ 178	$ 126	$ 132	$ 15
24		DEMAND A582-A587		$ 8,764	$ 5,501	$ 14,265	$ 3,524	$ 2,888	$ 805	$ 608	$ 2,615	$ 1,294	$ 1,009	$ 112	$ 797	$ 588	$ 14	$ 11
25																		
26	580	SUPERVISION & ENGR																
27		CUSTOMER	A.F.30	$ 3,516	$ 293	$ 3,809	$ 2,488	$ 235	$ 558	$ 37	$ 325	$ 9	$ 35	$ 1	$ 63	$ 10	$ 47	$ 1
28		DEMAND	A.F.31	$ 3,118	$ 447	$ 3,565	$ 1,254	$ 234	$ 286	$ 49	$ 930	$ 105	$ 359	$ 9	$ 284	$ 48	$ 5	$ 1
29																		
30		SUBTOTAL		$ 6,634	$ 739	$ 7,374	$ 3,742	$ 469	$ 844	$ 87	$ 1,255	$ 114	$ 394	$ 10	$ 347	$ 58	$ 52	$ 2
31																		
32	581	DISPATCHING																
33		CUSTOMER	A.F.30	$ 903	$ 46	$ 949	$ 639	$ 37	$ 143	$ 6	$ 84	$ 1	$ 9	$ 0	$ 16	$ 2	$ 12	$ 0
34		DEMAND	A.F.31	$ 801	$ 70	$ 870	$ 322	$ 37	$ 74	$ 8	$ 239	$ 16	$ 92	$ 1	$ 73	$ 7	$ 1	$ 0
35																		
36		SUBTOTAL		$ 1,704	$ 115	$ 1,819	$ 961	$ 73	$ 217	$ 14	$ 322	$ 18	$ 101	$ 2	$ 89	$ 9	$ 13	$ 0
37																		
38	588	MISCELLANEOUS																
39		CUSTOMER	A.F.30	$ 3,836	$ 6,673	$ 10,509	$ 2,714	$ 5,344	$ 608	$ 854	$ 355	$ 197	$ 38	$ 17	$ 69	$ 233	$ 51	$ 29
40		DEMAND	A.F.31	$ 3,401	$ 10,173	$ 13,574	$ 1,368	$ 5,341	$ 312	$ 1,125	$ 1,015	$ 2,392	$ 391	$ 208	$ 309	$ 1,087	$ 6	$ 20
41																		
42		SUBTOTAL		$ 7,237	$ 16,846	$ 24,083	$ 4,082	$ 10,685	$ 921	$ 1,979	$ 1,370	$ 2,590	$ 429	$ 224	$ 378	$ 1,320	$ 57	$ 48

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(Dollars in Thousands)

