Exhibit No.:	
Issue:	Cost of Service | Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Missouri Industrial Energy Consumers
Case No.:	ER-2018-0146
Date Testimony Prepared:	July 6, 2018

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

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	)	**Case No. ER-2018-0146**

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers

July 6, 2018

BRUBAKER & ASSOCIATES, INC.

Project 10552

MIEC Exhibit No. 551
Date 10/31/18 Reporter JMB
File No. ER-2018-0146

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	)	**Case No. ER-2018-0146**

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-2018-0146.

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

M T Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 5th day of July, 2018.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2019
Commission # 15024862

Tammy S Klossner

Notary Public

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	Case No. ER-2018-0146

Direct Testimony 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 EDUCATIONAL BACKGROUND AND EXPERIENCE.

A That information is contained 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 company that represents the interests of industrial customers in Missouri utility matters. These companies purchase substantial amounts of electricity from Kansas City Power & Light Greater Missouri Operations Company ("GMO") and the outcome of this proceeding will have an impact on their cost of electricity.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of GMO's class cost of service study, to explain how the study should be used, to recommend an appropriate allocation of any rate increase, and to make rate design recommendations.

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 that should be considered in determining how to allocate these functionalized and classified costs among customer classes.

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

Summary

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

1. Class cost of service is the starting point and the most important guideline for establishing the level of rates charged to customers.
2. GMO exhibits significant summer peak demands as compared to demands in other months. (See Schedule MEB-COS-1)
3. There are two generally accepted methods for allocating generation and transmission fixed costs that would apply to GMO. These are the coincident peak methodology and the average and excess ("A&E") methodology.

4. GMO has presented an A&E – 4 Coincident Peak ("A&E-4CP") class cost of service study.

5. GMO's study is reasonable and I will rely on it.

6. The results of GMO's class cost of service study are presented on Schedule MEB-COS-3 and expanded on Schedule MEB-COS-4, which shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates. They range from an increase of 6.2% for the Residential class to a decrease of 17.6% for the Small General Service class.

7. The rates for some classes of customers are so far from cost of service that equity demands a significant movement toward cost of service be made. With GMO opting for certain provisions included in SB 564 (PISA) that includes a rate increase moratorium, it is important that a significant movement be made now, since the next opportunity will be at least three years from when rates from this case will go into effect.

8. GMO's industrial are near the middle of the pack as compared to 41 Midwestern utility service territories. In order to maintain this positon, it is important to adopt a mainstream cost of service study and use it to set rates.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

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

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

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

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

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

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

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, 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 the maximum demand that can safely be imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 2,000 MW of electricity, the utility must have at least 2,000 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 sy stems cool our homes, schools, offices, and factories.

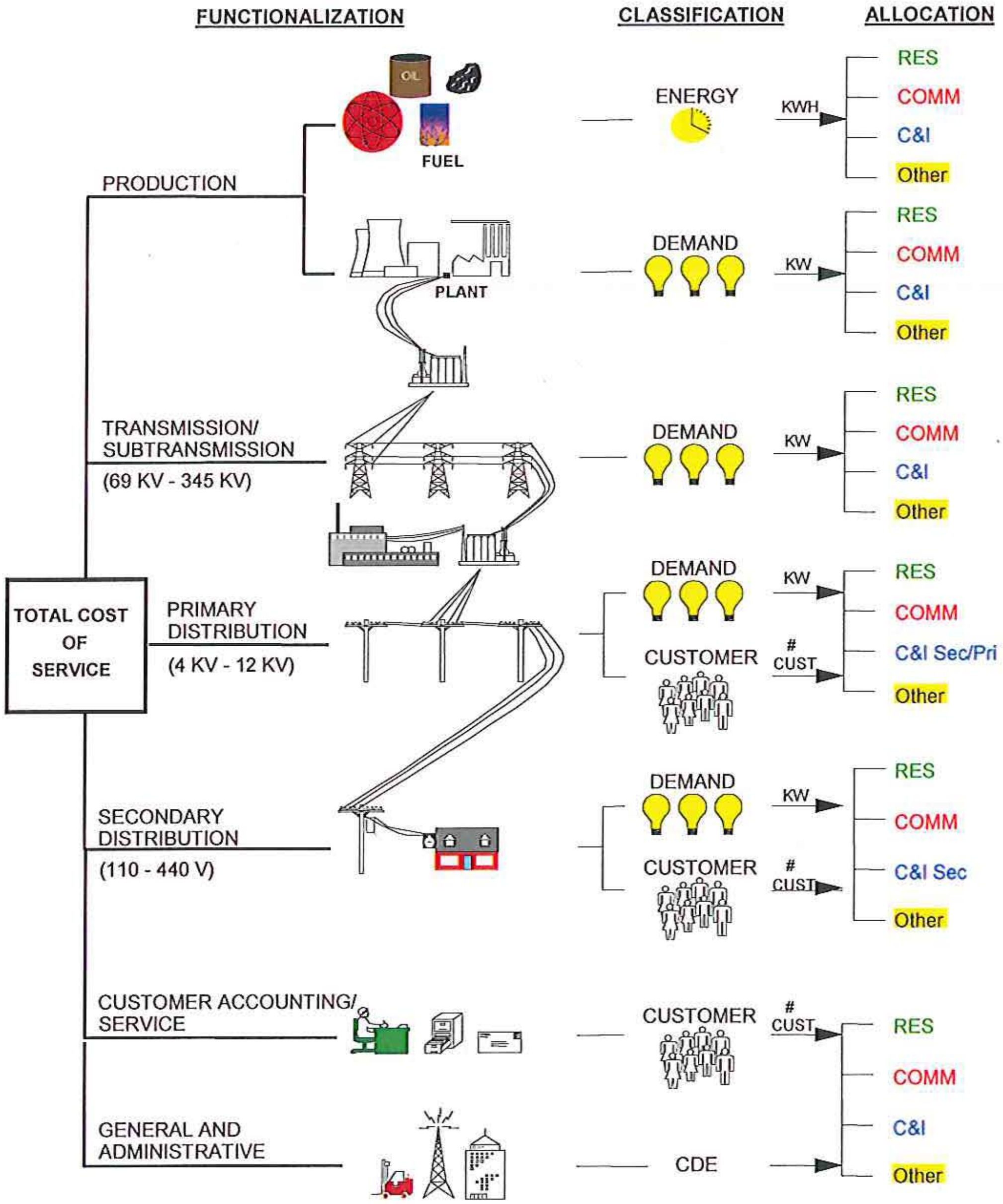
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so simple,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

