Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Issues:	Revenue Requirement and Class Cost of Service Issues
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2010-0036

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service	))))))	**Case No. ER-2010-0036** Tariff Nos. YE-2010-0054 and YE-2010-0055

Rebuttal Testimony and Schedules of

Maurice Brubaker

Revenue Requirement and Class Cost of Service

On behalf of

Missouri Industrial Energy Consumers

February 11, 2010

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9187

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OF THE STATE OF MISSOURI

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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 is my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2010-0036.

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 S Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 10th day of February 2010.

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

Tammy S Klossner

Notary Public

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Rebuttal 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 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, revenue allocation and rate design 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.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"). These companies purchase substantial quantities of electricity from AmerenUE, principally at the primary and transmission voltage levels.

Q WHAT DO YOU ADDRESS IN THIS TESTIMONY?

A In this testimony, I respond to the direct testimony presented by the Missouri Department of Natural Resources ("MDNR"), by the Natural Resources Defense Council ("NRDC") and by the Missouri Energy Group ("MEG") on the subject of energy efficiency programs and cost recovery. I also respond to the testimony of the Staff of the Missouri Public Service Commission ("Staff") and to the testimony of the Office of Public Counsel ("OPC") with respect to class cost of service studies and related issues.

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My rebuttal testimony may be summarized as follows:

1. The proposals of MBNR and NRDC with respect to expensing (as opposed to capitalizing and amortizing) DSM expenditures should be rejected.

2. NRDC's proposal for a revenue decoupling mechanism ("RDM") should be rejected.

3. Issues concerning collection of energy efficiency expenditures from customers, and consideration of financial rewards or other incentives to utilities, should be addressed in Case No. EW-2010-0187 recently opened by the Commission.

4. The proposals of NRDC and MDNR to have AmerenUE increase its energy efficiency goals should not be adopted at this time. Any change in those goals should await a thorough analysis of AmerenUE's recently completed "Demand-Side Management Market Potential Study."

5. MEG's proposals with respect to the method of separating customers who have opted out of DSM programs from those who haven't, and the method of charging both sets of customers, are unclear.

6. The Average & Peak ("A&P") allocation methods applied by Staff and OPC are not 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.

7. The study which OPC calls "time-of-use ("TOU")" is not 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.

8. The alternative Staff study, which it refers to as "Capacity Utilization," is not explained as to methodology, supported as to theory or shown to be applicable to AmerenUE's system. This study also allocates fixed costs even more disproportionately (than the A&P studies) to large high load factor customers.

9. Neither the alternative Capacity Utilization method offered by Staff, nor the "TOU" method advanced as an alternative by OPC, are traditional. Neither are used in any other jurisdiction and have not ever been adopted by the Missouri PSC.

10. All of the Staff and OPC cost of service studies (A&P, TOU and Capacity Utilization) 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.

11. The Average & Excess ("A&E") approach that I offered in my direct testimony is the most appropriate allocation method for the AmerenUE system, and should be adopted by the Commission and used as a guide to distribute any revenue increase found appropriate.

12. Staff categorizes an excessive amount of production system non-fuel operation and maintenance ("O&M") expense as variable instead of fixed.

13. Staff and OPC both appear to allocate margins from off-system sales on demands rather than on energy. No justification is provided for this treatment.

ENERGY EFFICIENCY ISSUES

Q HAVE YOU REVIEWED THE TESTIMONY OF DR. ADAM BICKFORD AND LAURA WOLFE FILED ON BEHALF OF MDNR, AND THE DIRECT TESTIMONY OF PAMELA LESH FILED ON BEHALF OF NRDC?

A Yes, I have.

Q ARE THERE SOME COMMON THEMES IN THESE TESTIMONIES?

A Yes. Both parties support more aggressive demand-side management ("DSM") activities, along with accelerated cost recovery of DSM expenditures. They also favor some form of financial reward or additional compensation for utilities conducting DSM programs.

Q HOW HAVE YOU STRUCTURED YOUR RESPONSE TO THESE PARTIES?

A I will first respond to the general themes of the testimonies, referring back to my direct testimony and to other Commission proceedings, as appropriate. This will be followed by specific commentary on a few of the points and recommendations contained in the testimony of these parties.

Q WHAT PROPOSALS DID THESE PARTIES MAKE WITH RESPECT TO THE RECOVERY OF DSM EXPENDITURES?

