Exhibit No.:
Issues: Cost of Service, Revenue Allocation, and Rate Design
Witness: Maurice Brubaker
Type of Exhibit: Rebuttal Testimony
Sponsoring Party: Missouri Industrial Energy Consumers
Case No.: ER-2012-0166
Date Testimony Prepared: August 14, 2012

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company,)
d/b/a Ameren Missouri's Tariff to Increase)   **Case No. ER-2012-0166**
Its Annual Revenues for Electric Service)   Tariff No. YE-2012-0370
)
)

Rebuttal Testimony and Schedule of

Maurice Brubaker

**on Cost of Service, Revenue
Allocation and Rate Design**

On behalf of

Missouri Industrial Energy Consumers

August 14, 2012

BAI

BRUBAKER & ASSOCIATES, INC.

MIEC Exhibit No 505
Date 9-20-12 Reporter FF
File No ER-2012-0166

Project 9553

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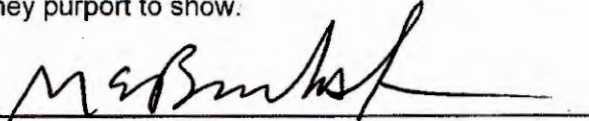| STATE OF MISSOURI	)	
	)	SS
COUNTY OF ST. LOUIS	)	

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.
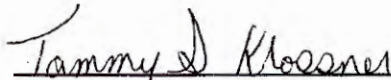
2.   Attached hereto and made a part hereof for all purposes are my rebuttal testimony and schedule which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2012-0166.

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

_____
Maurice Brubaker

Subscribed and sworn to before me this 13th day of August, 2012.

_____
Notary Public
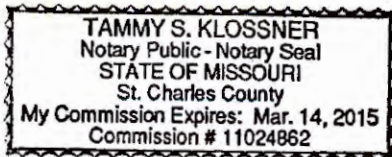
BRUBAKER & ASSOCIATES, INC.

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Schedule MEB-COS-R-1

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Rebuttal Testimony of Maurice Brubaker

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

2 A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140,

3 Chesterfield, MO 63017.

4 **Q ARE YOU THE SAME MAURICE BRUBAKER WHO HAS PREVIOUSLY FILED**

5 **TESTIMONY IN THIS PROCEEDING?**

6 A Yes. I have previously filed direct testimony on class cost of service, revenue

7 allocation and revenue requirement issues presented in this proceeding.

8 **Q ARE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN**

9 **YOUR PRIOR TESTIMONY?**

10 A Yes. This information is included in Appendix A to my revenue requirement direct

11 testimony filed July 6, 2012.

12 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

13 A This testimony is presented on behalf of the Missouri Industrial Energy Consumers

14 ("MIEC").

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INTRODUCTION AND SUMMARY

1

2 Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

3 A In my rebuttal testimony I will address the cost of service and revenue allocation

4 proposals put forth by the Staff of the Public Service Commission ("Staff") and the

5 Office of Public Counsel ("OPC").

6 Q **PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

7 A They may be summarized as follows:

8 1. OPC's preferred allocation of generation fixed, or demand-related, costs is
9 premised on an average and peak ("A&P") allocation method that has been
10 rejected by this and other commissions. It double counts energy consumption
11 and over-allocates costs to high load factor customers, and should again be
12 rejected.

13 2. Staff has developed an alternative Base, Intermediate and Peaking ("BIP")
14 method that differs materially from the BIP method described in the NARUC Cost
15 Allocation Manual and the BIP proposed for implementation in the current Kansas
16 City Power & Light Company ("KCPL") case. This version of BIP is not an
17 accepted method and should not be endorsed in this case.

18 3. Staff's actual implementation of BIP is based on development of a composite
19 allocation factor that is constructed by looking at several different measures of
20 class load responsibility. The alternative application proposed by Staff in this
21 case produces results that are sim ilar to traditional allocation methods.

22 4. OPC's proposal to allocate the margin earned from off-system sales ("OSS") on a
23 demand basis has previously been rejected by the Commission and should
24 continue to be rejected in this case.

25 5. OPC's proposed allocation of the investment and expenses associated with
26 energy efficiency ("EE") is inappropriate and is not consistent w ith cost causation.

