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BY HAND DELIVERY

February 5, 2007

Cully Dale
Secretary/Chief Administrative Law Judge
Missouri Public Service Commission
200 Madison Street
Jefferson City, MO 65101

FILED[3]
FEB 5 2007
Missouri Public Service Commission

RE: Case No. ER-2007-0002

Dear Judge Dale:

Attached for filing on behalf of the Missouri Industrial Energy Consumers are an original and eight (8) copies of the Rebuttal Testimony of Maurice Brubaker in the above-referenced case.

Thank you for your assistance in bringing this filing to the attention of the Commission.

Very truly yours,

Diana Vuylsteke

Diana M. Vuylsteke
DMV:ln

Attachments
cc: All Parties

Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Issues:	Cost of Service
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2007-0002

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	Case No. ER-2007-0002

Rebuttal Testimony and Schedules of

Maurice Brubaker

on Cost of Service

FILED 3

FEB 5 2007

Missouri Public Service Commission

On Behalf of

Missouri Industrial Energy Consumers

February 5, 2007
Project 8632

BAI

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	Case No. ER-2007-0002

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

Affidavit of Maurice Brubaker

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

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

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony on cost of service which was prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2007-0002.

3. I hereby swear and affirm that the testimony is true and correct and that it shows the matters and things that it purports to show.

M E Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 5th day of February, 2007.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2008

Carol Schulz
Notary Public

My Commission Expires February 26, 2008.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	Case No. ER-2007-0002

Rebuttal Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q ARE YOU THE SAME MAURICE BRUBAKER WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A Yes. I have previously filed direct testimony on revenue requirement, cost of service and fuel adjustment issues.

Q ARE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN ANY OF THOSE PRIOR TESTIMONIES?

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

INTRODUCTION AND SUMMARY

Q ON WHOSE BEHALF ARE YOU PRESENTING THIS REBUTTAL TESTIMONY?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers (MIEC).

Q HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESS DAVID ROOS, OPC WITNESS BARBARA MEISENHEIMER AND AARP WITNESS RONALD BINZ ON THE SUBJECT OF CLASS COST OF SERVICE?

A Yes.

Q DO YOU HAVE REBUTTAL TO THE POSITIONS OF THESE WITNESSES?

A Yes, I do. I disagree with the methods which these witnesses have used for the allocation of production and transmission fixed costs and with respect to the allocation of certain other components of the cost of service. The allocation of the generation and transmission fixed costs is the largest and most important of these issues, and I will address it first. The allocation of revenues from off-system sales is the second most critical issue and I address it next. Then, I will address some of the other differences in the allocations.

Q HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESS JAMES BUSCH?

A Yes, I have. Mr. Busch proposes a revenue realignment based on the results of Staff's class cost of service study performed by Mr. Roos.

Q DO YOU HAVE ANY RESPONSE TO MR. BUSCH'S RECOMMENDATIONS?

A Yes. Mr. Busch's recommendations are based on the faulty class cost of service (CCOS) study performed by Staff Witness Roos. If this study were corrected, and Mr. Busch's methodology applied, a more appropriate realignment of class revenues would occur.

Q DO YOU HAVE ANY RESPONSE TO THE REVENUE ALLOCATIONS PROPOSED BY OTHER PARTIES?

A Yes. In each case, the recommendation is based on a faulty cost of service study. Because the recommendations are based on studies which do not reasonably reflect cost of service, these revenue allocation recommendations should be rejected.

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My rebuttal testimony may be summarized as follows:

1. The Average & Peak (A&P) allocation methods applied by Staff, OPC and AARP are not explained as to methodology, supported as to theory or shown to be applicable to the AmerenUE system. These studies significantly over-allocate costs to large high load factor customers such as those that take service on the Large Power rate.

2. The study which OPC calls "time-of-use (TOU)" is not explained as to methodology, supported as to theory or shown to be applicable to the AmerenUE system, and allocates fixed costs even more disproportionately (than the A&P studies) to large high load factor customers such as those that take service on the Large Power rate.

3. Neither the A&P method used by Staff nor the "TOU"" method advanced as an alternative by OPC are traditional, none are used in any other jurisdiction, and none have ever even been adopted by the Missouri PSC.

4. The Staff, OPC and AARP cost of service studies are internally inconsistent in that they allocate above average generation capacity costs to high load factor customers, but do not give them the benefit of the lower energy-related costs that correspond to the above average capital cost allocation.

5. The Average & Excess - 3 NCP study that I offered in my direct testimony is the most appropriate allocation method for the AmerenUE system and is the one that should be adopted by the Commission and used as a guide to distribute any revenue increase or decrease found appropriate.

6. In addition to the problems noted above, the OPC A&P CCOS study:

   a. Uses an incorrect (too high) load factor to weight the energy component of the A&P allocator.

   b. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   c. Fails to recognize any customer-related component in the primary distribution system.

7. In addition to the above problems, OPC's "TOU" allocation CCOS study:

   a. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   b. Fails to recognize any customer-related component in the primary distribution system.

8. In addition to problems noted above, Staff's study:

   a. Uses an unreasonably low weighting for summer peak demands (19%), compared to other demands (81%).

   b. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   c. Allocates a significant amount of demand-related production function non-fuel operation and maintenance expense on energy.

9. In addition to problems noted above, AARP's study:

   a. Allocates transmission costs using 12 monthly coincident peaks.

   b. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   c. Fails to recognize any customer-related component in the primary distribution system.

d. Allocates a significant amount of demand-related production function non-fuel operation and maintenance expense on energy.

ALLOCATION OF GENERATION AND TRANSMISSION CAPACITY COSTS

Q WHAT IS DISCUSSED IN THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A I discuss the allocation of generation and transmission capacity costs.

Staff Study

Q WHAT METHOD HAS STAFF USED FOR THE ALLOCATION OF GENERATION AND TRANSMISSION DEMAND-RELATED COSTS?

A Staff has used an A&P allocation method. In particular, Staff uses the 12 monthly non-coincident peak demands of each customer class along with each class's annual energy consumption. The energy component is weighted equal to the system's annual load factor.

Q DOES STAFF EXPLAIN THE BASIS FOR SELECTING THIS ALLOCATION METHODOLOGY?

A No. Staff neither explains the derivation of the particular allocation factors, nor does it explain or attempt to justify why this particular method is appropriate for AmerenUE. Staff also does not explain why it is appropriate to use class peak demands from every month of the year rather than just from the summer months.