TITLE: OPERATING EXPENSES - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	COMP. OWNED LIGHTING LABOR (12)	COMP. OWNED LIGHTING OTHER (13)	CUST. OWNED LIGHTING LABOR (14)	CUST. OWNED LIGHTING OTHER (15)
1																		
2	589	RENTS																
3		CUSTOMER	A.F.30	$ -	$ 150	$ 150	$ -	$ 120	$ -	$ 19	$ -	$ 4	$ -	$ 0	$ -	$ 5	$ -	$ 1
4		DEMAND	A.F.31	$ -	$ 228	$ 228	$ -	$ 120	$ -	$ 25	$ -	$ 54	$ -	$ 5	$ -	$ 24	$ -	$ 0
5																		
6		SUBTOTAL		$ -	$ 378	$ 378	$ -	$ 239	$ -	$ 44	$ -	$ 58	$ -	$ 5	$ -	$ 30	$ -	$ 1
7																		
8		DIST OPERATING EXPENSE SUBTOTAL																
9		CUSTOMER A580-589		$ 18,136	$ 10,770	$ 28,906	$ 12,835	$ 8,624	$ 2,877	$ 1,378	$ 1,677	$ 318	$ 179	$ 27	$ 327	$ 376	$ 242	$ 46
10		DEMAND A580-589		$ 16,084	$ 16,418	$ 32,502	$ 6,468	$ 8,620	$ 1,477	$ 1,816	$ 4,798	$ 3,861	$ 1,851	$ 335	$ 1,463	$ 1,754	$ 26	$ 32
11																		
12		TOTAL DIST OPERATING EXPENSES		$ 34,220	$ 27,188	$ 61,408	$ 19,303	$ 17,244	$ 4,354	$ 3,194	$ 6,476	$ 4,179	$ 2,030	$ 362	$ 1,789	$ 2,130	$ 268	$ 78
13																		
14																		
15		DISTRIBUTION MAINTENANCE EXPENSES																
16																		
17																		
18	591-592	SUBSTATIONS	A.F.8	$ 12,133	$ 5,030	$ 17,163	$ 6,454	$ 2,676	$ 1,361	$ 564	$ 3,458	$ 1,434	$ 794	$ 329	$ 42	$ 17	$ 24	$ 10
19																		
20	593	OVERHEAD LINES																
21		CUSTOMER	A.F.22	$ 6,433	$ 25,020	$ 31,453	$ 5,338	$ 20,761	$ 755	$ 2,935	$ 56	$ 218	$ 0	$ 1	$ 276	$ 1,072	$ 8	$ 33
22		HV	A.F.23a	$ 1,097	$ 4,265	$ 5,362	$ 584	$ 2,271	$ 123	$ 479	$ 312	$ 1,213	$ 72	$ 280	$ 4	$ 15	$ 2	$ 8
23		PRIMARY	A.F.23b	$ 3,591	$ 13,965	$ 17,555	$ 1,987	$ 7,729	$ 419	$ 1,630	$ 1,062	$ 4,129	$ 102	$ 398	$ 13	$ 50	$ 7	$ 28
24		SECONDARY	A.F.24	$ (88)	$ (341)	$ (429)	$ (87)	$ (337)	$ (11)	$ (44)	$ 8	$ 32	$ -	$ -	$ 1	$ 5	$ 1	$ 3
25		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26																		
27		SUBTOTAL		$ 11,033	$ 42,909	$ 53,942	$ 7,823	$ 30,424	$ 1,286	$ 5,000	$ 1,438	$ 5,593	$ 175	$ 679	$ 293	$ 1,141	$ 19	$ 72
28																		
29	594	UNDERGROUND LINES																
30		CUSTOMER	A.F.26	$ 923	$ 624	$ 1,546	$ 770	$ 520	$ 109	$ 74	$ 8	$ 5	$ 0	$ 0	$ 34	$ 23	$ 1	$ 1
31		HV	A.F.27a	$ 167	$ 113	$ 279	$ 89	$ 60	$ 19	$ 13	$ 47	$ 32	$ 11	$ 7	$ 1	$ 0	$ 0	$ 0
32		PRIMARY	A.F.27b	$ 1,201	$ 812	$ 2,013	$ 665	$ 449	$ 140	$ 95	$ 355	$ 240	$ 34	$ 23	$ 4	$ 3	$ 2	$ 2
33		SECONDARY	A.F.28	$ 535	$ 361	$ 896	$ 334	$ 226	$ 70	$ 48	$ 127	$ 86	$ -	$ -	$ 2	$ 1	$ 1	$ 1
34																		
35		SUBTOTAL		$ 2,825	$ 1,909	$ 4,735	$ 1,858	$ 1,256	$ 338	$ 229	$ 537	$ 363	$ 45	$ 31	$ 41	$ 28	$ 5	$ 3
36																		
37	595	LINE TRANSFORMERS																
38		CUSTOMER	A.F.20	$ 159	$ 100	$ 259	$ 132	$ 83	$ 19	$ 12	$ 1	$ 1	$ -	$ -	$ 7	$ 4	$ 0	$ 0
39		SECONDARY	A.F.21	$ 171	$ 108	$ 279	$ 107	$ 67	$ 23	$ 14	$ 41	$ 26	$ -	$ -	$ 1	$ 0	$ 0	$ 0
40																		
41		SUBTOTAL		$ 330	$ 208	$ 538	$ 239	$ 151	$ 41	$ 26	$ 42	$ 26	$ -	$ -	$ 7	$ 5	$ 1	$ 0
42																		
43	596	LIGHTING		$ 412	$ 126	$ 538	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 369	$ 113	$ 43	$ 13
44																		
45	597	METERS	A.F.7	$ 762	$ 112	$ 874	$ 468	$ 69	$ 145	$ 21	$ 119	$ 18	$ 13	$ 2	$ -	$ -	$ 17	$ 3
46																		
47		DIST MAINTENANCE EXPENSE SUBTOTAL																
48		CUSTOMER A593-A597		$ 8,277	$ 25,855	$ 34,133	$ 6,708	$ 21,433	$ 1,027	$ 3,042	$ 185	$ 242	$ 13	$ 3	$ 317	$ 1,099	$ 27	$ 36
49		DEMAND A593-A597		$ 19,218	$ 24,439	$ 43,657	$ 10,133	$ 13,142	$ 2,143	$ 2,798	$ 5,410	$ 7,192	$ 1,014	$ 1,038	$ 436	$ 204	$ 82	$ 66