27 6. Neither Staff nor OPC recognizes the substantial difference among customer
28 classes with respect to the incurrence and recovery of EE costs. The equal
29 percent, or nearly equal percent in the case of Commission Staff, allocation of any
30 increase among customer classes fails to recognize these distinctions and would
31 be particularly burdensome on the Large Transmission Service ("LTS") customer
32 who has opted out of participation in Ameren Missouri's EE programs.

1   7. The percentage increase to the LTS class should be at least 4.0 percentage
2   points <u>below</u> the average increase for the following reasons:

3   a. No costs were allocated to the LTS class in Ameren Missouri's Missouri
4   Energy Efficiency Investment Act ("MEEIA") case, EO-2012-0142.

5   b. Unless the increase to LTS is at least 4.0 percentage points below the
6   average increase, the LTS customer will effectively be allocated responsibility
7   for a portion of the EE costs, which it is not causing or participating in.

8   c. The failure to appropriately recognize the specific assignment of EE costs
9   would result in an allocation that is clearly wrong, inconsistent with the letter
10   and spirit of the MEEIA legislation and the Commission rules, and would deny
11   this customer the benefit of the opt-out provision.

CLASS COST OF SERVICE ISSUES

13 **Q** **HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESS**

14   **MICHAEL SCHEPERLE AND OPC WITNESS BARBARA MEISENHEIMER ON**

15   **THE SUBJECT OF CLASS COST OF SERVICE?**

16 **A** Yes.

17 **Q** **DO YOU HAVE REBUTTAL TO THE COST OF SERVICE POSITIONS OF THESE**

18   **WITNESSES?**

19 **A** Yes, I do. I disagree with the methods which OPC has used for the allocation of

20   production and transmission fixed costs and with respect to the allocation of certain

21   other components of the cost of service. I have minor disagreements with the

22   Commission Staff's study.

OPC's Study

1

2 **Q WHAT METHOD HAS OPC USED FOR THE ALLOCATION OF GENERATION**
3 **FIXED, OR DEMAND-RELATED, COSTS?**

4 A OPC's recommended method is an A&P allocation method. In particular, OPC uses

5 the four monthly coincident peak demands of each customer class along with each

6 class's annual energy consumption. The energy component is weighted equal to the

7 system's annual load factor. The result is to give only about 45% weighting to the

8 contributions to the four monthly coincident peaks, and 55% weighting to annual

9 energy consumption.

10 **Q DOES OPC EXPLAIN THE BASIS FOR SELECTING THIS ALLOCATION**
11 **METHODOLOGY?**

12 A No. While OPC explains the basis for the use of the four peaks, it does not explain or

13 attempt to justify why this particular averaging method is appropriate for Ameren

14 Missouri.

15 **Q DOES THE FACT THAT A METHOD IS MENTIONED IN THE NATIONAL**
16 **ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC") COST**
17 **ALLOCATION MANUAL GIVE IT CREDIBILITY OR SUGGEST THAT IT IS**
18 **ACCEPTED IN THE INDUSTRY?**

19 A No.

20 **Q PLEASE EXPLAIN.**

21 A The fact that a particular method is noted in the Cost Allocation Manual simply means

22 that the individuals who prepared the Cost Allocation Manual included it because it

1   had been recommended by participants in one or more rate cases. There are a

2   number of allocation methods that are described in the Cost Allocation Manual that

3   are not commonly used and that have not found wide support in the industry. OPC's

4   A&P allocator clearly falls into that category.

5 **Q**   **HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE**

6   **AVERAGE AND EXCESS ("A&E") METHODOLOGY THAT YOU AND AMEREN**

7   **MISSOURI USED IN YOUR CCOS STUDIES?**

8 **A**   OPC's A&P allocator is constructed by multiplying each class's percentage energy

9   responsibility factor (average demand) times the system load factor, and adding that

10   result to each class's percentage contribution to the class peaks multiplied by the

11   quantity one minus the load factor.

12   Both the A&P and A&E methods are two-step processes. In both methods,

13   the first step is to weight the average demand by the system load factor. The second

14   step is where a major difference occurs. This is illustrated in Figure 1.