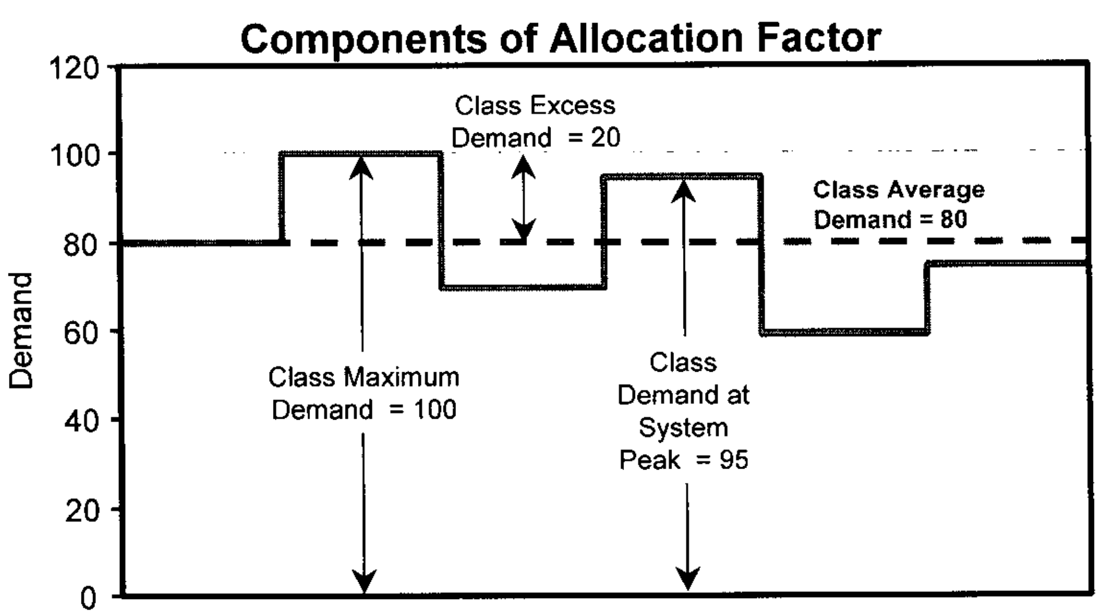
Furthermore, Staff determines its weighting of monthly class peak demands by using a methodology that is described in a 1983 article that it simply attaches to its testimony. In addition, Staff does not attempt to further explain the basis for the method, how the method works, or why it is appropriate to use in 2007 on the AmerenUE system.

Q HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE AVERAGE & EXCESS (A&E) METHODOLOGY THAT YOU USED IN YOUR CCOS STUDY?

A The A&P allocator is constructed by multiplying each class' energy responsibility factor times the system load factor, and adding to that each class' percentage contribution to the annual system peak multiplied by the quantity one minus the load factor.

Both the A&P and A&E methods are two-step processes. In both methods, the first step is to weight the average demand by the system load factor. The second step is where the difference occurs. This is illustrated in Figure 1.

Figure 1



Q PLEASE REFER TO FIGURE 1 AND EXPLAIN THE DIFFERENCES.

A Figure 1 is a simplified representation of a class load. The maximum demand of this particular class is represented as 100. Its contribution at the time of the system peak is 95, its average demand is 80, and the excess demand (the difference between its peak demand and its average demand) is 20.

The A&E method combines the class average demand with the class excess demand in order to construct an allocation factor that reflects average use as well as the excess of each class' peak demand over its average demand. The A&P method, on the other hand, combines the average demand with the contribution to the system peak demand. As is evident from Figure 1, the average demand (80) is a component or sub-set of the contribution to system peak demand (95). Accordingly, when roughly equal weighting is given to the average demand and the contribution to system peak demand, the average demand is double counted. This is a serious error, and has the effect of allocating significantly more costs to high load factor customers than is appropriate.

Q IS THE A&P METHOD A REASONABLE ONE TO USE?

A No, it is not. As noted above, this allocation gives essentially equal weighting to annual energy consumption and the contribution to the system peaks used in the allocation of the investment in generation and transmission facilities. Since generation and transmission facilities must be designed to carry the peak loads imposed on them, the roughly equal weighting to energy consumption in the allocation factor is not related to cost of service at all.

Unlike the A&E method, which considers class individual peaks and class load factors, as well as diversity between class peaks and system peak, the A&P method arbitrarily allocates about half of these costs on annual energy consumption.

Q HOW MUCH WEIGHTING DOES STAFF'S A&P ALLOCATION METHOD GIVE TO SUMMER DEMANDS?

A Staff uses class demands from all 12 months, regardless of their magnitude, and weights them. Although not explained in the testimony, the information presented in the workpapers of Mr. Roos shows that the peak demands occurring during the three summer (June - August) peak months have a weighting of **less than 19%** in his A&P allocation factor. That means that loads at other times are weighted 81%, or over four times as much.

Q IS THIS WEIGHTING FOR SUMMER PEAK DEMANDS A REASONABLE ONE?

A No. This low weighting is fundamentally unreasonable. It is summer peak demands that drive the need for the addition of generation capacity and an allocation methodology which gives only 19% weighting to those summer peak demands cannot be regarded as reasonable. Staff's allocations skew the results so that high load factor customers are allocated a significant amount of costs that they are not responsible for causing.

Q WHAT METHODOLOGY DID STAFF ADVOCATE FOR JURISDICTIONAL DEMAND ALLOCATION IN THE RECENT KANSAS CITY POWER & LIGHT COMPANY (KCPL) RATE CASE, CASE NO. ER-2006-0314?

A In that case, KCPL had proposed a 12 monthly coincident peak allocation methodology for dividing costs between the Kansas retail jurisdiction, the resale jurisdiction and the Missouri retail jurisdiction. Staff witnesses presented extensive testimony demonstrating why summer peak demands were more important than demands in other months, and advocated a method which used only demands imposed on the system during the summer months.

Q DO KCPL AND AMERENUE HAVE A SIMILAR LOAD PATTERN?

A Yes. This is displayed graphically on Schedule MEB-COS-R-1. Clearly, the load patterns are quite similar, with dominant summer loads. Use of summer peak demands in the allocation is clearly as appropriate in the case of AmerenUE as it was in the case of KCPL.

Q ISN'T IT TRUE THAT THE STAFF'S ARGUMENTS IN THE KCPL CASE WERE IN THE CONTEXT OF JURISDICTIONAL, AND NOT CLASS, ALLOCATIONS?