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(Dollars in Thousands)

TITLE: OPERATING EXPENSES - PAGE 4

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		COMP. OWNED LIGHTING		CUST. OWNED LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR (1)	OTHER (2)	TOTAL (3)	LABOR (4)	OTHER (5)	LABOR (6)	OTHER (7)	LABOR (8)	OTHER (9)	LABOR (10)	OTHER (11)	LABOR (12)	OTHER (13)	LABOR (14)	OTHER (15)
1																		
2	590	SUPERVISION & ENGR																
3		CUSTOMER	A.F.32	$ 280	$ 122	$ 403	$ 227	$ 102	$ 35	$ 14	$ 6	$ 1	$ 0	$ 0	$ 11	$ 5	$ 1	$ 0
4		DEMAND	A.F.33	$ 651	$ 116	$ 767	$ 343	$ 62	$ 73	$ 13	$ 183	$ 34	$ 34	$ 5	$ 15	$ 1	$ 3	$ 0
5																		
6		SUBTOTAL		$ 931	$ 238	$ 1,169	$ 570	$ 164	$ 107	$ 28	$ 190	$ 35	$ 35	$ 5	$ 25	$ 6	$ 4	$ 0
7																		
8	598	MISCELLANEOUS																
9		CUSTOMER	A.F.32	$ 229	$ 228	$ 457	$ 186	$ 189	$ 28	$ 27	$ 5	$ 2	$ 0	$ 0	$ 9	$ 10	$ 1	$ 0
10		DEMAND	A.F.33	$ 532	$ 215	$ 748	$ 281	$ 116	$ 59	$ 25	$ 150	$ 63	$ 28	$ 9	$ 12	$ 2	$ 2	$ 1
11																		
12		SUBTOTAL		$ 762	$ 443	$ 1,205	$ 467	$ 305	$ 88	$ 51	$ 155	$ 65	$ 28	$ 9	$ 21	$ 11	$ 3	$ 1
13		DIST MAINTENANCE EXPENSE SUBTOTAL																
14		CUSTOMER A590-A598		$ 8,787	$ 26,206	$ 34,992	$ 7,121	$ 21,724	$ 1,090	$ 3,083	$ 196	$ 245	$ 14	$ 3	$ 336	$ 1,114	$ 29	$ 37
15		DEMAND A590-A598		$ 20,402	$ 24,770	$ 45,171	$ 10,757	$ 13,320	$ 2,275	$ 2,835	$ 5,743	$ 7,289	$ 1,076	$ 1,052	$ 463	$ 207	$ 87	$ 66
16																		
17		TOTAL MAINTENANCE OPERATING EXPENSE		$ 29,188	$ 50,975	$ 80,164	$ 17,879	$ 35,043	$ 3,366	$ 5,919	$ 5,940	$ 7,535	$ 1,091	$ 1,055	$ 799	$ 1,321	$ 115	$ 103
18																		
19		TOTAL DISTRIBUTION EXPENSES		$ 63,409	$ 78,163	$ 141,572	$ 37,182	$ 52,287	$ 7,719	$ 9,113	$ 12,415	$ 11,714	$ 3,121	$ 1,417	$ 2,588	$ 3,452	$ 383	$ 181

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(Dollars in Thousands)