The tomatoes we buy at the supermarket for about $1.50 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the <u>service</u> of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

As illustrated in Figure 1, electric utilities are similar, except that in most cases (including Missouri), a single company handles everything from production on down through wholesale (bulk and area transmission) and retail (distribution to homes and stores). The crucial difference is that, unlike producers and distributors of tomatoes, electric utilities have an obligation to provide continuous reliable service. The obligation is assumed in return for the exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kWh) requirements of its customers, the obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



Maurice Brubaker

A CLOSER LOOK AT THE COST OF SERVICE STUDY

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

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

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

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

Referring to Figure 1, at the top level there is generation, sometimes called 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 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, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but when you buy a kWh at home you're not only buying the energy itself but also the service of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like some of the Large Power Service customers – pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in transformers and other equipment, or pay separately for some services.)

Classification

Q WHAT IS CLASSIFICATION?

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

Looking at the production function, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 2,000 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).

In almost all hours during the day or during the year, not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance ("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., kilowatts) 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 plant accounts such as poles and overhead conductors.

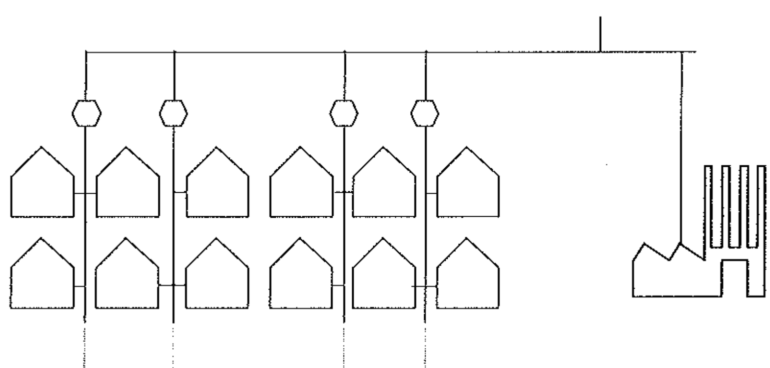
A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends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

Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

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

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

Figure 2
Classification of Distribution Investment



Total Demand = 120 kW
Class A

Total Demand = 120 kW
Class B

Demand vs. Energy Costs

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

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

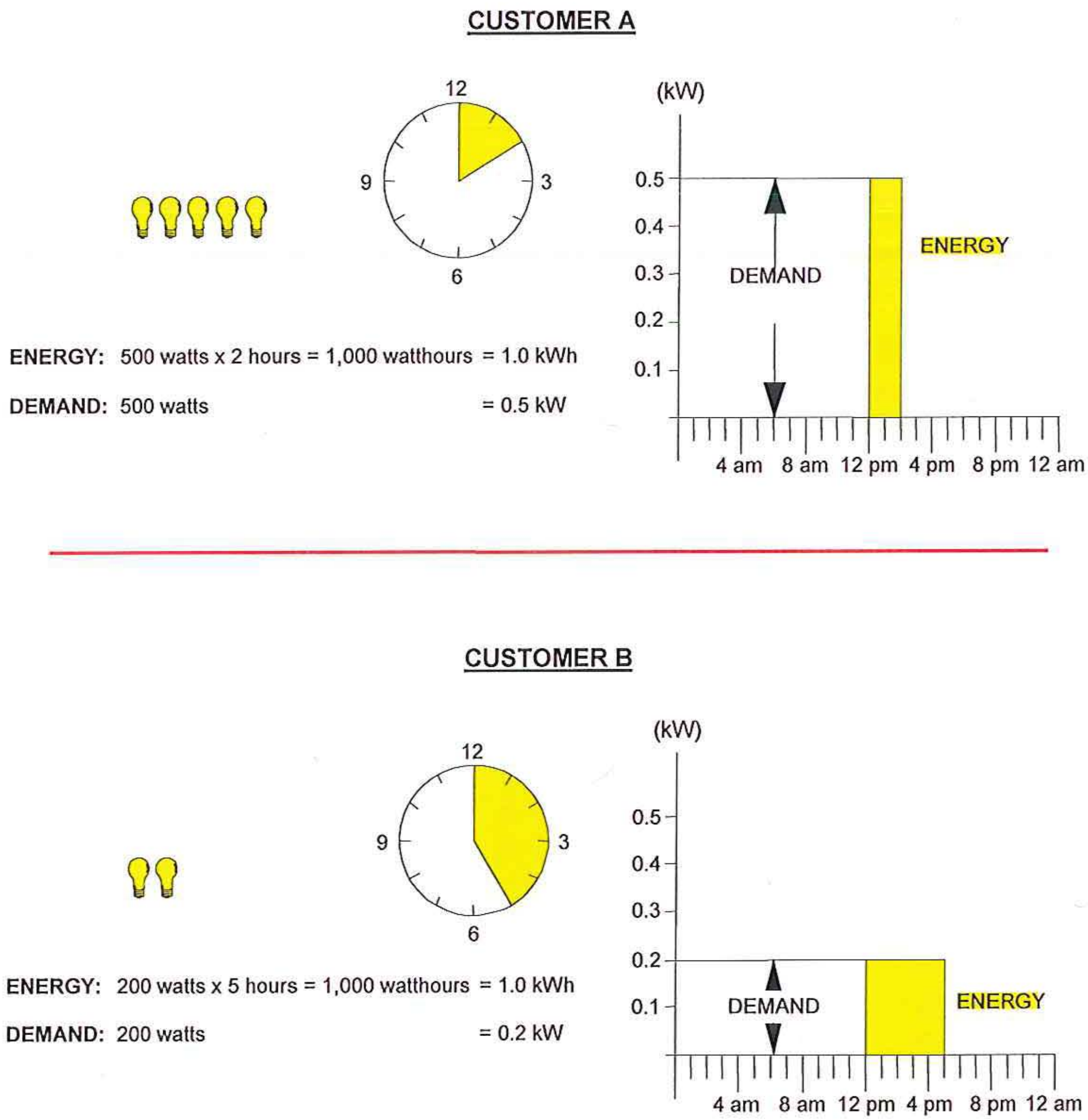
Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy – 1,000 watthours or 1 kWh. However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 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 for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