A MDNR essentially repeats AmerenUE witness Kidwell's testimony about the recovery period and supports expensing of DSM costs. NRDC takes a similar point of view.

Q HAVE YOU PREVIOUSLY RESPONDED TO MR. KIDWELL, AND PROVIDED TESTIMONY CONCERNING THE APPROPRIATE MECHANISM FOR RECOVERY OF DSM EXPENDITURES?

A Yes. I addressed this issue in detail in my December 18, 2009 revenue requirement testimony from pages 8 through 16.

Q **HAVE MDNR AND NRDC OFFERED ANY SPECIFIC MECHANISM FOR COST RECOVERY?**

A No. They address this issue more in policy terms. Neither party put forth any specific cost recovery mechanism or tariff language.

Q **IS IT TIMELY TO CONSIDER ADOPTING SUCH PRACTICES AS REWARDS FOR ACHIEVING SUCCESS WITH ENERGY EFFICIENCY, REVENUE DECOUPLING PLANS, AND OTHER FINANCIAL COMPENSATION PLANS FOR UTILITIES CONDUCTING DSM?**

A No. It is premature.

Q **WHY DO YOU SAY THAT IT IS PREMATURE TO CONSIDER THESE MECHANISMS?**

A First, the parties to this case that are interested in the subject have been participating in confidential collaborative sessions designed to address these and other DSM issues. AmerenUE initiated this process, and has not requested any of these mechanisms in this case.

Q **IS THERE ANY OTHER FORUM IN WHICH THESE ISSUES CAN MORE APPROPRIATELY BE DISCUSSED?**

A Yes. On January 6, 2010, the Commission opened Case No. EW-2010-0187. The purpose of this case is to deal with implementation of Missouri Senate Bill 376. It also is to consider the implications of the Federal Energy Regulatory Commission's ("FERC") Order Nos. 719 and 719-A, both of which deal with demand-side response.

Q MOVING NOW TO SPECIFIC POINTS CONTAINED IN THE MDNR TESTIMONY, DR. BICKFORD SAYS AT PAGE 6, IN DISCUSSING SHAREHOLDER DISINCENTIVES TO DSM, THAT "SUPPLY-SIDE INVESTMENTS (E.G., TRADITIONAL POWER PLANTS) HAVE A KNOWN LEVEL OF RISK AND A KNOWN LEVEL OF RETURN." DO YOU AGREE WITH THAT STATEMENT?

A No. While I would agree that the kinds of risks applicable to both supply-side and demand-side resources can be identified, the result of the exposure to the risks, and the return that will be earned, are both unknown.

And, it should be noted that the potential for loss in connection with supply-side resources is much greater than in connection with demand-side resources. The reason is that supply-side resource choices generally involve the commitment of large amounts of capital over an extended time horizon. DSM investments, on the other hand, are in much smaller increments and can be turned on and turned off relatively easily in response to actual requirements and experience.

Q BOTH MDNR AND NRDC ARE IN FAVOR OF AMERENUE INCREASING ITS GOALS FOR DSM. ARE YOU IN AGREEMENT?

A No. Doing so would be premature. Much of the reasoning which is used to support increasing these goals is based on studies and experience in other states. These results may or may not be realistic expectation for AmerenUE.

Furthermore, AmerenUE is just completing its "demand potential" study. Prior to expanding the goals for AmerenUE's demand-side programs, this study needs to be carefully reviewed and evaluated in order to obtain a realistic assessment of DSM in the AmerenUE service territory that would be economic and realistically achievable.

Q OTHER THAN THE ISSUES WHICH YOU HAVE ADDRESSED ABOVE, DOES NRDC HAVE ANY ADDITIONAL RECOMMENDATIONS?

A Yes. NRDC makes a policy proposal that AmerenUE adopt an RDM.

Q DO YOU HAVE ANY COMMENTS ON THAT PROPOSAL?

A Yes. First, this proposal can be taken up for consideration in Case No. EW-2010-0187 that I previously described.

In addition, however, it should be pointed out that the RDM proposal that NRDC makes apparently would allow AmerenUE to adjust its revenues to a specified level without regard to weather normalization, the level of economic activity, or load loss as a result of ice storms or other catastrophic events. I do not think it takes much reflection to see that such a mechanism is not beneficial to customers. Consider AmerenUE in 2009. In general, temperatures were less extreme than normal resulting in lower than normal sales, the economy took a nose dive resulting in loss of sales to business customers, and an ice storm caused severe damage and significant curtailment of electric consumption by AmerenUE's largest customer. With an RDM, all of the revenue loss resulting from these events would be fed back into rates as an increase to customers.