A Yes. The issue arose first in the context of revenue requirements, i.e., when considering allocation of costs among jurisdictions. However, the same principles that compel the use of summer peak demands for jurisdictional allocation compel the same methodology when allocating among customer classes.

In fact, an appropriate identification of cost-causing peaks is even more important at the class level than at the jurisdictional level because the differences between retail customer class load patterns are much greater than the differences between jurisdictional load patterns. Accordingly, a failure to appropriately distinguish these load characteristics at the class level would introduce even more distortions into the results than is true when the regulatory jurisdictions are viewed in total and compared one with another.

Q IS THERE PRECEDENT TO SUPPORT THE STAFF'S WEIGHTED 12 NCP A&P ALLOCATION METHOD?

A No. This became evident in the Aquila class cost of service case, Case No. EO-2002-384. The method which Staff uses in this (AmerenUE) case is the same as the method which OPC used in the Aquila case. In response to a data request in the Aquila case, OPC acknowledged that this particular methodology (weighted 12 NCP A&P) was not used anywhere to the best of its knowledge. I would concur with that conclusion.

OPC Studies

Q WHAT METHOD DID OPC USE FOR ALLOCATING GENERATION AND TRANSMISSION CAPACITY COSTS?

A OPC used a 3-month CP A&P allocator and also presented what it calls a "TOU" method.

Q DOES MS. MEISENHEIMER SUPPORT OR EXPLAIN WHY SHE BELIEVES THE PARTICULAR METHODOLOGIES WHICH SHE HAS CHOSEN ARE APPROPRIATE?

A In regard to her A&P study she does not provide any explanation or supporting reason for why the use of this method is appropriate. To support the use of her

"TOU" study she provides a brief description of the Probability of Dispatch Method from the NARUC manual and claims that this method is consistent with her "TOU" study. However, she doe not explain how her "TOU" study and the Probability of Dispatch method are correlated.

Furthermore, she just calls her second study a "TOU" study but provides absolutely no description of the basis for the derivation of the allocation factors, the logic or theory supporting the use of this particular allocation method, or its applicability to the AmerenUE system. To simply call something a "TOU Study" is not meaningful because there is no conventional methodology or understanding that can be associated with the description: a "TOU Study."

Q HAS A VERSION OF MS. MEISENHEIMER'S PROPOSED "TOU" STUDY EVER BEEN ADOPTED IN ANY OTHER JURISDICTION?

A No. This method is conceptually similar to the method that was advanced by Commission Staff in the Aquila class cost of service case, Case No. E0-2002-384. In that case, Staff admitted that this methodology had not been used in any other state and, in fact, **has not ever** been adopted, even in Missouri.

This puts the "TOU" study in the same category as Staff's study, which also have no precedent to support it and certainly no acceptance in the industry.

Q TO DEVELOP THE WEIGHTING FOR THE DEMAND COMPONENT AND THE ENERGY COMPONENT OF OPC'S A&P ALLOCATION FACTOR, WHAT LOAD FACTOR DID OPC USE?

A OPC used a 56.54% load factor. OPC's method of developing the system load factor produced a higher system load factor than what the Company produced.

Q DID OPC USE ANNUAL PEAK TO DEVELOP ITS LOAD FACTOR?

A No. The load factor which OPC has developed is erroneous. According to OPC's worksheet, the annual peak used is an average of the three system peak months. This method of calculating the demand number which OPC uses to calculate the load factor is approximately 220 megawatts (MW) below the total company peak. This is an error. The system annual load factor is approximately 55.06%, not 56.54%.

This error overstates the load factor, thereby overstating the energy component of the A&P allocation factor. Thus, even if one were to accept OPC's method, the allocation factors are wrong. This, too, results in an over-allocation of costs to large high load factor customers such as those served under the Large Power rate.

Q DOES MS. MEISENHEIMER EXPLAIN HOW SHE ALLOCATES CAPACITY AND ENERGY COSTS IN THE "TOU" STUDY?

A No, she does not. However, a review of her workpapers indicates that an hourly assignment of capacity costs of generation plants was made. It appears that a capacity component was identified for each plant. Then, a production dispatch model was run to determine the output of each plant during each hour of the year. The dispatch level (output) of each plant, for each hour, was then totaled and divided into the identified capacity component. This per unit capacity component was then multiplied times the output of each plant in each hour in order to allocate capacity costs to each hour that a plant ran. This was repeated for each plant and a total capacity cost was developed for each hour. These hourly capacity costs were then allocated to customer classes based on class loads in each hour.

Q HAVE YOU BEEN ABLE TO ANALYZE THE RESULTS OF OPC'S CAPACITY COST ASSIGNMENT TO HOURS?

A Yes. Please refer to Schedule MEB COS-R-2 attached to this testimony.

Q PLEASE EXPLAIN THIS GRAPH.

A This graph shows an hourly profile of the results of OPC's TOU capacity cost assignment. The average hourly load is represented by the blue line with the large squares. Each point on this chart for the load (left scale) is equal to the sum of the loads in each identified hour (i.e., 1:00 a.m., 2:00 a.m., etc.) of each day, divided by 365 days. Accordingly, this represents an average daily load profile.

The capacity charge line (red with pyramids) was created in a similar fashion. It shows the hourly assignment of capacity costs under OPC's approach. Note that the capacity cost per hour (right scale) in the middle of the night (2:00 a.m. - 5:00 a.m.), when demand is at its lowest is almost as high as the capacity cost in late afternoon (2:00 p.m. - 5:00 p.m.), when the peak is occurring. Given this profile of capacity cost assignments, OPC's "TOU" method cannot be described as cost-causation at all. There is no reasonable basis to believe that loads in the middle of the night cause installation of generation capacity. Rather, it is the peak loads occurring during the day, especially the highest ones that occur in the summer, that drive the need for capacity additions.

Rather than being "cost-causation," OPC's "TOU" allocation methodology is an <u>assignment</u> method which puts the same per kilowatt (kW) capacity cost of a generation facility into every hour of the year that it runs.

Q HAS STAFF PREVIOUSLY CHARACTERIZED THIS TYPE OF COST ALLOCATION METHODOLOGY?

A Yes. It actually originated with Staff, and a form of it has been adopted by OPC. In the previously mentioned Aquila class cost of service case, Case No. EO-2002-384, Staff witness James Watkins testified that the methodology was not cost-causation at all, but rather was something developed many years ago in an effort to have data that might be used in developing time-of-use rates. Stretching the methodology to allocate costs among customer classes extends it well beyond any reasonable use.