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

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

Figure 3
DEMAND VS. ENERGY



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

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

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. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. For demand-related costs, we construct an allocation factor by looking at the important class demands.

Utility System Characteristics

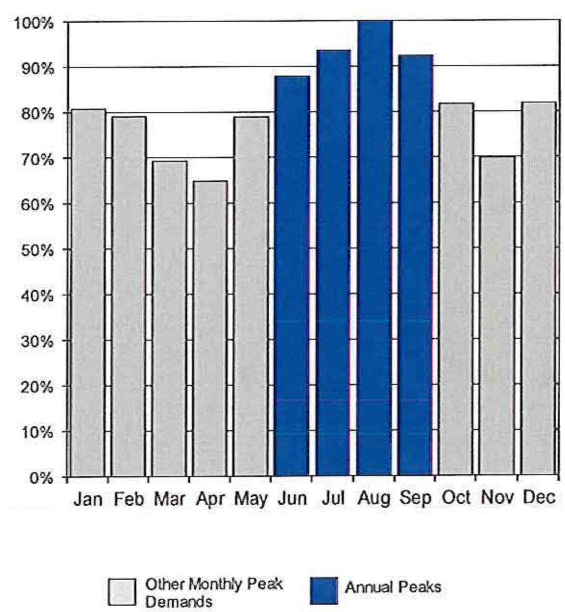
Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method that 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 GMO are shown on Schedule MEB-COS-1. For convenience, it is also shown here as Figure 4.

Figure 4

KCP&L GREATER MISSOURI OPERATIONS COMPANY
Case No. ER-2018-0146

Analysis of KCP&L GMO's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended June 30, 2017



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This shows the monthly system peak demands for the test year used in the study. The highlighted bars show the months in which the highest peak occurred.

This analysis shows that summer peaks dominate the GMO system. (This same information is presented in tabular form on Schedule MEB-COS-2.) This clearly shows that the system peak occurred in August, and was substantially higher than the monthly peaks occurring in most other months. The peaks in June, July and September were only 12.2%, 6.5%, and 7.7%, respectively, lower than the annual peak, while peaks in other months were substantially lower.

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

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

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

A As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class'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 GMO SYSTEM?

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

Q WHAT IS THE A&E METHOD?

A The A&E method is one of a family of methods 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.

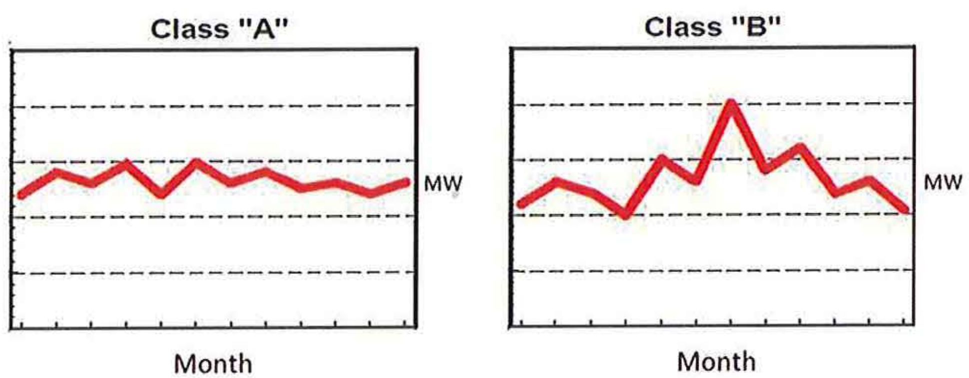
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their contribution to the "peaking"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

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

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

Figure 5

<u>Load Patterns</u>



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[2] than Class A. The greater maximum demand imposes greater costs on the utility system.

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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.

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

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

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 and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

Either a coincident peak study, using the demands during the summer (peak) months, or a version of an A&E cost of service study that uses class demands occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I recommend the A&E method.

Q DO YOU AGREE WITH THE A&E-4CP STUDY PRESENTED BY GMO?

A Yes. Given GMO's load characteristics, I find this study to be reasonable.

Q HAVE YOU HAD OCCASION TO STUDY THE COMPETITIVENESS OF GMO'S INDUSTRIAL RATES?