Q THEN I TAKE IT YOU DISAGREE WITH MS. LESH'S TESTIMONY AT PAGE 28 WHERE SHE SAYS AN RDM "…DOES NOT SHIFT RISK BUT INSTEAD REDUCES RISK FOR BOTH CUSTOMERS AND THE UTILITY."?

A I certainly do disagree. There is no overall reduction in risk from adoption of an RDM mechanism. I think it is abundantly clear that, instead, all of the risk is shifted from the utility to the customer. The events of 2009 and the rate consequences that would have flowed from them had an RDM been in effect should be ample demonstration that this is the case.

Q HAVE YOU REVIEWED ATTACHMENT 1 TO MS. LESH'S TESTIMONY?

A Yes. This is a summary she prepared of decoupling mechanisms in other states.

Q DO YOU HAVE ANY COMMENTS ON THIS SURVEY?

A Yes. I think it is important to note that with the exception of California programs, most of those applicable to electric utilities are pilots and are in effect only for a specified period of time. It is also true that for the most part when there is such a mechanism it applies only to residential, and perhaps small business, customers.

Q ARE YOU AWARE OF STATES THAT HAVE REJECTED DECOUPLING TYPE MECHANISMS?

A Yes. Ms. Lesh indicated (in response to MIEC Data Request No. 1-19) that she was aware that the states of Indiana and Washington had done so.

As another example, the state of Maine adopted a trial "revenue per customer" decoupling mechanism for Central Maine Power Company in 1991. Shortly after implementation, Maine experienced a recession which resulted in lower sales levels. These lower sales levels caused the accrual of substantial deferrals that the utility was entitled to recover. The majority of the $52 million deferral was the result of the economic recession because of the decoupling mechanism. The decoupling mechanism effectively shielded the utility against the impact of the recession and passed the risk to customers. In 1993, the Commission cancelled the program.

Q FINALLY, AT PAGE 7 OF HER TESTIMONY, MS. LESH STATES THAT INCREASING ENERGY EFFICIENCY IMPROVES ECONOMIC COMPETITIVENESS FOR COMMERCIAL AND MANUFACTURING BUSINESSES. IS THAT STATEMENT TRUE UNDER ALL CIRCUMSTANCES?

A Let me begin my response by stating that industrial customers have, for decades, been attentive to their energy consumption and have taken steps to cost-effectively improve the efficiency of energy use. Certainly, implementing cost-effective energy efficiency measures is the right thing to do, and industry has a good track record of doing so.

However, it is not true that all expenditures that could be made toward energy efficiency are cost-effective. There comes a point of diminishing returns where additional investments in efficiency measures do not produce savings sufficient to justify the cost.

To make the blanket statement that Ms. Lesh makes is like saying that "if a little bit of something is good, a lot of it must be better." It is not true in the case of aspirin, and it is not true in the case of energy efficiency either.

Q HAVE YOU REVIEWED THE DIRECT TESTIMONY OF MEG WITNESS BILLIE SUE LACONTE CONCERNING ENERGY EFFICIENCY?

A Yes.

Q DO YOU HAVE ANY COMMENTS ON THAT TESTIMONY?

A Yes. Ms. LaConte sets forth a position with respect to the opt-out provision of Senate Bill 376, and makes a recommendation for how to charge customers appropriately for energy efficiency expenditures.

Q DO YOU AGREE WITH HER PROPOSAL THAT ENERGY EFFICIENCY EXPENDITURES SHOULD BE TRACKED AND CHARGED TO CUSTOMERS BY RATE SCHEDULE, SUCH THAT EXPENDITURES ARE CHARGED ONLY TO CLASSES THAT RECEIVE THE SPECIFIC BENEFITS OF THE PROGRAMS?

A Yes. It is appropriate that energy efficiency expenditures be tracked in this fashion because the primary beneficiaries of the energy efficiency expenditures are those customers that receive the direct bill reduction benefits that result from the installation of the energy efficiency measure. Residential customers will receive the benefit of residential programs through lower bills enjoyed by the customers who take advantage of the programs. To the extent that there are reductions in peak demands (which AmerenUE anticipates will be the case), the entire class will benefit in future cost allocations when the amount of generation and transmission capacity allocated to the class will decrease.