TITLE: OPERATING EXPENSES - PAGE 5

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	COMP. OWNED LIGHTING LABOR (12)	COMP. OWNED LIGHTING OTHER (13)	CUST. OWNED LIGHTING LABOR (14)	CUST. OWNED LIGHTING OTHER (15)
1																		
2																		
3		CUSTOMER ACCOUNT EXPENSES																
4																		
5	902	METER READING	A.F.7A	$ 142	$ 16,837	$ 16,980	$ 123	$ 14,533	$ 17	$ 1,971	$ 3	$ 310	$ 0	$ 3	$ -	$ -	$ 0	$ 20
6	905	MISCELLANEOUS	A.F.7A	$ 12	$ 349	$ 361	$ 10	$ 301	$ 1	$ 41	$ 0	$ 6	$ 0	$ 0	$ -	$ -	$ 0	$ 0
7	903	CUSTOMER RECORDS	A.F.40	$ 15,625	$ 12,569	$ 28,194	$ 12,416	$ 9,423	$ 892	$ 1,560	$ 2,175	$ 1,525	$ 14	$ 10	$ 32	$ 13	$ 96	$ 38
8	904	UNCOLLECTIBLE ACCOUNTS	A.F.13	$ -	$ 7,892	$ 7,892	$ -	$ 7,332	$ -	$ 411	$ -	$ 124	$ -	$ -	$ -	$ 24	$ -	$ 0
9	903	CREDIT AND COLLECTION	A.F.13	$ 4,851	$ 3,902	$ 8,753	$ 4,017	$ 3,231	$ 354	$ 285	$ 327	$ 263	$ 35	$ 28	$ 116	$ 93	$ 2	$ 2
10		INTEREST ON SURETY DEPOSITS	A.F.12	$ -	$ 1,063	$ 1,063	$ -	$ 381	$ -	$ 317	$ -	$ 285	$ -	$ -	$ -	$ 80	$ -	$ 0
11																		
12		SUBTOTAL		$ 20,630	$ 42,611	$ 63,241	$ 16,566	$ 35,201	$ 1,264	$ 4,585	$ 2,505	$ 2,514	$ 49	$ 41	$ 148	$ 210	$ 98	$ 61
13																		
14	901	SUPERVISION	A.F.34	$ 572	$ -	$ 572	$ 459	$ -	$ 35	$ -	$ 69	$ -	$ 1	$ -	$ 4	$ -	$ 3	$ -
15																		
16		TOTAL CUSTOMER ACCOUNT EXPENSES		$ 21,202	$ 42,611	$ 63,813	$ 17,025	$ 35,201	$ 1,299	$ 4,585	$ 2,574	$ 2,514	$ 50	$ 41	$ 152	$ 210	$ 101	$ 61
17																		
18																		
19		CUSTOMER SERVICE & SALES EXPENSES																
20																		
21	908-1&90	RCS	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	908-916	CUSTOMER SERVICES & SALES	A.F.34	$ 7,020	$ 8,769	$ 15,789	$ 5,637	$ 7,244	$ 430	$ 944	$ 852	$ 517	$ 17	$ 9	$ 50	$ 43	$ 34	$ 12
23																		
24		SUBTOTAL		$ 7,020	$ 8,769	$ 15,789	$ 5,637	$ 7,244	$ 430	$ 944	$ 852	$ 517	$ 17	$ 9	$ 50	$ 43	$ 34	$ 12
25																		
26	907-911	SUPERVISION	A.F.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27																		
28		TOTAL CUSTOMER SERVICE & SALES EXPENSES		$ 7,020	$ 8,769	$ 15,789	$ 5,637	$ 7,244	$ 430	$ 944	$ 852	$ 517	$ 17	$ 9	$ 50	$ 43	$ 34	$ 12
29																		
30		TOTAL PROD, T&D,CUST EXPENSES		$ 307,848	$ 1,056,633	$ 1,364,481	$ 172,978	$ 516,738	$ 33,007	$ 108,345	$ 78,258	$ 326,023	$ 19,581	$ 98,150	$ 3,249	$ 5,924	$ 774	$ 1,452
31																		
32																		
33		A & G EXPENSES																
34																		
35		EPRI	A.F.14	$ -	$ 12,505	$ 12,505	$ -	$ 7,134	$ -	$ 1,394	$ -	$ 3,045	$ -	$ 706	$ -	$ 206	$ -	$ 19
36		OTHER	A.F.35	$ 76,877	$ 139,793	$ 216,670	$ 43,197	$ 78,549	$ 8,243	$ 14,988	$ 19,543	$ 35,537	$ 4,890	$ 8,892	$ 811	$ 1,475	$ 193	$ 351
37																		
38		SUBTOTAL		$ 76,877	$ 152,297	$ 229,174	$ 43,197	$ 85,683	$ 8,243	$ 16,383	$ 19,543	$ 38,582	$ 4,890	$ 9,598	$ 811	$ 1,682	$ 193	$ 371
39																		
40		TOTAL PROD,T&D,CUST,A&G EXPENSES		$ 384,725	$ 1,208,930	$ 1,593,655	$ 216,175	$ 602,421	$ 41,250	$ 124,728	$ 97,801	$ 364,605	$ 24,471	$ 107,748	$ 4,061	$ 7,606	$ 967	$ 1,823

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(Dollars in Thousands)