Figure 1

Components of Allocation Factor
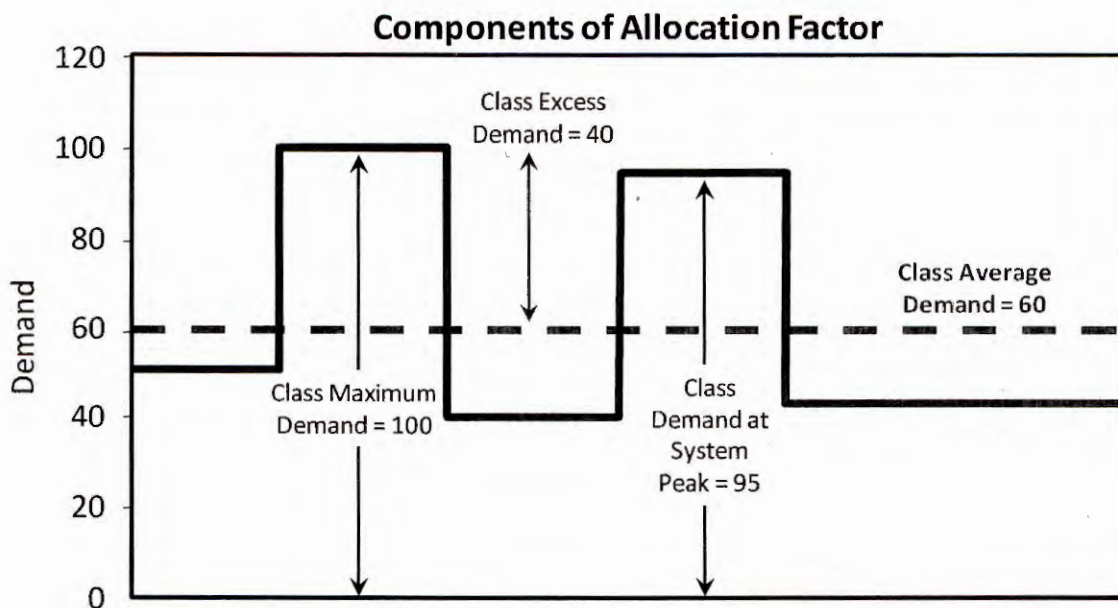
1 **Q**   **PLEASE REFER TO FIGURE 1 AND EXPLAIN THE DIFFERENCES.**

2 A   Figure 1 is a simplified representation of a class load. The maximum demand of this

3   particular class is represented as 100. Its contribution at the time of the system peak

4   is 95, its average demand is 60, and the excess demand (the difference between its

5   peak demand and its average dem and) is 40.

6   As explained in more detail beginning at page 24 of my direct testimony on

7   cost of service, the A&E method combines the class average demand with the class

8   excess demand in order to construct an allocation factor that reflects average use as

9   well as the excess of each class's maximum demand over its average demand. The

10   A&E allocation factor is developed using the average demand (60) and the excess

11   demand (40) for this class, along with the corresponding demands for all other

12   classes. (This is shown in detail on Schedule MEB-COS-3 attached to my direct

13   testimony on cost of service.)

1   OPC's A&P method, on the other hand, combines the average demand with

2   the class monthly peak demands. As is evident from Figure 1, the average demand

3   (60) is a component or sub-set of the class peak demand (100) and of the class load

4   coincident with the system peak (95). Accordingly, in the A&P method when roughly

5   equal weighting is given to the average demand and the contribution to system peak

6   demand, the average demand is double-counted. This is a serious error, and has the

7   effect of allocating significantly more costs to high load factor customers than is

8   appropriate.

9 Q HAS THE COMMISSION PREVIOUSLY RULED ON OPC'S PROPOSED

10   METHOD?

11 A Yes. The Commission has previously rejected the use of the A&P method.

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

13 A No, it is not. As noted above, this allocation gives more weighting to annual energy

14   consumption than to the class peaks used in the allocation of the investment in

15   generation facilities. Since generation facilities must be designed to carry the peak

16   loads imposed on them, the heavy weighting given to energy consumption in the

17   allocation factor is not related to cost of service at all.

18   Unlike the A&E method, which considers class individual peaks and class load

19   factors, as well as diversity between class peaks and system peak, the A&P method

20   arbitrarily allocates about half of these costs on annual energy consumption.