Q HOW DOES MS. LACONTE PROPOSE TO CHARGE CUSTOMERS?

A This is not clear. She speaks in terms of a "surcharge" applicable to the customers in each class that have not opted out. However, she does not indicate how this surcharge would be applied, other than to say customers who opt-out will not face the surcharge. It is not clear whether she intends that the surcharge be redetermined periodically in between rate cases, or whether she intends this as a mechanism and a specific value to be determined in each rate case, and remain in effect until the next rate case. If the intent is that it be allowed to vary between rate cases, then I oppose this approach.

CLASS COST OF SERVICE ISSUES

Q HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESSES MICHAEL SCHEPERLE AND OPC WITNESSES RYAN KIND AND BARBARA MEISENHEIMER 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 fixed costs is the largest and most important of these issues, and I will address it first.

Staff Study

Q WHAT METHOD HAS STAFF USED FOR THE ALLOCATION OF GENERATION FIXED, OR DEMAND-RELATED, COSTS?

A Staff's recommended method is an A&P allocation method. In particular, Staff uses the four monthly 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. The result is to give 45% weighting to the contributions to the four monthly coincident peaks, and 55% weighting to annual energy consumption.

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

A No. While Staff explains the basis for the use of the four summer peaks, it neither explains the derivation of the particular allocation factors, nor does it explain or attempt to justify why this particular averaging method is appropriate for AmerenUE.

Furthermore, in its alternate method, Staff determines its weighting of monthly class demands by using a methodology that is described in a 26-year old magazine 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 2008 on the AmerenUE system.

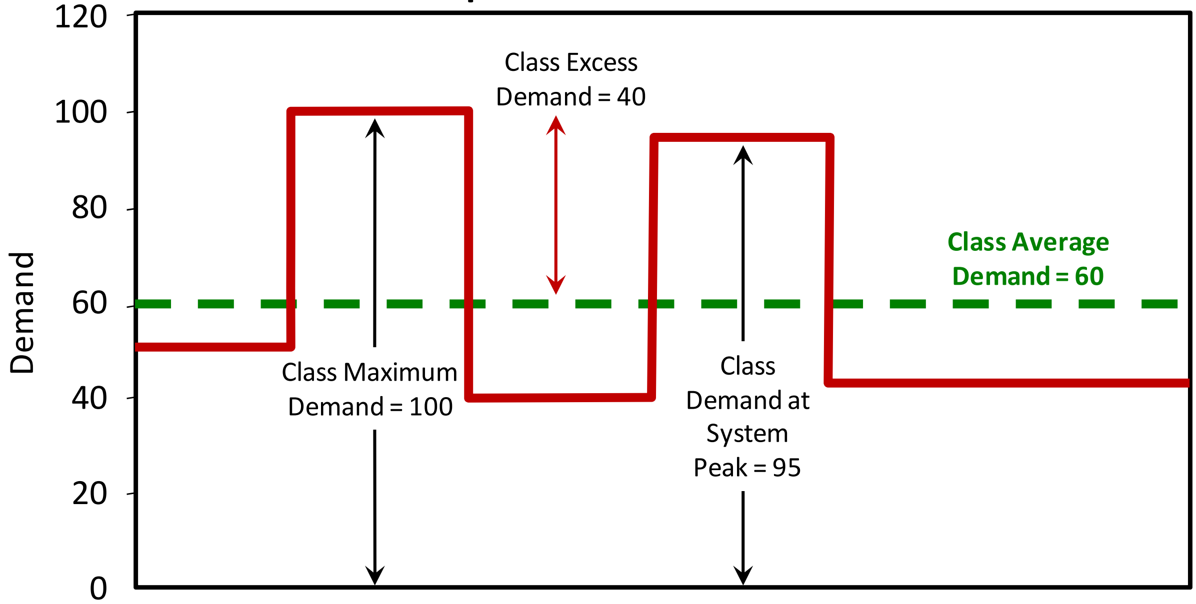
Q HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE A&E METHODOLOGY THAT YOU USED IN YOUR CCOS STUDY?

A Staff's A&P allocator is constructed by multiplying each class's energy responsibility factor (average demand) times the system load factor, and adding that result to each class's percentage contribution to the weighted class peaks 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

Components of Allocation Factor



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 60, and the excess demand (the difference between its peak demand and its average demand) is 40.