TITLE: OPERATING EXPENSES - PAGE 6

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		COMP. OWNED LIGHTING		CUST. OWNED LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR (1)	OTHER (2)	TOTAL (3)	LABOR (4)	OTHER (5)	LABOR (6)	OTHER (7)	LABOR (8)	OTHER (9)	LABOR (10)	OTHER (11)	LABOR (12)	OTHER (13)	LABOR (14)	OTHER (15)
1		DEPREC & AMORTIZATION EXPENSES																
2																		
3																		
4		DEPR-PRODUCTION PLANT	A.F.1	-	410,280	410,280	-	215,507	-	44,833	-	117,806	-	30,752	-	887	-	495
5		DEPR-COMMON PLANT	A.F.1	-	12,339	12,339	-	7,004	-	1,352	-	3,053	-	732	-	182	-	17
6		DEPR-TRANSMISSION PLANT	A.F.17	-	38,018	38,018	-	19,401	-	3,978	-	11,494	-	3,114	-	20	-	11
7		DEPR-DISTRIBUTION PLANT	A.F.18	-	218,948	218,948	-	143,163	-	25,591	-	35,638	-	4,750	-	9,329	-	476
8		DEPR-GENERAL PLANT	A.F.35	-	86,248	86,248	-	48,462	-	9,247	-	21,925	-	5,486	-	910	-	217
9																		
10		SUBTOTAL		-	765,832	765,832	-	433,537	-	85,002	-	189,916	-	44,834	-	11,328	-	1,215
11																		
12				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																		
14		TOTAL DEPREC & AMORTIZ EXPENSES		-	765,832	765,832	-	433,537	-	85,002	-	189,916	-	44,834	-	11,328	-	1,215
15																		
16																		
17		OTHER																
18																		
19																		
20		REAL ESTATE & PROPERTY TAXES	A.F.19	-	156,958	156,958	-	89,547	-	17,499	-	38,225	-	8,858	-	2,588	-	240
21		INCOME/CITY EARNINGS TAXES	A.F.29	-	(30,095)	(30,095)	-	(16,767)	-	(3,320)	-	(7,698)	-	(1,824)	-	(435)	-	(51)
22		RETURN	A.F.29	-	703,220	703,220	-	391,785	-	77,566	-	179,886	-	42,617	-	10,170	-	1,195
23		PAYROLL TAXES	A.F.35	-	22,954	22,954	-	12,897	-	2,461	-	5,835	-	1,460	-	242	-	58
24		ENVIRONMENTAL TAX	A.F. 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																		
26		SUBTOTAL		-	853,036	853,036	-	477,463	-	94,206	-	216,248	-	51,111	-	12,566	-	1,442
27																		
28		TOTAL OPERATING & OTHER EXPENSES		384,725	2,827,798	3,212,523	216,175	1,513,420	41,250	303,936	97,801	770,769	24,471	203,693	4,061	31,500	967	4,480
29																		
30																		
31																		
32																		
33		TOTAL COST OF SERVICE		384,725	2,827,798	3,212,523	216,175	1,513,420	41,250	303,936	97,801	770,769	24,471	203,693	4,061	31,500	967	4,480

AMEREN MISSOURI
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Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using MIEC's Modified ECOS at Present Rates
(Dollars in Thousands)

Line	Rate Class	Base Revenues (1)	Current Rate Base (2)	Adjusted Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Equal ROR (6)	Difference in Income (7)	Revenue Change (8)	Percent Change (9)
1	Residential	$ 1,273,043	$ 5,600,934	$ 192,416	3.435%	72	$ 266,857	$ 74,440	$ 99,254	7.8%
2	Small GS	274,322	1,108,873	55,506	5.006%	105	52,832	(2,674)	(3,565)	-1.3%
3	Large GS/Primary	727,565	2,571,637	175,531	6.826%	143	122,526	(53,006)	(70,674)	-9.7%
4	Large Primary	188,576	609,255	44,317	7.274%	153	29,028	(15,289)	(20,385)	-10.8%
5	Company Owned Lighting	35,640	145,623	11,558	7.937%	167	6,938	(4,620)	(6,160)	-17.3%
6	Customer Owned Lighting	2,849	16,853	(345)	-2.045%	-43	803	1,148	1,530	53.7%
7	Total	$ 2,501,995	$ 10,053,175	$ 478,984	4.765%	100	$ 478,984	$ -	$ -	0.0%

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Cost of Service Adjustments for
50% Movement Toward Cost of Service
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 50% Toward Cost Of Service[1] (2)	Adjusted Current Revenue (3)	Revenue-neutral Percent Change in Current Revenue (4)
1	Residential	$ 1,273.0	$ 49.6	$ 1,322.7	3.9 %
2	Small GS	274.3	(1.8)	272.5	(0.6)%
3	Large GS/Primary	727.6	(35.3)	692.2	(4.9)%
4	Large Primary	188.6	(10.2)	178.4	(5.4)%
5	Company Owned Lighting	35.6	(3.1)	32.6	(8.6)%
6	Customer Owned Lighting	2.8	0.8	3.6	26.9 %
7	Total	$ 2,502.0	$ -	$ 2,502.0	0.0 %

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-5, times 50%.

Schedule MEB-COS-6