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1	Q	HAVE YOU REVIEWED OPC'S TREATMENT OF NON-FUEL GENERATION
2		SYSTEM OPERATION AND MAINTENANCE ("O&M") EXPENSE?
3	A	Yes. Ms. Meisenheimer states on page 14 of her direct testimony that she followed
4		the "commonly accepted practice in CCOS studies of having expenses follow plant"
5		and then explained that this means that O&M costs are allocated in the same manner
6		as the corresponding plant.

7	Q	DID MS. MEISENHEIMER FOLLOW THIS TREATMENT FOR NON-FUEL
8		GENERATION O&M EXPENSE?
9	A	No, not entirely. From her workpapers it appears that she did apply this method for
10		the allocation of non-fuel generation O&M expense associated with steam, nuclear
11		and hydro facilities. However, for the category of other generation, she allocated a
12		significant amount of the expenses on the energy factor rather than on the demand
13		allocation factor.
14		I agree with her allocation of generation non-fuel O&M expenses for steam,
15		nuclear and hydro facilities on the demand allocation factor, but disagree with her
16		allocation of the other generation expenses for reasons I explained in my direct
17		testimony on cost of service.

| 18 | Q | HOW DID MS. MEISENHEIMER ALLOCATE THE MARGIN EARNED FROM OSS? |
| 19 | A | She allocated this margin based on class demand allocation factors. |

1   Q   **IS THIS APPROPRIATE?**

2   A   No, it is inconsistent with this Commission's recent findings that the margin from OSS

3   should be allocated on the basis of class energy sales and not on the basis of class

4   demands.

5   Q   **HOW DID MS. MEISENHEIMER ALLOCATE THE PORTION OF THE**

6   **DISTRIBUTION SYSTEM INVESTMENT AND RELATED EXPENSES THAT**

7   **AMEREN MISSOURI IDENTIFIED AS CUSTOMER RELATED?**

8   A   To allocate the customer-related portion of Account Nos. 364 (Poles, Towers and

9   Fixtures), 365 (Overhead Conductors and Devices), 366 (Underground Conduit),

10   367 (Underground Conductors and Devices), 368 (Line Transformers) and

11   369 (Services) she used what she called "weighted meter investment" instead of

12   number of customers. Ameren Missouri used number of customers which is the

13   traditional and appropriate basis for allocating the customer-related portion of these

14   investments.

15   Ms. Meisenheimer's decision to substitute weighted meter investment for

16   number of customers results in a substantial, and unjustified shifting of the cost

17   responsibility of these customer-related facilities from the smaller (mainly residential)

18   customers to larger customers.

19   Q   **WHAT IS THE IMPACT OF THE ALLOCATION?**

20   A   For the customer-related portion of the enumerated accounts in the distribution

21   system, Ms. Meisenheimer's allocation factor for the Large Primary Service ("LPS")

22   class is 1.08%, as compared to Ameren Missouri's allocation factor for the LPS class

1   of 0.0057%. Ms. Meisenheimer's allocation factor is almost 190 times as large as

2   Ameren Missouri's.

3   As a result, her allocation to the LPS class for the total distribution system is

4    $199 million of investment, as compared to Ameren Missouri's allocation of

5    $138 million of investment.

6 **Q** **ARE YOU AWARE OF ANY PRECEDENT OR AUTHORITY FOR THE**

7   **ALLOCATION OF THE CUSTOMER COMPONENT OF THE DISTRIBUTION**

8   **SYSTEM THAT MS. MEISENHEIMER HAS APPLIED?**

9 **A** No, I am not. The conventional, and correct, approach is the one followed by Ameren

10   Missouri which allocates the customer-related components of the enumerated

11   distribution system accounts on the basis of the number of customers, and not some

12   weighted allocation that was designed to recognize the higher than average

13   investment in meters for large customers. The customer component in the

14   enumerated accounts is just that – a customer component which is the same cost for

15   every customer taking service at the distribution level. The skewed allocation applied

16   by Ms. Meisenheimer is inappropriate and should be rejected.

17 **Q** **HOW DID MS. MEISENHEIMER ALLOCATE THE COSTS ASSOCIATED WITH EE**

18   **PROGRAMS?**

19 **A** She allocates the expenses using her production demand allocation method. This is

20   inconsistent with the Stipulation in the MEEIA proceeding, Case No. EO-2012-0142,

21   to which OPC was a signatory. Instead of this broad allocation, it is appropriate to

22   assign these costs to specific customer classes. She allocates the EE rate base

1   component using a weighted meter allocation factor, which has no relationship to EE

2   costs.