A Yes. Schedule MEB-COS-2 presents the summary ranking of the rates in 41 Midwestern electric utility company service territories. GMO's rate is in the middle of the pack of this Midwestern utility group. Adoption of a mainstream cost of service study methodology, and adherence to it, are both critical to maintaining the competitiveness of GMO's industrial rates.

<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 THE COST OF SERVICE RESULTS PRESENTED?

A The results are presented in Schedule MEB-COS-3, which reflects results at present rates.

Q REFERRING TO SCHEDULE MEB-COS-3, PLEASE EXPLAIN THE ORGANIZATION AND WHAT IS SHOWN.

A Schedule MEB-COS-3 is a summary of the key elements and the results of GMO's class cost of service study. The top section of the schedule shows the revenues, expenses and operating income based on an A&E-4CP cost of service study.

The next section shows the major elements of rate base, and the rate of return at present rates for each customer class based on this cost of service study.

Adjustment of Class Revenues

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

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

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the 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 is inherently inequitable.

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

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be 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 and demand response programs) depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is subsidized by other customers; that is, the bill is determined using rates that are below cost, that customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

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

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

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

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

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

REVENUE ALLOCATION

Q **PLEASE REFER AGAIN TO SCHEDULE MEB-COS-3 AND SUMMARIZE THE RESULTS OF GMO'S CLASS COST OF SERVICE STUDY.**

A As indicated on line 400 of Schedule MEB-COS-3, the Residential class has a rate of return far below the system average, which means it is not covering its cost of service. On the other hand, all other customers are being charged far more than their cost of service.

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-4. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-3. The remaining columns of Schedule MEB-COS-4 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 increase in revenues. Note that the Residential class would require an increase of about $24 million, or 6.2%, in order to move to cost of service. All other major classes would require a corresponding decrease. The decreases range from about 1.7% for the Medium General Service class to 17.6% for the Small General Service class.

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

A GMO proposes only a very modest recognition of the larger disparities in the revenue/cost relationships of the classes.

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

A Not appreciably. GMO's allocation would essentially maintain the status quo in which the Residential class is below cost of service, and other classes are above cost of service.

Q **DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF GMO'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 GMO (whether an increase or a decrease) 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-5, pages 1 and 2. Column 1 shows class revenues at current rates. Column 2 shows the proposed cost of service adjustment. This adjustment on page 1 moves classes roughly 50% of the way toward cost of service, and the adjustment on page 2 moves 25% of the way toward cost of service. A movement in this range would not be unreasonable. The smaller the overall increase granted to GMO, (or the larger the decrease) the larger the movement toward cost of service can be without causing undue rate shocl.

While some will want to talk about the impact on the Residential class of this increase, it is also important not to lose sight of the fact that by not moving all the way to cost of service, the other customer classes are continuing to support the Residential class by bearing more of the burden of the revenue responsibility than they should. My recommendation of moving 25% to 50% of the way toward cost of service, which limits the Residential class revenue-neutral increase to between 1.6% and 3.1% (as contrasted to the 6.2% increase required to move all the way to cost of service) is relatively moderate, and must be considered in light of the fact that other classes are being asked to continue to provide part of the revenue responsibility that rightly should be shouldered by the Residential class. With GMO opting for certain provisions included in SB 564 (PISA) that includes a rate increase moratorium, it is important that a significant movement be made now, since the next opportunity will be at least three years from when rates from this case will go into effect.

Q **IN ADDITION TO THE FACTORS THAT YOU HAVE NOTED PREVIOUSLY, ARE THERE OTHER REASONS WHY MOVING GMO'S INDUSTRIAL RATES CLOSER TO COST OF SERVICE IS IMPORTANT?**

A Yes. Industrial customers are the most price sensitive, and the level of industrial power rates plays an important role in facility siting decisions and in operating decisions when multi-facility corporations have demands for their product that do not fully load all of their existing facilities. Production (and employment) will generally favor those locations that have the lowest cost, and the cost of utilities is always considered, and frequently is a major factor.

The competitiveness of GMO rates was a factor cited by GMO witness Lutz (at page 6 of his direct testimony), and GMO witness Sullivan (at pages 25-26 of his direct testimony) in GMO's decision to adopt a main-stream cost of service methodology.

Mr. Sullivan's testimony is particularly enlightening with respect to the importance of competition and the level of industrial rates. In discussing why it matters which methodology for cost of service is used by other utilities (he uses Ameren and Westar as examples), Mr. Sullivan states the following at pages 25 and 26 of his direct testimony:

> "The primary reason it matters deals with competition and specifically competition for industrial customers. As discussed earlier in my testimony, GMO's industrial customers generally have a very high load factor, much higher than the system average and much higher than the other customer classes. As will be discussed in the next section of my testimony, of the three methodologies predominantly recommended in Missouri and Kansas, the A&E methodology is the only method that gives a significant recognition to the relative load factors of the customer classes. Further, when a system is not operating at a very high load factor, the A&E methodology best assigns the higher cost of unused capacity.
>
> If the CCOS study is used as a principle tool in assigning the utility revenue requirement to customer classes and thus rate design, industrial cost responsibility and thus industrial rates for utilities using the A&E methodology will be lower than using either of the other two methodologies, all other things being equal. Thus, if the rates for the two major utilities with which GMO competes are using the A&E methodology and GMO is not, GMO will be at a competitive disadvantage in attracting and retaining industrial load.
>
> **Q. Why is it important to attract and retain industrial load?**
>
> A. There are numerous reasons why this is important. First, industrial customers have higher load factors that increase the overall efficiency of the electric system, particularly generation and transmission facilities. The loads are stable throughout the day, allowing the utility to invest in lower cost base load generating

> facilities. Second, industrial customers usually provide a large amount of direct and indirect jobs. The direct jobs are associated with the industrial facility itself. The indirect jobs include the supporting companies that provide materials to the facility and the residential and commercial development supported by the employees of the industrial company."