As explained in more detail beginning at page 23 of my direct testimony, 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's maximum demand over its average demand. The A&E allocation factor is developed using the average demand (60) and the excess demand (40) for this class, along with the corresponding demands for all other classes. (This is shown in detail on Schedule MEB-COS-3 attached to my direct testimony on cost of service.)

Staff's A&P method, on the other hand, combines the average demand with the class monthly peak demands. As is evident from Figure 1, the average demand (60) is a component or sub-set of the class peak demand (100) and of the class load coincident with the system peak (95). Accordingly, in the A&P method 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 class peaks used in the allocation of the investment in generation facilities. Since generation facilities must be designed to carry the peak loads imposed on them, the roughly equal weighting given 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 ALTERNATE CAPACITY UTILIZATION ALLOCATION METHOD GIVE TO SUMMER DEMANDS?

A Staff uses class demands from all 12 months, regardless of their magnitude, and weights them. However, Staff presents evidence that shows that the peak demand during a single summer month (August) was significantly higher than any other month during the year. The second highest peak demand occurred in June, and was 3%

below the August peak. Although not explained in the testimony, the information presented in the Staff's workpapers shows that the peak demand occurring in August has a weighting of about 7% in Staff's alternate allocation factor, which means that loads at other times are weighted 93%, or 13 times as much.

A similar analysis of the two highest peak demands that occurred during August and July reveals that these peaks have a combined weighting of less than 13%, while the loads at other times are weighted nearly seven 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 7% to 13% weighting to the highest 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 A 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 justify the use of summer peak demands for jurisdictional allocation compel the use of that 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. This is because the differences among 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 ALTERNATE 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 was not used anywhere to the best of its knowledge. I would concur with that conclusion.

Q HAVE YOU REVIEWED STAFF'S TREATMENT OF NON-FUEL PRODUCTION SYSTEM O&M EXPENSE?

A Yes. My review of Staff's workpapers indicates that the separation between fixed and variable components is essentially the same as applied by AmerenUE. For the reasons expressed in my direct testimony, I believe that Staff has understated the amount of fixed O&M expense and overstated the amount of variable O&M expense.

OPC Studies

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

A OPC used a four-month coincident peak A&P allocator (same method used by Staff) 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. As shown on Figure 1, the average demand is a component or sub-set of the contribution to the system peak(s) demand, so <u>OPC's method double-counts the average demand – just like Staff's method</u>.

Furthermore, Ms. Meisenheimer just calls her second study a "TOU" study and provides only a sketchy 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 TO DEVELOP THE WEIGHTING FOR THE DEMAND COMPONENT AND THE ENERGY COMPONENT OF ITS A&P ALLOCATION FACTOR, WHAT LOAD FACTOR DID OPC USE?

A OPC used a 55.6% load factor. OPC's method of developing the system load factor produced a higher system load factor than what AmerenUE calculated.

Q HOW MUCH WEIGHT IS GIVEN TO SUMMER PEAK DEMANDS IN OPC'S TOU STUDY?

A The summer peak demand is weighted only 0.05% (five one-hundredths of one percent) in OPC's study. This is the case because the OPC's TOU method considers every hour in the year to be a demand peak. Therefore, the four peak hours during the summer months are given no more weight than any other hour. The summer peak weighting is found by dividing the four summer peak hours by the total number of hours in the year (i.e., 8,760) and results in a weighting of 0.05%.

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

A Only very generally. A review of her testimony and 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 cost 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 nearly 80% of the capacity cost in late afternoon (2:00 p.m. - 7:00 p.m.), when the peak is occurring.

There is no reasonable basis to believe that loads in the middle of the night or during weekends 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 HAVE YOU REVIEWED OPC'S TREATMENT OF PRODUCTION SYSTEM O&M EXPENSE?

A Yes. It appears that OPC has generally allocated the non-fuel O&M expense on the basis of plant, which is effectively treating it as a fixed cost. It is somewhat difficult to tell what OPC has done because OPC's production O&M expenses are about $135 million higher than those of other parties. It appears that this may have been attributable to inadvertently leaving in the cost study roughly that amount of fuel expense that is properly attributable to off-system sales.

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 and OPC 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 AND OPC?

A These Staff and OPC 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 of capital costs.

Given these allocations of capital cost, it would not be appropriate 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 heavily energy-weighted Staff or OPC 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 PERFORMED ANY CALCULATIONS AND DEVELOPED A SCHEDULE TO ILLUSTRATE THIS?