3   Her treatment of both components is inappropriate and fails to correlate the

4   allocation of the costs with the use of DSM programs by customer classes.   The

5   approach used by Ameren, by Staff, and by me does correlate and should be used.

6   Q   DID MS. MEISENHEIMER PRODUCE A SECOND CLASS COST OF SERVICE

7   STUDY?

8   A   Yes.   She also produced a cost study using essentially the same Average and

9   Excess – 4NCP ("A&E – 4NCP") allocation method that Ameren Missouri used.

10   Q   IS HER A&E – 4NCP STUDY APPROPRIATE?

11   A   No. It contains all of the same inappropriate allocations of generation non-fuel O&M

12   expense, the margin on OSS, the customer component of the distribution system,

13   and EE costs that I noted above in connection with my description of and rebuttal to

14   her A&P study.

15   **Staff's Study**

16   Q   WHAT METHOD DID COMMISSION STAFF USE FOR THE ALLOCATION OF

17   GENERATION FIXED, OR DEMAND-RELATED, COSTS?

18   A   Mr. Scheperle states that he has used something called the BIP method. In fact,

19   however, Mr. Scheperle has applied what I think is best described as an alternative

20   version of the BIP method. The BIP method described in the NARUC Cost Allocation

21   Manual, and as proposed to be implemented in the KCPL rate case, Case No.

22   ER-2012-0174, develops separate allocation factors for different categories of plant.

1   The BIP method is not an accepted method in the industry and rarely has been used,

2   or even proposed. In fact, the principal proponent of the BIP method in the KCPL

3   rate case was only able to identify one instance in the 30 years that he had been

4   proposing the BIP method that it had been adopted by a public service commission.

5 Q **HOW DOES MR. SCHEPERLE'S MODIFIED BIP DIFFER FROM THE BIP**

6   **METHOD DESCRIBED IN THE NARUC COST ALLOCATION MANUAL AND AS**

7   **PROPOSED FOR IMPLEMENTATION IN THE KCPL CASE?**

8 A In Mr. Scheperle's alternate BIP application, he devises a composite allocation factor

9   using a combination of class average demands, class 12 monthly non-coincident

10   peak demands and class three summer month non-coincident peak demands. At

11   each stage of the development of the allocation factor components, he subtracts the

12   demands associated with the previously determined component(s) from the total so

13   as to avoid double counting. The resulting factor is applied to all generation fixed

14   costs.

15   Because of the way that the BIP allocation factor was constructed in this case,

16   the end result is comparable to traditional allocation methods such as the A&E

17   method. Accordingly, while I disagree with the fundamental premise of BIP methods,

18   Mr. Scheperle has implemented it in this case in a way that produces results

19   consistent with generally accepted allocation methods.

1   Q   HOW HAS STAFF CLASSIFIED GENERATION SYSTEM NON-FUEL O&M

2   EXPENSES?

3   A   With minor exceptions, Mr. Scheperle has essentially used the "expenses follow

4   plant" approach that I have used.

5   ## Symmetry of Fuel and Capital Cost Allocation

6   Q   DO YOU HAVE ANY DISAGREEMENT WITH THE ALLOCATION OF FUEL AND

7   VARIABLE PURCHASED POWER COSTS ON THE BASIS OF CLASS ENERGY

8   REQUIREMENTS, ADJUSTED FOR LOSSES?

9   A   In the context of traditional studies like coincident peak and A&E, I do not. However,

10   in the context of the non-traditional studies like A&P and others, which heavily weight

11   energy in the allocation of fixed or demand-related generation costs, it is not

12   appropriate.

13   Q   PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO ALLOCATE ENERGY

14   COSTS IN THIS FASHION WHEN USING NON-TRADITIONAL STUDIES SUCH AS

15   A&P AND OTHERS.

16   A   These studies allocate significantly more generation fixed costs to high load factor

17   customers than do the traditional studies. In other words, the higher the load factor of

18   a class, the larger the share of the generation fixed costs that gets allocated to the

19   class. If the costs allocated to classes under these methods were divided by the

20   contribution of these classes to the system peak demand, or by the A&E demand, the

21   result is a higher capital cost per kW for the higher load factor classes, and a lower

22   capital cost per kW for the low load factor classes. Effectively, this means that the

23   high load factor classes have been allocated an above-average share of capital costs

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1   for generation, and the low load factor customer classes have been allocated a below

2   average share of capital costs.