Although GMO's industrial rates are not as high as KCPL's, they have increased substantially in recent years.

Q HAVE YOU COMPARED THE ESCALATION IN GMO'S RATES WITH THE ESCALATION IN THE RATES OF OTHER UTILITIES IN THE MIDWEST?

A Yes. For the Industrial customers' rates, I have made that comparison. From 2005 to 2017, GMO's industrial rates have increased by 44% for the MPS territory and 69% for the L&P territory as contrasted to an overall increase of approximately 34% for the overall group.

ANALYSIS OF LARGE CUSTOMER RATE STRUCTURE

Q WHAT IS THE STRUCTURE OF THE TARIFFS APPLICABLE TO GMO'S LARGEST CUSTOMERS?

A The LGS and LPS tariffs consist of a series of charges differentiated by voltage level. For LGS there are separate charges for service at primary and secondary voltage levels, and for LPS there are separate charges for service at secondary voltage, service at primary voltage, service at substation voltage, and service at transmission voltage. The rates charged at the higher voltage levels are lower than the rates charged at the lower voltage levels in order to recognize differences in cost of service.

At each voltage level, the rate consists of customer charges, facilities charges, charges for reactive power, demand charges and energy charges. Demand charges and energy charges also are seasonally differentiated, with summer and winter charges.

Q **WHAT IS THE STRUCTURE OF THE DEMAND CHARGES?**

A In addition to being seasonally differentiated, the demand charges at each voltage level consist of multiple block charges.

Q **WHAT IS THE STRUCTURE OF THE ENERGY CHARGES?**

A The two sets of energy charges are structured with three "hours use" blocks. The three blocks consist of the first 180 hours use of the billing demand, the next 180 hours use of the billing demand and the tail block is for consumption in excess of 360 hours use of the billing demand.

These are what are known as hours use, or load factor based charges. The rates decrease as the hours use increases to recognize the spreading of fixed costs over more kilowatthours as the number of hours use, or load factor, increases. This structure also recognizes that energy consumed in the high load factor block likely will be off-peak or at times when energy costs are lower than during on-peak periods.

Q **PLEASE EXPLAIN HOW THE HOURS USE FUNCTION WORKS.**

A The number of kWh to be billed in each hours use block is determined by the customer's billing demand and the amount of kWh purchased.

A customer operating basically a one-day shift (eight hours a day for five days a week) would have usage in the range of 180 kWh per kW of billing demand.[3] A customer operating two shifts likely would utilize approximately twice that much energy, and therefore use an additional 180 or so kWh per kW of demand, thereby filling up both the first and second blocks.

Thus, it is reasonable to consider the first block as being primarily the daytime on-peak hours, the second block for early morning, evening and/or weekend hours, and the third block for additional use in weekend and nighttime hours. Given these considerations, it is appropriate that the energy charges for the initial hours use blocks be higher than for the third hours use block in order to collect more fixed costs during the on-peak and shoulder periods.

Q **CAN YOU ILLUSTRATE WITH AN EXAMPLE OF HOW THE RATE WORKS?**

A Yes. Assume that a customer has a 1,000 kW billing demand, and uses 500,000 kWh in a month. This customer would be using 500 kWh per kW,[4] or 500 kWh for each kW of demand. To apply the rate, the 1,000 kW of demand would be multiplied by 180 kWh per kW, which is the size of the first block, and would result in 180,000 kWh being priced out at the first block. The customer would also fully utilize the second block, so 180,000 kWh would go in it as well and be priced at the second block rate. The remaining 140,000 kWh[5] would be billed in the third, or high load factor, block.

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[3] 8 hours/day x 5 days per week x 4.33 weeks per month = 173 hours
[4] 500,000 ÷ 1,000 kW = 500 kWh/kW
[5] 500,000 - 180,000 - 180,000 = 140,000 kWh

Q **WHAT IS THE LEVEL OF THE ENERGY CHARGES FOR THE HIGH LOAD FACTOR (OVER 360 HOURS USE) BLOCK UNDER CURRENT TARIFFS?**

A The charges vary slightly by voltage level and by season, but range from approximately 3.3¢/kWh to 3.7¢/kWh in LPS and from 3.6¢/kWh to 4.8¢/kWh for LGS.

Q **DO YOU AGREE WITH THE LEVEL OF THE OFF-PEAK ENERGY CHARGES IN THE CURRENT TARIFFS?**

A No, I do not. I believe the high load factor block energy charges collect more fixed costs than is appropriate.

Q **PLEASE EXPLAIN.**

A I have analyzed GMO's current rate case filing and its claims for costs. GMO's calculated average variable costs (Schedule MEM-5 to the Direct Testimony of Marisol Miller) are between 2.4¢ and 2.6¢/kWh, depending on voltage level. The energy charges in the high load factor block of GMO's current LGS and LPS tariffs are considerably higher, as previously noted. Since GMO proposes an essentially equal percentage increase to collect its requested revenue increase, these relationships would be perpetuated.

Q **WHAT DO YOU CONCLUDE FROM THIS REVIEW?**

A Based on the level of the average variable costs and also the avoided energy costs, it is clear that the off-peak energy charges are collecting more costs than appropriate.

Q WHAT SHOULD BE THE LEVEL OF THE OFF-PEAK ENERGY CHARGE?