A Yes, I have. Please refer to page 1 of 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 A&E allocation method, Staff's A&P method, Staff's alternative "Capacity Utilization" 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 and applied my allocation factors (traditional) as well as the Staff and OPC 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 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, 18% more to the Large Primary class and 46% more to the Large Transmission class than under the traditional approaches, which allocate average capacity costs to all classes. Note also that fuel costs per kWh are the same for all classes. The third block shows the results for Staff's Capacity Utilization study.

The fourth block shows similar class capacity allocation results for OPC's A&P study. Note also that the energy-related costs are the same for all classes.

The final block shows the OPC "TOU" study. Predictably, an even heavier allocation of capacity costs is made to the Large Primary class (28% above the average) and the Large Transmission class (73% above the average); while even less is allocated to the Residential class. The energy costs are once again the same for each class.

Page 2 of Schedule MEB-COS-R-3 shows the skewing graphically, using Staff's A&P method for illustration. (This is the least skewed study – the others have a greater skew.)

Q YOU INDICATED THAT THE ENERGY COSTS PER KWH ARE THE SAME 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 about 0.5¢ per kWh, the base load coal plants have fuel costs in the range of 1.2¢ to 1.8¢ per kWh, the more efficient peaking units have fuel costs of 8¢ to 15¢ per kWh, and other peakers have costs that are 25¢ and higher. (Note: These fuel costs are taken from AmerenUE's 2008 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 lower than average. None of the allocation methods advanced by Staff and OPC recognize this correspondence, and as a result over-allocate costs to high load factor customers.

Q WHAT SHOULD BE CONCLUDED FROM SCHEDULE MEB-COS-R-3?

A This schedule clearly demonstrates that the A&P and the "TOU" methods that have been sponsored in this case by Staff and OPC are highly non-symmetrical. They burden high load factor classes with above-average capacity costs, but do not allow them to benefit from the lower cost of energy that goes with the higher capacity costs. No theory supports this result and these flawed studies 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 a 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 among class load factors are much greater than the differences between jurisdictional load factors.

Importance of Precedent

Q IN EARLIER TESTIMONY, YOU POINTED OUT THAT 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 has 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 TRANSMISSION COSTS

Q HOW HAVE STAFF AND OPC ALLOCATED TRANSMISSION COSTS?

A Staff and OPC have used the 12 monthly coincident peak demands of customer classes to allocate transmission costs.

Q IS THIS APPROPRIATE?

A No. Just like the generation system, the transmission system must be built to meet the peak demands imposed on it. Accordingly, the average and excess method should be used to allocate transmission system costs.

ALLOCATION OF REVENUE FROM OFF-SYSTEM SALES OF ENERGY

Q HOW HAVE STAFF AND OPC ALLOCATED THE MARGINS FROM OFF-SYSTEM SALES?

A It appears that both OPC and Staff have allocated the net margins (revenues minus estimated fuel and purchased power costs) to classes on the basis of a demand allocation factor. This is comparable to AmerenUE's allocation, which I believe to be inferior to an energy-based allocation.

Q YOU INDICATED IN YOUR DIRECT TESTIMONY THAT IN A 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 AND THE OPC PROPOSE TO ALLOCATE REVENUE FROM OFF-SYSTEM SALES?