Q DO YOU TAKE ISSUE WITH REGARD TO HOW THE OPC ALLOCATES FUEL AND VARIABLE PURCHASED POWER COSTS TO INDIVIDUAL CUSTOMER CLASSES?

A Yes. The OPC allocates fuel-related costs to individual customer classes on the basis of their energy requirements at the **sales** level. Because of this, the OPC is ignoring the individual line losses of each customer class. This method of allocation inappropriately allocates a larger portion of fuel-related costs to customers who receive their service at the primary level, such as those customers served under the Large Power rate.

AARP Study

Q WHAT METHOD DID AARP USE FOR ALLOCATING GENERATION AND TRANSMISSION CAPACITY COSTS?

A AARP used a 4-month CP A&P allocator, somewhat similar to OPC.

Q DOES MR. BINZ SUPPORT OR EXPLAIN WHY HE BELIEVES THE PARTICULAR METHODOLOGY WHICH HE HAS CHOSEN IS APPROPRIATE?

A No. Mr. Binz does not provide any explanation or supporting reason for why the use of his method is appropriate in this proceeding. He simply states that there are more superior methods for allocating generation costs than the A&E method and indicates that based on his experience the use of the A&E method is declining in some state jurisdictions.

Q DOES MR. BINZ PROVIDE SUPPORT OR EVIDENCE FOR HIS STATEMENTS THAT THERE ARE MORE SUPERIOR METHODS TO THE A&E METHOD AND THAT THE USE OF THE A&E METHOD IS DECLINING IN STATE JURISDICTIONS?

A No. Mr. Binz does not provide any support or evidence backing these two statements. Based on my experience, the use of the A&E method has not been declining. In fact, in the state of Colorado, the same state where Mr. Binz served as Consumer Council, the A&E method has been accepted by the Commission for many years.

Q DOES MR. BINZ'S PROPOSED GENERATION COST ALLOCATOR CONTAIN THE SAME FLAW AS BOTH STAFF'S AND OPC'S?

A Yes. His proposed method gives a roughly equal weighting to annual energy consumption and contribution to system peak. Because of this, high load factor customers are allocated a significant amount of generation costs that they are not responsible for causing.

Q **HOW DID THE AARP ALLOCATE TRANSMISSION COSTS?**

A AARP allocated transmission costs in a similar fashion to the Company, that is they used the 12 monthly coincident peaks.

Q **WHAT IS THE PROBLEM WITH THIS FORM OF ALLOCATION FOR TRANSMISSION COSTS?**

A As stated in my direct testimony, the transmission system must be built to meet the system peak demands, which occur in the summer; not the average of the 12 monthly peak demands, many of which are significantly lower than the summer peak demands. In this respect, the transmission system is similar to the generation system, and should be allocated in a similar fashion.

Symmetry of Fuel and Capital Cost Allocation

Q **DO YOU HAVE ANY DISAGREEMENT WITH THE ALLOCATION OF FUEL AND VARIABLE PURCHASED POWER COSTS ON THE BASIS OF CLASS ENERGY REQUIREMENTS, ADJUSTED FOR LOSSES?**

A In the context of traditional studies like coincident peak and A&E, I do not. However, in the context of the non-traditional studies that Staff, OPC and AARP have offered, all of which heavily weight energy in the allocation of fixed or demand-related generation costs, it is not appropriate.

Q PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO ALLOCATE ENERGY COSTS IN THIS FASHION WHEN USING STUDIES SUCH AS THOSE ADVANCED BY STAFF, OPC AND AARP?

A All three of these studies allocate significantly more generation fixed costs to high load factor customers than do the traditional studies. In other words, the higher the load factor of a class, the larger the share of the generation fixed costs that gets allocated to the class. If the costs allocated to classes under these methods were divided by the contribution of these classes to the system peak demand, or by the A&E demand, the result is a higher capital cost per kW for the higher load factor classes, and a lower capital cost per kW for the low load factor classes. Effectively, this means that the high load factor classes have been allocated an above average share of capital cost for generation, and the low load factor customer classes have been allocated a below average share.

Given these allocations of capital cost, it would be inappropriate to use the same fuel costs for all classes. Rather, the fuel cost allocation should recognize that the higher load factor customer classes should receive below average fuel cost to correspond to the above-average capital cost (similar to base load units) allocated to them, and the lower load factor classes should get an allocation of fuel costs that is above the average, corresponding to the lower than average capital cost (i.e., peaking units) allocated to them.

Q WHY WOULD IT BE APPROPRIATE TO RECOGNIZE A LOWER FUEL COST ALLOCATION TO THOSE CLASSES THAT ARE ALLOCATED A HIGHER CAPITAL COST?

A It is not only appropriate, but it is essential if the energy-weighted allocations of generation costs are employed. Failure to make this kind of distinction would give high load factor customers the worst of both worlds – above average capital costs and average energy costs; and the low load factor customers the best of both worlds – below average capital cost and average fuel cost.

Q HAVE YOU PREPARED ANY CALCULATIONS AND DEVELOPED A SCHEDULE TO ILLUSTRATE THIS?

A Yes, I have. Please refer to Schedule MEB-COS-R-3 attached to this testimony. This schedule compares the capacity costs per kW and the energy costs per kilowatthour (kWh) across classes for the traditional allocation method, Staff's A&P method, AARP's A&P method, OPC's A&P method and OPC's "TOU" method. To establish a common framework of costs for the analysis, so as to isolate the impacts just of allocation methodology, I used the total generation capacity costs and total generation energy costs from Staff's cost of service study (Case 3) and applied my allocation factors (traditional) as well as the Staff, OPC and AARP demand and energy allocators to these total amounts. I then divided the results by the A&E capacity kW and by the class megawatthours (MWh).

Q PLEASE EXPLAIN WHAT THIS SCHEDULE SHOWS.

A The first block of the schedule shows that under traditional allocation methods both the capacity costs per kW and the energy costs per kWh allocated to each class are the same. The second block shows the allocation results under Staff's A&P method. Note that the impact is to allocate significantly more capital costs, in fact, 24% more, to the Large Power class than under the traditional approaches, which allocate average capacity costs. Note also that fuel costs per kWh are the same for all classes.

The third and fourth blocks show similar class capacity allocation results for AARP's and OPC's A&P studies. Please note that OPC's study goes one step further and even allocates higher than average energy-related costs to the high load factor customers.

The final block shows the OPC "TOU" study. Predictably, an even heavier allocation of capacity costs is made to the Large Power class, and even less is allocated to the Residential class. Once again, the energy costs allocated to high load factor customers is above average.