A Recognizing that most of the fixed costs should be collected from use during the on-peak period and that consumption in the high load factor block occurs mostly during evening and weekend periods when GMO's energy costs would be lower than they are during the on-peak periods, it is reasonable that the high load factor energy block be at a level approximating the utility's average variable costs.

This structure would collect more costs through demand charges and provide better price signals to customers. It would also be a more equitable rate because it will charge high load factor and low load factor customers more appropriately. This structure also would improve the stability of GMO's earnings. Because customer demands are generally more stable than their energy purchases, this rate design would make GMO's revenue collection and earnings less volatile.

Q HOW DO YOU PROPOSE TO ADJUST THE LGS AND LPS RATES IN THIS CASE?

A The appropriate method depends on whether the rate schedule revenues are increasing or decreasing.

<u>If Rate Schedule Revenue is Increasing</u>

In the interest of gradualism, my proposal is to maintain the energy charges for the high load factor (over 360 hours use per month, or over a 50% load factor) block at their current levels, increase the middle blocks (hours use from 181 to 360) by three quarters of the average percentage increase, and to collect the balance of the revenue requirement for the tariff by applying a uniform percentage increase to the remaining charges in the tariff. This includes the customer charge, the reactive demand charge, the facilities charges, the demand charges and the initial block energy charges.

If Rate Schedule Revenue is Decreasing

If rate schedule revenue is decreasing, I would decrease the high load factor block of each voltage level by a uniform amount per kilowatthour equal to the total revenue decrease for the rate schedule by the total number of kilowatthours sold under the rate schedule.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

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

A Maurice Brubaker. My business 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, finance, 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.

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.

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

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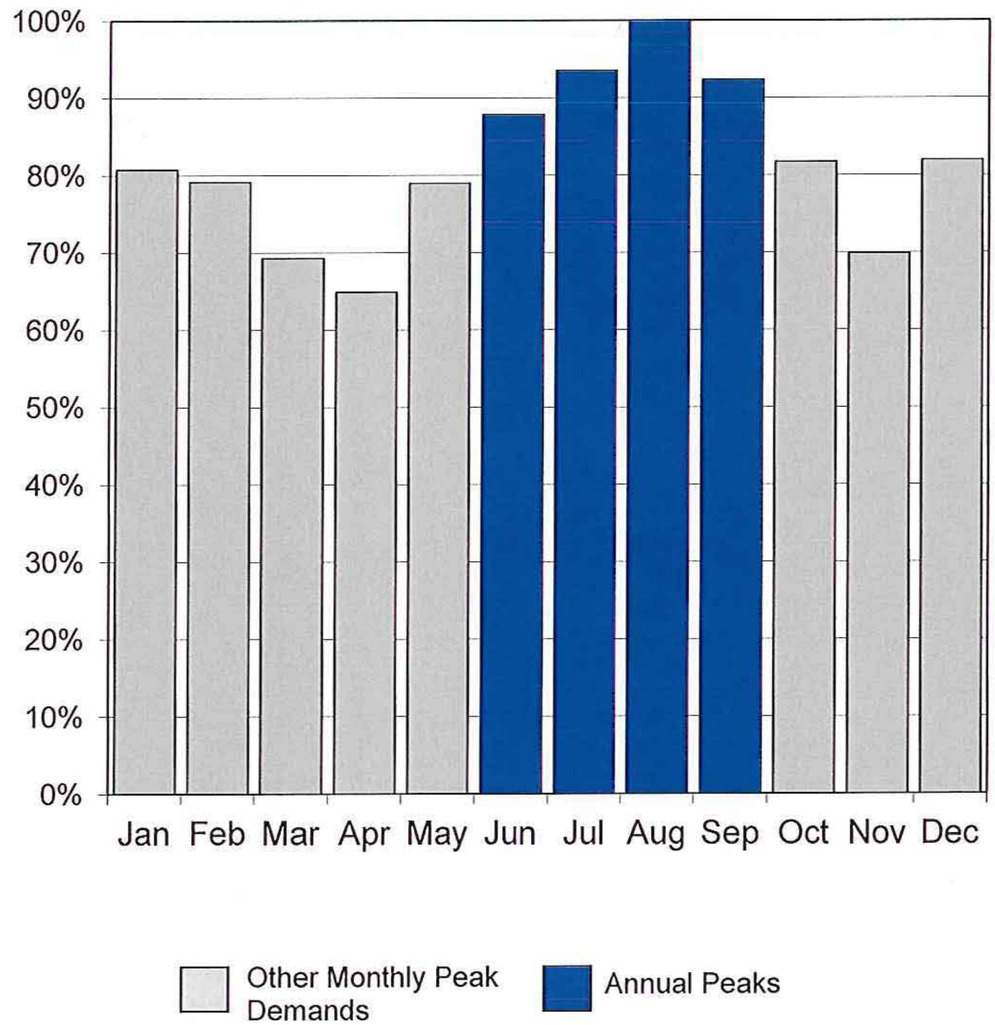
KCP&L GREATER MISSOURI OPERATIONS COMPANY
Case No. ER-2018-0146

Analysis of KCP&L GMO's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended June 30, 2017



KCP&L GREATER MISSOURI OPERATIONS COMPANY

Case No. ER-2018-0146

Analysis of KCP&L GMO's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended June 30, 2017

Line	Description	Total Company MW (1)	Percent (2)
1	January	1,493	80.8%
2	February	1,463	79.1%
3	March	1,281	69.3%
4	April	1,200	64.9%
5	May	1,460	79.0%
6	June	1,624	87.8%
7	July	1,729	93.5%
8	August	1,849	100.0%
9	September	1,706	92.3%
10	October	1,511	81.7%
11	November	1,292	69.9%
12	December	1,515	82.0%