3   Given these allocations of capital costs, it would not be appropriate to use the

4   same fuel costs for all classes. Rather, the fuel cost allocation should recognize that

5   the higher load factor customer classes should receive below average fuel costs to

6   correspond to the above-average capital costs (similar to base load units) allocated to

7   them, and the lower load factor classes should get an allocation of fuel costs that is

8   above the average, corresponding to the lower than average capital costs (i.e.,

9   peaking units) allocated to them.

10 Q   **WHY WOULD IT BE APPROPRIATE TO RECOGNIZE A LOWER FUEL COST**

11   **ALLOCATION TO THOSE CLASSES THAT ARE ALLOCATED A HIGHER**

12   **CAPITAL COST?**

13 A   It is not only appropriate, but it is essential if heavily energy-weighted allocations of

14   generation costs are employed. Failure to make this kind of distinction would charge

15   high load factor customers above-average capital costs, but not allow them to have

16   the related below-average energy costs; and charge the low load factor customers

17   below-average capital costs, yet still allow them to enjoy average fuel costs.

18 Q   **HAVE YOU PERFORMED ANY CALCULATIONS AND DEVELOPED A**

19   **SCHEDULE TO ILLUSTRATE THIS?**

20 A   Yes, I have. Please refer to page 1 of Schedule MEB-COS-R-1 attached to this

21   testimony. This schedule compares the capacity costs per kW and the energy costs

22   per kilowatthour ("kWh") across classes for the traditional A&E allocation method and

23   the A&P method. To establish a common framework of costs for the analysis, so as

1		to isolate the impacts just of allocation methodology, I used the total generation
2		capacity costs and total generation energy costs from Staff's cost of service study and
3		applied my allocation factors (traditional) as well as OPC's demand and energy
4		allocators to these total amounts. I then divided the results by the A&E capacity kW
5		and by the class megawatthours ("MWh").
6	Q	**PLEASE EXPLAIN WHAT THIS SCHEDULE SHOWS.**
7	A	The top part of the schedule shows that under traditional allocation methods the
8		capacity costs per kW and the energy costs per kWh allocated to each class are the
9		same.
10		The bottom part shows the allocation results under OPC's A&P method. Note
11		that the impact is to allocate significantly more capital costs, in fact, 21% more to the
12		LPS class and 47% more to the LTS class than under the traditional approaches,
13		which allocate average capacity costs to all classes. Note also that fuel costs per
14		kWh are essentially the same for all classes.
15		Page 2 of Schedule MEB-COS-R-1 graphically shows the skewing under the
16		A&P method.
17	Q	**YOU INDICATED THAT THE ENERGY COSTS PER KWH ARE THE SAME**
18		**UNDER THESE ALLOCATIONS. HOW DIFFERENT ARE THE ENERGY COSTS**
19		**OF THE DIFFERENT GENERATING FACILITIES?**
20	A	They are quite diverse. For example, the fuel cost for the Callaway nuclear unit is
21		about 0.75¢ per kWh, the base load coal plants have fuel costs in the range of 1.6¢ to
22		2.2¢ per kWh, the more efficient peaking units have fuel costs of 6¢ to 8¢ per kWh,
23		and other peakers have costs that are 10¢ per kWh to 18¢ per kWh. (Note: These

1   fuel costs are taken from Ameren Missouri's 2011 FERC Form 1 report.) Obviously, if

2   some classes are allocated higher capacity costs than others, they should be entitled

3   to at least an above-average share of the energy output from the higher capital cost,

4   more fuel efficient, base load type generating units, which would make their fuel cost

5   per kWh lower than average. The A&P allocation method advanced by OPC does

6   not recognize this correspondence, and as a result over-allocates costs to high load

7   factor customers.

8 Q **WHAT SHOULD BE CONCLUDED FROM SCHEDULE MEB-COS-R-1?**

9 A This schedule clearly demonstrates that the non-traditional methods like A&P are

10   highly non-symmetrical. They burden high load factor classes with above-average

11   capacity costs, but do not allow them to benefit from the lower cost of energy that

12   goes with the higher capacity costs. No theory supports this result and these studies

13   should be rejected.