Q YOU INDICATED THAT THE ENERGY COSTS PER KWH ARE NOT MEANINGFULLY DIFFERENT UNDER THESE ALLOCATIONS. HOW DIFFERENT ARE THE ENERGY COSTS OF THE DIFFERENT GENERATING FACILITIES?

A They are quite diverse. For example, the fuel cost for the Callaway nuclear unit is less than 0.5¢ per kWh, the base load coal plants have fuel costs in the range of 0.9¢ to 1.4¢ per kWh, and the peaking units have fuel costs over 10¢ per kWh. (Note: These fuel costs are taken from AmerenUE's 2005 FERC Form 1 report.) Obviously, if some classes are allocated higher capacity costs than others, they should be entitled to at least an above-average share of the energy output from the higher capital cost, more fuel efficient, base load type generating units, which would make their fuel cost per kWh larger than average. None of the allocation methods advanced by Staff, OPC and AARP recognize this correspondence, and as a result over-allocate costs to high load factor customers.

Q **WHAT DO YOU BELIEVE SCHEDULE MEB-COS-R-3 SHOWS?**

A I believe it clearly demonstrates that the A&P and the "TOU" methods that have been sponsored in this case by Staff, OPC and AARP are highly non-symmetrical. They allocate capacity costs differentially across customer classes as a function of load pattern, but do nothing to offset this higher allocation of capacity costs with a correspondingly lower allocation of energy costs. Thus, I believe these studies are further flawed for this reason and are entitled to no weight.

Q **HAS THIS ISSUE OF ALLOCATING A BELOW AVERAGE SHARE OF FUEL COSTS TO HIGHER LOAD FACTOR USERS RECENTLY BEEN ADDRESSED IN A MISSOURI RATE PROCEEDING?**

A Yes. Staff witness Lena Mantle addressed this topic in her September 8, 2006 rebuttal testimony in the recent KCPL rate case, Case No. ER-2006-0314. Her testimony discussed planning principles and the relationship between load factors and generation mix. Her testimony clearly demonstrates that as capital cost increases (with higher load factor), energy cost decreases. While her testimony was in the context of jurisdictional allocations, the principle is the same at the class level. In fact, the recognition of the principles at the class level is even more critical since the differences between class load factors are much greater than the differences between jurisdictional load factors.

Importance of Precedent

Q IN EARLIER TESTIMONY, YOU POINTED OUT THAT MANY OF THE STUDIES BEING PROPOSED BY OTHER PARTIES IN THIS PROCEEDING ARE NOT USED IN OTHER JURISDICTIONS AND ARE NOT SUPPORTED BY PRECEDENT OR ACCEPTANCE IN THE INDUSTRY. WHAT IS THE SIGNIFICANCE OF THE FACT THAT A METHODOLOGY IS NOT USED IN OTHER JURISDICTIONS?

A Cost of service studies for electric systems have been performed for well over 50 years. This means that there has been a significant amount of analysis that has gone into the question of determining how best to ascertain cost-causation on electric systems, across a broad spectrum of utility circumstances. Methods that have not had the benefit of that analysis and withstood the test of time must be viewed with skepticism, and proponents of such methods bear a special burden of proving that they do a more accurate job of identifying cost-causation than do recognized methods, and are not merely ad hoc creations designed simply to support a particular result desired by the analyst.

ALLOCATION OF REVENUE FROM OFF-SYSTEM SALES OF ENERGY

Q DID STAFF, OPC AND AARP ALLOCATE REVENUE FROM OFF-SYSTEM SALES IN A MANNER SIMILAR TO THAT OF THE COMPANY?

A Yes. All three parties mentioned above used the same inconsistent allocation of off-system sales as the Company did. That is, they all used the energy allocator to allocate to individual customer classes the costs of the fuel and variable purchased power that is incurred to support off-system sales. They then allocate all of the revenues derived from the off-system sales to the customer classes based on the production demand allocation factor. As explained in my direct testimony, this inconsistency in the allocation of the costs and the revenues significantly under-allocates off-system sales revenue credits to high load factor customer classes. Having allocated 100% of the expenses on an energy basis, a consistent approach would be to also allocate 100% of the revenues on an energy basis.

Q YOU INDICATED IN YOUR DIRECT TESTIMONY THAT IN THE RECENT KCPL RATE CASE, CASE NO. ER-2006-0314, THE COMMISSION ADOPTED THE APPROACH OF ALLOCATING REVENUES FROM OFF-SYSTEM SALES ON THE BASIS OF AN ENERGY ALLOCATOR. IN THAT PROCEEDING, HOW DID STAFF, OPC & AARP PROPOSE TO ALLOCATE REVENUE FROM OFF-SYSTEM SALES?

A AARP did not perform a cost of service analysis in the KCPL proceeding. Both Staff and the OPC supported the use of an energy allocator to allocate revenues from off-system sales. In fact, on page 38 of the KCPL Final Report and Order, Staff was quoted as saying that the use of the energy allocator to allocate off-system sales revenues "is the time-tested and widely accepted method for allocating such revenues in the state" of Missouri.

Q HAVE YOU EVALUATED THE IMPACT OF ADJUSTING STAFF'S COST OF SERVICE STUDY BY ALLOCATING OFF-SYSTEM SALES REVENUES ON AN ENERGY BASIS, AS OPPOSED TO A DEMAND BASIS?

A Yes, I have. Staff's Case 3 CCOS indicated that the Large Power class had a revenue deficiency of $9.1 million. Schedule MEB-COS-R-4 shows the results of correcting Staff's study to eliminate this inconsistency. This schedule indicates that after substituting the methodology for allocating off-system sales revenues that Staff argued for in the KCPL case, the Large Power class actually has a revenue deficiency of $(5.4) million, or, in other words, a surplus of $5.4 million. This difference of $14.5 million shows the tremendous impact, to high load factor customers, of using such an inconsistent treatment for allocating off-system sales revenues.

OTHER PROBLEMS IN STUDIES

Q WHAT WILL YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A I will address certain other problems, inconsistencies and/or errors that we have identified in Staff's, OPC's and AARP's cost allocation studies, that I have not previously addressed.

Allocation of Non-Fuel Production O&M Expense

Q DID STAFF AND THE AARP MAKE THE SAME ERROR AS THE COMPANY DID WITH RESPECT TO THE ALLOCATION OF CERTAIN NON-FUEL PRODUCTION O&M EXPENSES?