Source: WN GMO Consolidated Allocators Rev 12-14-17 Avg-Excess 4CP

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Vertically Integrated Midwest Utilities
Industrial Power Cost (50 MW/68% LF) - 2017

Line	Utility	State	¢/kWh	Ranking
1	Madison Gas & Electric Company	Wisconsin	9.52	1
2	Entergy New Orleans, Inc.	Louisiana	9.09	2
3	We Energies (formerly Wisconsin Electric)	Wisconsin	8.90	3
4	Kansas City Power & Light Company	Kansas	8.62	4
5	Montana-Dakota Utilities Company	North Dakota	8.49	5
6	Kansas City Power & Light Company	Missouri	8.49	6
7	Northwestern Wisconsin Electric Company	Wisconsin	8.43	7
8	Northern States Power Company	Minnesota	8.38	8
9	Northern States Power Company	South Dakota	7.95	9
10	Otter Tail Power Company	Minnesota	7.93	10
11	Empire District Electric Company	Missouri	7.89	11
12	Northern States Power Company	North Dakota	7.78	12
13	Minnesota Power Company	Minnesota	7.78	13
14	CLECO Power LLC	Louisiana	7.75	14
15	Northern States Power Company	Wisconsin	7.48	15
16	WP&L	Wisconsin	7.36	16
17	Westar Energy-KGE	Kansas	7.25	17
18	Westar Energy-KPL	Kansas	7.25	18
19	Montana-Dakota Utilities Company	South Dakota	7.12	19
20	Otter Tail Power Company	North Dakota	6.89	20
21	Northwestern Energy	South Dakota	6.88	21
22	Wisconsin Public Service Corporation	Wisconsin	6.83	22
23	Empire District Electric Company	Arkansas	6.81	23
24	Interstate Power & Light	Iowa	6.57	24
25	Entergy Louisiana, Inc.	Louisiana	6.50	25
26	Superior Water, Light & Power Company	Wisconsin	6.50	26
27	**Kansas City Power & Light - GMO**	**Missouri**	**6.46**	27
28	Ameren Missouri	Missouri	6.22	28
29	Otter Tail Power Company	South Dakota	6.21	29
30	Empire District Electric Company	Kansas	6.09	30
31	Empire District Electric Company	Oklahoma	6.06	31
32	Black Hills Power, Inc. d/b/a Black Hills Energy	South Dakota	5.86	32
33	Entergy Arkansas, Inc.	Arkansas	5.85	33
34	Southwestern Electric Power Company	Louisiana	5.63	34
35	OG&E Electric Services	Arkansas	5.60	35
36	Entergy Louisiana, LLC (formerly Entergy Gulf States, Inc.)	Louisiana	5.40	36
37	Southwestern Electric Power Company	Arkansas	5.34	37
38	MidAmerican Energy	Iowa	4.79	38
39	Public Service Company of Oklahoma	Oklahoma	4.20	39
40	OG&E Electric Services	Oklahoma	3.76	40
41	MidAmerican Energy	South Dakota	3.32	41

Source: EEI Typical Bills and Average Rates Report

Notes:

- MidAmerican Energy Iowa Rates are calculated as the average of East, North, and South System
- Weighting = 4 months 2017 summer rate and 8 months 2017 winter rate