14   **REVENUE ALLOCATION PROPOSALS**

15 Q **WHAT INTERCLASS REVENUE ALLOCATION DOES OPC RECOMMEND?**

16 A Ms. Meisenheimer indicates at page 17 of her testimony that she believes the

17   Residential class and the Small General Service ("SGS") class are close enough to

18   system average that they should not be subject to a revenue neutral increase. She

19   does not provide any recommendations for other customer classes. From this, I

20   assume that she does not propose to give weight to the results of her cost of service

21   studies and is supporting an equal percentage increase for all classes.

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| 1 | Q | WHAT REVENUE ALLOCATION PROPOSAL IS MADE BY STAFF? |

2 A As indicated at page 22 of Staff's "Rate Design and Class Cost-of-Service Report"

3 Staff recommends revenue neutral increases of 1% to the Residential class and 3%

4 to the Lighting class, and an approximate 1% decrease to other customer classes.

5 Any overall increase in revenues granted to Ameren Missouri would then be allocated

6 as an equal percentage to all classes.

7 Q DO YOU AGREE WITH STAFF'S RECOMMENDED REVENUE ALLOCATION

8 PROPOSALS?

9 A No. I disagree in two respects. First, the adjustment of 1% to Residential customers

10 and a 1% decrease to other customers, is far too modest to meaningfully adjust for

11 the wide differences in rate of return.

12 Second, Staff does not make a separate provision for the substantial new

13 additional costs associated with EE (the MEEIA-related costs and the pre-MEEIA

14 costs that are being amortized) in its revenue allocation formula. This is extremely

15 important because the identified EE revenue requirement as a percent of revenues

16 varies from 5.0% for the Residential class to 0% for the LTS class and the Lighting

17 class. The assignable amounts are 5% of revenues for the Residential class, 2.2% of

18 revenues for the SGS class, 4.3% of revenues for the Large General Service

19 ("LGS")/Small Primary Service ("SPS") class, 4% of revenues for the LPS class, 0%

20 for the LTS class and 0% for the Lighting class.

21 Q WHY ARE NONE OF THESE COSTS ASSIGNABLE TO THE LTS CLASS?

22 A In accordance with the opt-out provisions of the MEEIA legislation, as implemented in

23 the Commission's rules, customers meeting certain qualifications are permitted to

| 1 | | opt-out of and not participate in utility sponsored EE programs. The LTS customer |
| 2 | | has exercised that opt-out provision. |

3	Q	HAVE CUSTOMERS IN OTHER CLASSES ALSO OPTED OUT?
4	A	Yes. Certain customers in other classes, including customers in the SGS, LGS, SPS
5		and LPS classes, also have exercised the opt-out provision.

6	Q	WITH AN ACROSS-THE-BOARD INCREASE, OR WITH ONLY A MINOR COST OF
7		SERVICE ADJUSTMENT, WOULD OPT-OUT CUSTOMERS IN THE LPS CLASS,
8		FOR EXAMPLE, BE BURDENED WITH THE FULL AMOUNT OF THE EE COSTS
9		ASSIGNABLE TO THE LPS CLASS?
10	A	No, for two reasons. First, the share of EE costs properly assignable to this class
11		equates to 4.0% of its present revenues, which is essentially equal to the total costs
12		for all classes divided by the revenues from all classes. Second, within the LPS class
13		there is a specific provision whereby only customers who are participating in EE
14		programs pay for the costs of those programs by means of a special rate surcharge.
15		Customers who have opted out do not pay these costs, and thus would see rates that
16		are approximately 4% lower than customers who do not opt out. This is how the opt-
17		out provision is intended to work.

18	Q	COULDN'T THIS APPROACH ALSO WORK FOR THE LTS CLASS?
19	A	No. The LTS class has only one customer, and that customer has opted out. Any
20		amount associated with EE that is allocated to the LTS class would have to be paid
21		by the one customer in the class. There is not a customer that has not opted out, so

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1   all costs that are effectively allocated to the LTS class are paid by this customer . . .

2   who has opted out!