A Yes. Because Staff and the AARP followed the same methodology as the Company, they designated a substantial portion of production function non-fuel operation and maintenance-related expenses as variable. As indicated in my direct testimony, it is more conventional to allocate these costs on an "expense follows plant" basis, that is to say, on a demand basis. The vast majority of these costs do not vary in any appreciable way with the number of kWhs generated, but occur as a function of operation and passage of time. OPC used the approach I used, but Staff and AARP did not.

Allocation of Certain Distribution Costs

Q WHAT IS THE LARGEST DIFFERENCE AMONG THE PARTIES WITH RESPECT TO THE ALLOCATION OF COSTS IN THE DISTRIBUTION ACCOUNTS?

A The largest difference among the parties is the issue of whether or not there is a customer component to the primary portion of the distribution system, namely Account 364 (Poles, Towers and Fixtures), Account 365 (Overhead Conductors and Devices), Account 366 (Underground Conduit) and Account 367 (Underground Conductors and Devices). AmerenUE, Staff and I all recognize the existence of a customer component in the primary portion of these accounts while OPC and AARP do not.

Q WHAT IS THE GENERALLY ACCEPTED PRACTICE?

A The generally accepted industry practice is to recognize the customer component in the primary distribution system. The text and diagram at page 12 of my direct testimony generally show the nature of the distribution system and explain why there is a customer component. Briefly, the more geographically dispersed the customers are, and the more of them that there are, the greater the extent of the primary distribution network needed to provide service. It takes much more primary network to serve 10,000 customers that each have a 10 kW load than it does to serve 20 customers that each have a 5,000 kW load.

Q DOES OPC EXPLAIN THE BASIS FOR IGNORING THE ALLOCATION OF DISTRIBUTION COSTS TO THE CUSTOMER COMPONENT?

A No. The only statement I can find is two sentences on page 8 of Ms. Meisenheimer's direct testimony. That language is:

> "For example, with the exception of service drops and meters, most of the facilities between the utility customer's point-of-service and the distribution substation are shared facilities. Since no portion of such facilities are directly related to the number of customers, the associated costs are best classified as demand-related, rather than customer-related."

Q DOES AARP EXPLAIN THE BASIS FOR IGNORING THE ALLOCATION OF DISTRIBUTION COSTS TO THE CUSTOMER COMPONENT?

A Yes. AARP's largest criticism of assigning part of distribution costs to the customer component has to do with what they allege are errors in the zero-intercept and minimum system equations. Mr. Binz feels these two methods (zero-intercept and minimum system) for allocating distribution costs between a customer and demand component are purely based on a mathematical abstraction and hence are fictional.

Q DO THESE STATEMENTS PROVIDE A RATIONALE FOR IGNORING A CUSTOMER COMPONENT IN THE PRIMARY DISTRIBUTION SYSTEM?

A No. While it is true that many of these facilities are shared, in the sense that they are used to provide service to many customers, that says nothing about whether there is a customer component. The conclusion in the second sentence above (from Ms. Meisenheimer's testimony) simply does not follow from the previous assertions, and does not support the treatment that OPC and AARP gave to the primary distribution system.

Q DO AMERENUE'S STUDIES ASSIGN A LARGE PERCENTAGE OF THE DISTRIBUTION SYSTEM COSTS TO THE CUSTOMER COMPONENT?

A No. The other utilities in this state utilize a minimum system method, rather than the zero intercept method proposed by AmerenUE. The customer component derived by use of the minimum system method is substantially greater than from the zero intercept method that AmerenUE has used. Thus, the customer components in the distribution accounts are a low estimate of true customer-related distribution system costs.

Generally accepted practice in performing class cost of service studies is to identify a customer component in the primary distribution system, and neither OPC nor AARP have provided a basis for any other approach.

Q ARE THERE OTHER ISSUES WITH RESPECT TO THE ALLOCATION OF DISTRIBUTION ACCOUNTS?

A Yes, there are other issues with respect to the types of demands used to allocate some of the costs, but in comparison to the other issues in this proceeding, they are relatively minor, and I will not discuss them.

RECOMMENDED REVENUE ALLOCATION

Q HAVE YOU REVIEWED THE TESTIMONY OF OTHER WITNESSES WITH RESPECT TO THE ALLOCATION OF ANY CHANGE IN REVENUES?

A Yes. All of these witnesses (including AmerenUE) base their recommendation on the flawed class cost of service studies, and they should be rejected.

Q WHAT IS YOUR RECOMMENDATION FOR THE ALLOCATION OF REVENUE ADJUSTMENTS?

A As I indicated at page 37 of my direct testimony, the results of a proper class cost of service study show that the Large Primary Service class revenues should be reduced by about 3% on a revenue-neutral basis. After that adjustment, the Large Primary Service class should receive the average overall decrease or increase in revenues found appropriate for AmerenUE.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY ON COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN?

A Yes, it does.