A 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 this state" of Missouri. I agree.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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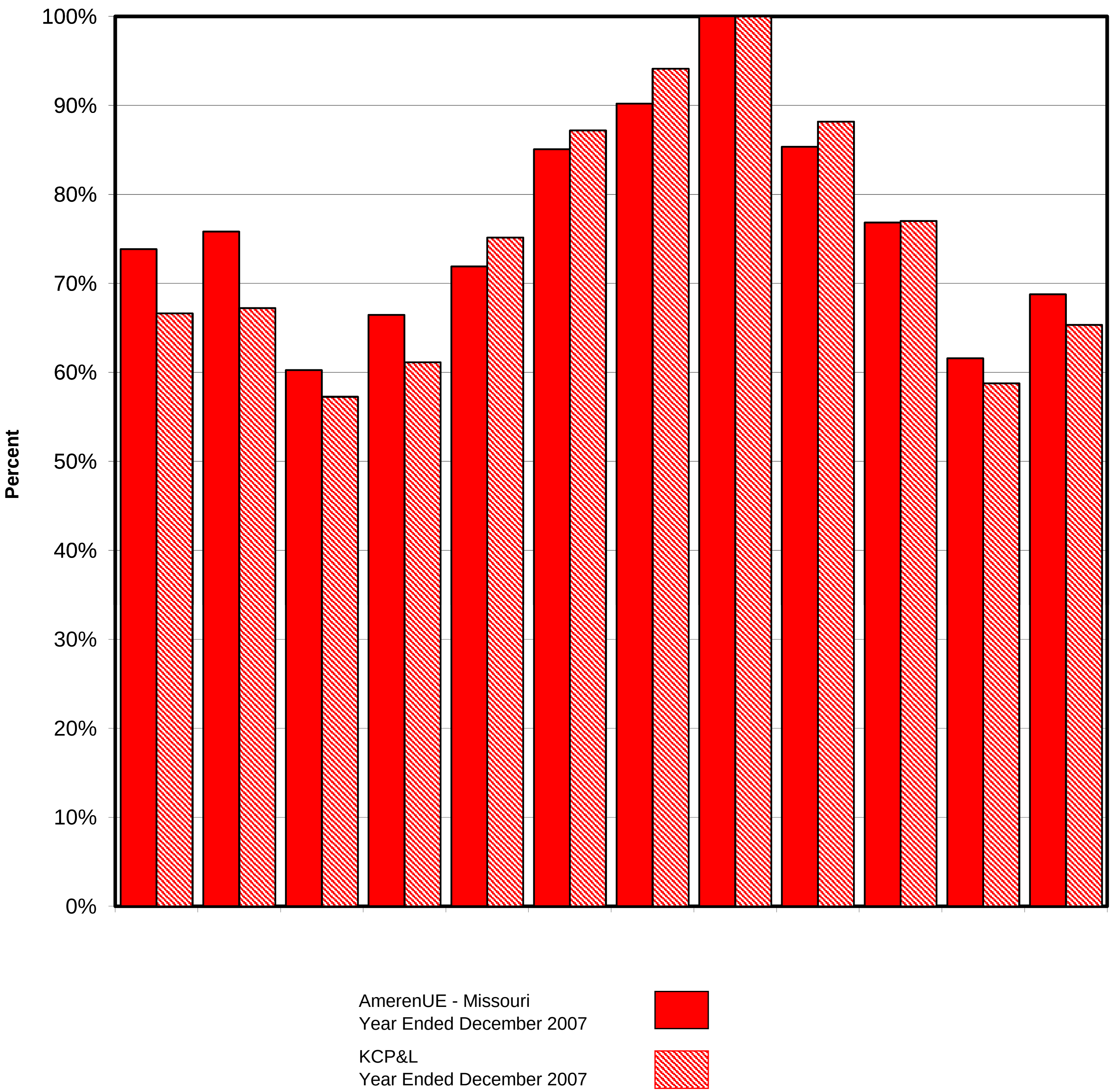
AmerenUE