KCP&L GREATER MISSOURI OPERATIONS COMPANY
2018 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 6/30/2017

LINE NO.	DESCRIPTION	MISSOURI RETAIL (1)	RESIDENTIAL (2)	GEN. SERVICE (3)	LARGE GEN. SERVICE (4)	LARGE PWR SERVICE (5)	GENERAL TOD SERVICE (6)	THERMAL SERVICE (7)	LIGHTING (8)
0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE								
0020									
0030	OPERATING REVENUE								
0040	RETAIL SALES REVENUE	739,293,032	380,547,793	98,276,013	115,987,834	130,321,978	35,256	529,781	13,594,378
0050	OTHER SALES REVENUE (447)	119,157,171	51,222,934	13,923,143	22,512,208	30,407,855	5,645	122,648	962,738
0060	OTHER SALES REVENUE (449)	465,487	294,467	50,864	53,459	38,922	14	262	27,499
0070	OTHER OPERATING REVENUE	19,062,683	9,862,664	2,126,877	3,286,012	3,566,425	831	14,566	205,309
0080	TOTAL OPERATING REVENUE	877,978,372	441,927,857	114,376,897	141,839,513	164,335,180	41,747	667,257	14,789,923
0090									
0100	OPERATING EXPENSES								
0110	FUEL	80,650,017	34,905,908	9,421,356	15,153,731	20,439,682	3,852	84,755	640,733
0120	PURCHASED POWER	238,554,773	102,551,635	27,874,232	45,069,466	60,875,198	11,302	245,536	1,927,405
0130	OTHER OPERATION & MAINTENANCE EXPENSES	244,646,695	148,138,059	26,199,798	32,976,478	33,591,040	9,430	158,426	3,573,465
0140	DEPRECIATION EXPENSES (AFTER CLEARINGS)	95,918,984	55,578,690	10,231,935	13,682,192	12,737,037	3,648	65,420	3,620,063
0150	AMORTIZATION EXPENSES	7,352,566	4,029,690	758,986	1,242,722	1,282,439	340	6,074	32,316
0160	TAXES OTHER THAN INCOME TAXES	48,435,890	28,095,066	5,190,054	7,088,572	6,784,371	1,896	33,993	1,241,938
0170	FEDERAL AND STATE INCOME TAXES	30,583,283	11,379,836	7,662,792	5,044,761	5,576,565	2,415	10,249	906,664
0180	TOTAL ELECTRIC OPERATING EXPENSES	746,142,208	384,678,884	87,339,152	120,257,922	141,286,331	32,882	604,453	11,942,584
0190									
0200	NET ELECTRIC OPERATING INCOME	131,836,165	57,248,972	27,037,745	21,581,591	23,048,849	8,864	62,804	2,847,339
0210									
0220	RATE BASE								
0230	TOTAL ELECTRIC PLANT	3,655,504,019	2,103,868,053	391,994,446	542,109,703	515,187,641	144,051	2,593,784	99,606,343
0240	LESS: ACCUM. PROV. FOR DEPREC	1,328,020,451	773,723,135	142,514,938	191,323,002	178,331,038	50,849	912,559	41,164,930
0250	NET PLANT	2,327,483,568	1,330,144,918	249,479,508	350,786,701	336,856,602	93,201	1,681,225	58,441,413
0260	PLUS:								
0270	CASH WORKING CAPITAL	(52,906,934)	(28,715,464)	(6,144,608)	(8,178,667)	(8,747,172)	(2,266)	(39,493)	(1,079,265)
0280	MATERIALS & SUPPLIES	43,924,115	25,279,836	4,710,160	6,513,928	6,190,435	1,731	31,167	1,196,858
0290	EMISSION ALLOWANCES	237,349	102,726	27,727	44,597	60,153	11	249	1,886
0300	PREPAYMENTS	2,314,089	1,331,837	248,149	343,178	326,136	91	1,642	63,055
0310	FUEL INVENTORY	25,944,916	11,229,146	3,030,828	4,874,919	6,575,396	1,239	27,266	206,122
0320	DEFERRAL OF DSM/EE COSTS	6,712,507	3,410,788	752,214	1,186,657	1,305,944	298	5,195	51,412
0330	REGULATORY ASSETS	38,443,185	22,405,919	4,051,737	5,722,732	5,910,890	1,586	27,819	322,501
0340	LESS:								
0350	CUSTOMER ADVANCES FOR CONSTRUCTION	5,075,955	3,211,048	554,654	582,954	424,429	153	2,856	299,861
0360	CUSTOMER DEPOSITS	7,182,331	6,324,714	802,445	50,968	4,137	45	22	0
0370	TOTAL ACCUMULATED DEFERRED TAXES	472,013,338	271,659,880	50,615,895	69,999,379	66,523,094	18,600	334,920	12,861,570
0380	TOTAL RATE BASE	1,907,881,169	1,083,994,065	204,182,720	290,660,744	281,526,725	77,093	1,397,272	46,042,550
0390									
0400	RATE OF RETURN	6.910%	5.281%	13.242%	7.425%	8.187%	11.498%	4.495%	6.184%
0410	RELATIVE RATE OF RETURN	1.00	0.76	1.92	1.07	1.18	1.66	0.65	0.89

KCP&L GREATER MISSOURI OPERATIONS COMPANY
Case No. ER-2018-0146

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to
Cost of Service at Present Rates
($ in Thousands)

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 380,548	$ 1,083,994	$ 57,249	5.281%	76	$ 74,905	$ 17,656	$ 23,683	6.2%
2	General Service	98,276	204,183	$ 27,038	13.242%	192	14,109	(12,929)	(17,342)	-17.6%
3	Large General Service	115,988	290,661	$ 21,582	7.425%	107	20,085	(1,497)	(2,008)	-1.7%
4	Large Power Service	130,322	281,527	$ 23,049	8.187%	118	19,454	(3,595)	(4,822)	-3.7%
5	General TOD Service	35	77	$ 9	11.498%	166	5	(4)	(5)	-13.5%
6	Thermal Service	530	1,397	$ 63	4.495%	65	97	34	45	8.5%
7	Total Lighting	13,594	46,043	$ 2,847	6.184%	89	3,182	334	448	3.3%
8	Total	$ 739,293	$ 1,907,881	$ 131,836	6.910%	100	$ 131,836	$ (0)	$ (0)	0.0%

Source: Schedule MEB-COS-3

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Case No. ER-2018-0146

Cost of Service Adjustments for
50% Movement Toward
Cost of Service 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 Increase in Current Revenue (4)
1	Residential	$ 380.5	$ 11.8	$ 392.4	3.1 %
2	General Service	98.3	(8.7)	89.6	(8.8)%
3	Large General Service	116.0	(1.0)	115.0	(0.9)%
4	Large Power Service	130.3	(2.4)	127.9	(1.9)%
5	General TOD Service	0.0	(0.0)	0.0	(6.7)%
6	Thermal Service	0.5	0.0	0.6	4.3 %
7	Total Lighting	13.6	0.2	13.8	1.6 %
8	Total	$ 739.3	$ -	$ 739.3	0.0 %

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-4, times 50%.

KCP&L GREATER MISSOURI OPERATIONS COMPANY
Case No. ER-2018-0146

Cost of Service Adjustments for
25% Movement Toward
Cost of Service at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 25% Toward Cost Of Service[1] (2)	Adjusted Current Revenue (3)	Revenue-neutral Percent Increase in Current Revenue (4)
1	Residential	$ 380.5	$ 5.9	$ 386.5	1.6 %
2	General Service	98.3	(4.3)	93.9	(4.4)%
3	Large General Service	116.0	(0.5)	115.5	(0.4)%
4	Large Power Service	130.3	(1.2)	129.1	(0.9)%
5	General TOD Service	0.0	(0.0)	0.0	(3.4)%
6	Thermal Service	0.5	0.0	0.5	2.1 %
7	Total Lighting	13.6	0.1	13.7	0.8 %
8	Total	$ 739.3	$ -	$ 739.3	0.0 %

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-4, times 25%.