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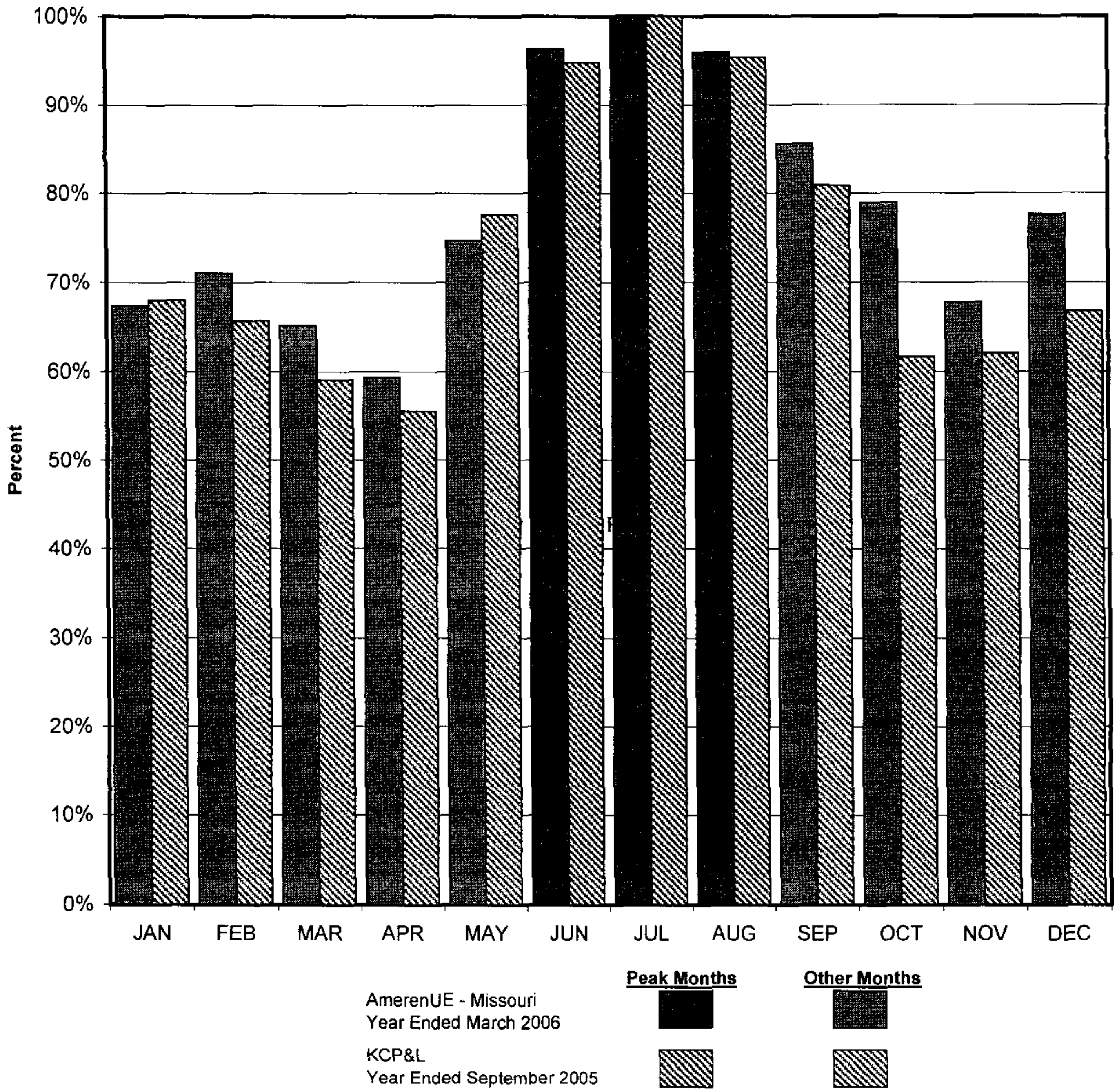
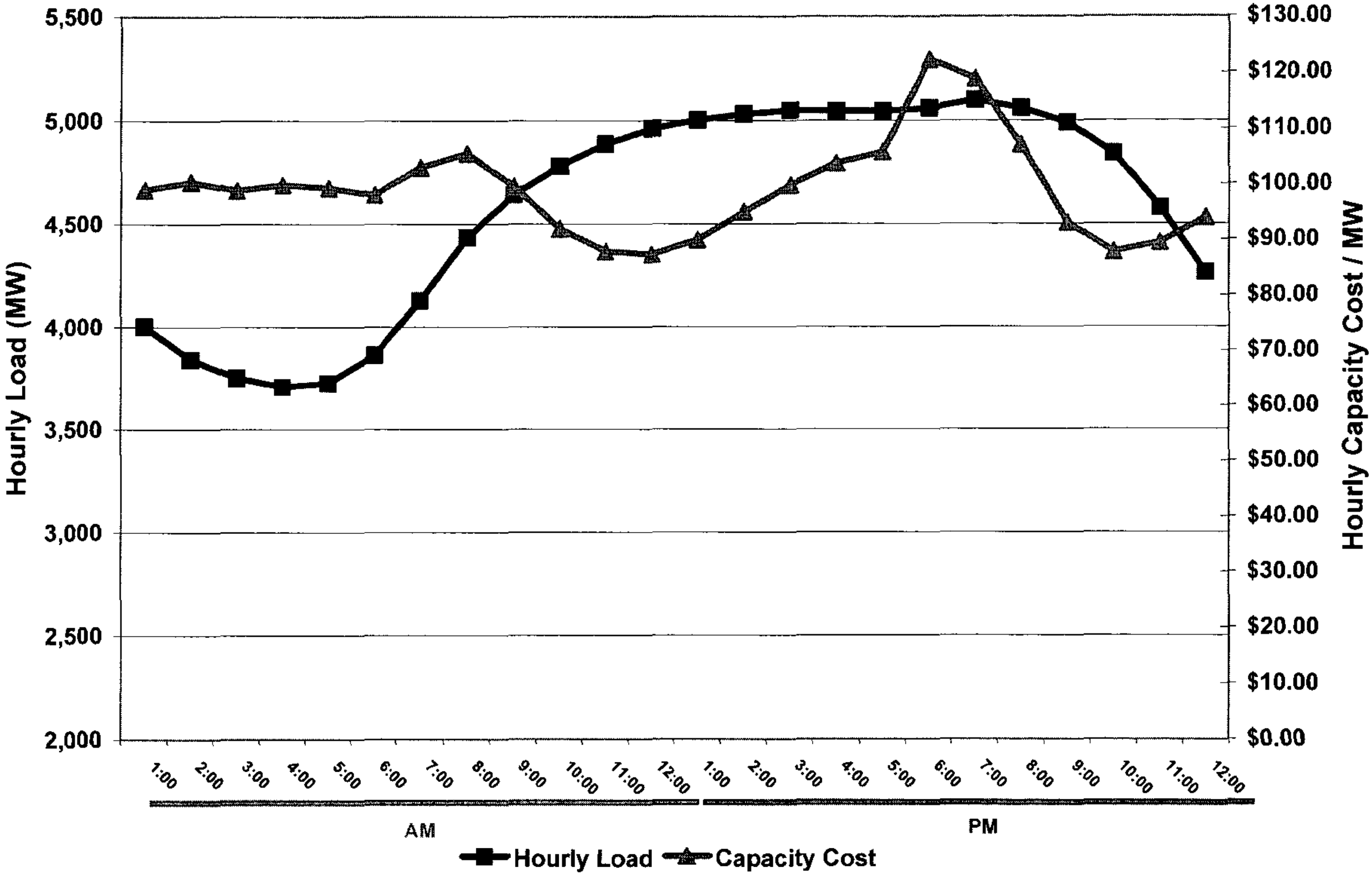
AmerenUE

Comparison of AmerenUE-Missouri and Kansas City Power & Light Company
Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak



AmerenUE

OPC'S HOURLY ASSIGNMENT OF GENERATION CAPACITY COSTS



Schedule MEB-COS-R-2

AmerenUE

CUSTOMER CLASS GENERATION CAPACITY COSTS PER KILOWATT AND ENERGY COSTS PER KWH UNDER TRADITIONAL METHODS AS COMPARED TO STAFF, AARP AND OPC PROPOSALS