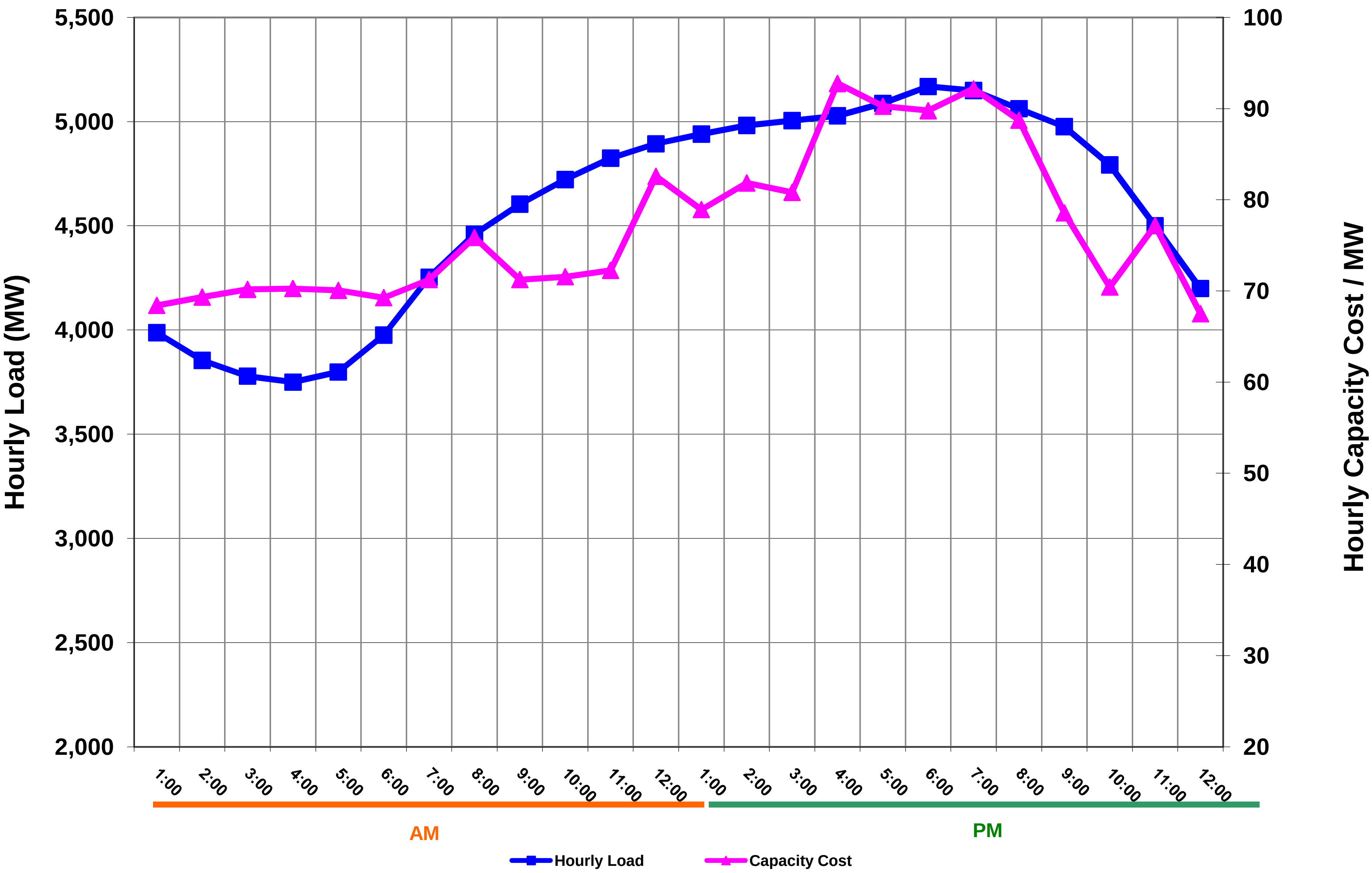
Comparison of AmerenUE-Missouri and Kansas City Power & Light Company
Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak



Schedule MEB-COS-R-1

AmerenUE

OPC'S HOURLY ASSIGNMENT OF GENERATION CAPACITY COSTS



Schedule MEB-COS-R-2

AmerenUE

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

MIEC COST OF SERVICE STUDY

	Traditional Avg. & Excess CCOS			
	Capacity Rev Req.		Energy Rev Req.	
Customer Class	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	113		2.15	
Res	113	0%	2.15	0%
Small GS	113	0%	2.15	0%
Large GS/Small PS	113	0%	2.15	0%
Large PS	113	0%	2.15	0%
Trans.	113	0%	2.15	0%

MISSOURI COMMISSION STAFF COST OF SERVICE STUDIES

	Staff Avg. and Peak CCOS				Staff Capacity Utilization CCOS			
	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.
Total	113		2.15		113		2.15	
Res	99	-12%	2.15	0%	98	-13%	2.15	0%
Small GS	107	-5%	2.15	0%	107	-5%	2.15	0%
Large GS/Small PS	121	7%	2.15	0%	122	8%	2.15	0%
Large PS	133	18%	2.18	1%	135	19%	2.12	-1%
Trans.	165	46%	2.18	1%	168	49%	2.18	1%

OFFICE OF PUBLIC COUNSEL COST OF SERVICE STUDIES

	OPC Avg. and Peak CCOS				OPC TOU CCOS			
	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.
Total	113		2.15		113		2.15	
Res	98	-13%	2.15	0%	92	-19%	2.15	0%
Small GS	106	-6%	2.15	0%	100	-12%	2.15	0%
Large GS/Small PS	122	8%	2.15	0%	125	11%	2.15	0%
Large PS	137	21%	2.15	0%	145	28%	2.15	0%
Trans.	163	44%	2.15	0%	196	73%	2.15	0%

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Illustration of Skewed Allocation of Capital Costs and
Energy Costs Under Staff's and OPC's Allocation Proposal:
Illustrated using Staff's Avg. & Peak CCOS