	BAI Traditional Method				Staff COSS				AARP COSS				OPC COSS				OPC TOU-COSS			
	Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.	
Customer Class	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	126		1.08		126		1.08		126		1.08		126		1.08		126		1.08	
Res	126	0%	1.08	0%	108	-14%	1.08	0%	110	-13%	1.08	0%	111	-12%	1.05	-3%	98	-22%	1.05	-3%
Small GS	126	0%	1.08	0%	119	-6%	1.08	0%	119	-6%	1.08	0%	118	-6%	1.09	1%	111	-12%	1.09	1%
Large GS	126	0%	1.08	0%	136	8%	1.08	0%	135	7%	1.08	0%	134	6%	1.09	1%	141	12%	1.09	1%
Small PS	126	0%	1.08	0%	148	17%	1.08	0%	144	14%	1.08	0%	143	13%	1.09	1%	160	27%	1.09	1%
Large PS	126	0%	1.08	0%	156	24%	1.08	0%	152	21%	1.08	0%	152	21%	1.09	1%	176	40%	1.09	1%
Trans.	126	0%	1.08	0%	185	47%	1.08	0%	182	44%	1.08	0%	183	45%	1.12	4%	221	75%	1.12	4%

AmerenUE

Case 3: Staff Allocation, Staff Accounting, Staff Class Cost-Of-Service Results with Off-System Sales Revenue Allocated on Energy

FUNCTIONAL CATEGORY			RES	SGS	LGS	SP	LP	Trans	TOTAL
PRODUCTION	CAPACITY		$422,782,695	$110,997,687	$220,748,088	$103,913,041	$103,233,455	$88,136,427	$1,049,811,393
PRODUCTION	ENERGY		$158,639,119	$42,727,006	$93,539,533	$46,326,800	$47,715,416	$44,168,587	$433,116,461
TRANSMISSION	CAPACITY		$26,958,260	$7,077,642	$14,075,752	$6,625,897	$6,582,564	$5,619,919	$66,940,033
DISTRIBUTION	SUBSTATIONS	DEMAND	$2,364,876	$614,748	$897,499	$352,516	$243,047	$0	$4,472,685
	SUBSTATIONS	DEMAND	$20,973,403	$4,801,572	$8,440,114	$3,524,969	$3,253,657	$0	$40,993,716
DISTRIBUTION	OH/UG	SEC DEMAND	$14,971,167	$3,891,744	$5,681,736	$0	$0	$0	$24,544,646
DISTRIBUTION	OH/UG	CUSTOMER	$27,833,142	$3,765,302	$258,679	$17,618	$1,674	$27	$31,876,443
DISTRIBUTION	OH/UG	PRI DEMAND	$45,733,545	$11,888,401	$17,356,425	$6,817,184	$4,700,204	$0	$86,495,758
DISTRIBUTION	TRANSFORMERS	SEC. CUSTOMER	$11,308,550	$1,529,835	$105,101	$0	$0	$0	$12,943,485
DISTRIBUTION	TRANSFORMERS	DEMAND	$1,106,474	$243,555	$281,143	$0	$0	$0	$1,631,172
DISTRIBUTION	OPERATIONS		$12,078,024	$3,560,102	$3,431,818	$2,677,140	$2,397,898	$55,014	$24,199,996
DISTRIBUTION	MAINTENANCE		$2,842,472	$643,120	$792,422	$274,076	$192,709	$11,502	$4,756,301
DISTRIBUTION	SERVICES								
DISTRIBUTION	METERS		$6,315,458	$2,015,448	$563,521	$278,528	$85,519	$5,035	$9,263,509
DISTRIBUTION	DIRECT ASSIGNMENTS		($571,097)	$0	$0	$952,167	$952,167	$0	$1,333,236
	CUSTOMER DEPOSITS		($396,995)	($280,178)	($169,958)	($53,741)	-$32,478	$0	($933,351)
	METER READING		$14,808,245	$2,003,278	$221,216	$19,823	$3,886	$69	$17,056,517
	BILLING, SALES, SERVICE		$17,069,922	$1,223,110	$615,139	$164,778	$819,900	$73	$19,892,922
	A & G		$147,916,103	$36,539,549	$69,386,891	$33,034,711	$32,967,313	$27,233,363	$347,077,929
	CUSTOMER RECORDS		$17,094,951	$1,888,376	$2,689,554	$211,197	$18,618	$593	$21,903,289
	DEPRECIATION, TAXES, CWC		$143,361,486	$31,520,254	$47,301,643	$17,379,404	$16,002,088	$7,493,585	$263,058,459
TOTAL			$1,093,189,799	$266,650,549	$486,216,314	$222,516,108	$219,137,636	$172,724,194	$2,460,434,600
Allocate Cost of Service for Others			$0	$0	$0	$0	$0	$0	$0
TOTAL COST OF SERVICE			$1,093,189,799	$266,650,549	$486,216,314	$222,516,108	$219,137,636	$172,724,194	$2,460,434,600
%			44.43%	10.84%	19.76%	9.04%	8.91%	7.02%	100%
RATE REVENUE			$ 883,572,678	$ 239,245,325	$ 437,788,645	$ 185,248,099	$ 158,871,484	$ 135,652,313	$2,040,378,545
Allocate Revenue for Others			$ 13,852,110	$ 3,133,226	$ 5,079,043	$ 2,038,772	$ 1,940,763	$ 1,150,012	$27,193,926
OTHER REVENUE			$ 32,291,407	$ 6,328,255	$ 10,552,361	$ 4,591,651	$ 4,921,843	$ 3,278,452	$61,963,968
System and Interchange Sales			$ 195,502,985	$ 52,655,721	$ 115,275,842	$ 57,092,020	$ 58,803,316	$ 54,432,290	$533,762,173
TOTAL REVENUE			$ 1,125,219,180	$301,362,527	$568,695,891	$248,970,542	$224,537,405	$194,513,068	$2,663,298,613
%			42.25%	11.32%	21.35%	9.35%	8.43%	7.30%	100%
REVENUE DEFICIENCY			($32,029,381)	($34,711,978)	($82,479,576)	($26,454,434)	$ (5,399,769)	$ (21,788,874)	($202,864,013)
% CHANGE			-3.62%	-14.51%	-18.84%	-14.28%	-3.40%	-16.06%	-9.94%