3   If the rate increase is allocated across the board (as proposed by Ameren

4   Missouri), or nearly across the board as proposed by Staff, the LTS customer who

5   has opted out of the EE program would still be charged the average cost (about 4%

6   of revenues) for a program that it has opted out of. This is clearly wrong, inconsistent

7   with the spirit of the MEEIA legislation and the Commission rules implementing

8   MEEIA, and would deny this customer the benefit of the opt-out provision.

9 Q **IN CASE NO. EO-2012-0142, AMEREN MISSOURI'S MEEIA PROCEEDING,**

10   **WHEN THE INDIVIDUAL RATE SCHEDULE COMPONENTS RELATED TO MEEIA**

11   **PROGRAMS WERE DETERMINED, WERE ANY COSTS ALLOCATED TO THE**

12   **LTS CLASS?**

13 A   No. In the MEEIA case, costs related to the new EE programs were assigned and/or

14   allocated (as appropriate) to the individual customer classes based on program costs

15   and estimated throughput reductions. These determinations in the MEEIA case

16   respected the opt-out provision and, accordingly, no program costs or throughput

17   disincentive component, were allocated to the LTS class. This case was resolved by

18   a Unanimous Stipulation that included Ameren Missouri, Commission Staff, OPC and

19   MIEC among the signatories.

20 Q **IS EE DIFFERENT FROM OTHER COSTS?**

21 A   Yes, it is materially different in its nature, and its impact on customers.

| 1 | Q | **PLEASE EXPLAIN.** |

2 A The primary beneficiary of any EE service is the customer who receives the incentive

3   or service of an EE program directly. As a result, this customer will experience a

4   reduction in the quantity of electricity through the meter which, of course, directly

5   reduces the amount of the electric bill. All of this benefit, i.e., 100%, accrues to the

6   customer receiving the EE service.

7   Unlike other costs, such as fuel, generation and transmission that are used to

8   serve all customers, EE costs are customer-specific in their application, and the

9   collection of EE costs must recognize that fact.

10 Q **IN THE SHORT RUN, WHO BENEFITS?**

11 A In the short run, only those customers who participate in the programs have the

12   possibility of being better off. They would be better off only if the savings that they

13   experience in their electric bill is more than the sum of their directly incurred costs

14   plus the demand-side, or EE, charges that they would pay to have Ameren Missouri

15   provide these services.

16 Q **WHAT ARE THE EXPECTATIONS IN THE LONG RUN FOR CUSTOMERS NOT**

17   **PARTICIPATING IN EE PROGRAMS?**

18 A As indicated by evidence supplied by Ameren Missouri in Case No. EO-2012-0142,

19   and presented as Schedule 5 to my rebuttal testimony in that proceeding, the EE

20   program will cause rates to be higher than they would have been had the programs

21   not been implemented and instead the utility had pursued supply-side resources.

22   Therefore, customers who are not receiving the direct benefit by participating in

1 Ameren Missouri's EE programs, will not benefit from them, and in fact will be worse

2 off.

3 Q **FOR THE LTS CLASS WHAT IS THE BOTTOM LINE ON THE EE ISSUE?**

4 A Because the LTS customer has opted out of EE programs, the percentage increase

5 to this class must be at least 4.0 percentage points less than the system average

6 increase in order to ensure that this customer is not charged part of the costs of the

7 EE programs that it has opted out of.

8 Q **CAN YOU ILLUSTRATE WITH AN EXAMPLE?**

9 A Yes. If the overall increase were 8%, the increase to the LTS class should not be

10 more than 4%. If the overall increase is 10%, the LTS class increase should not be

11 more than 6%.

12 Q **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

13 A Yes, it does.

Ameren Missouri

Docket No. ER-2012-0166

Customer Class Generation Capacity Costs Per kW
And Energy Costs Per kWh Under Traditional Methods
As Compared to OPC Proposal

MIEC COST OF SERVICE STUDY

Customer Class	Traditional Avg. & Excess CCOS			
	Capacity Rev Req.		Energy Rev Req.	
	Capacity Costs $ per kW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	141		1.62	
Res	141	0%	1.62	0%
SGS	141	0%	1.62	0%
LGS/SPS	141	0%	1.62	0%
LPS	141	0%	1.62	0%
LTS	141	0%	1.62	0%
Lighting	141	0%	1.62	0%

OFFICE OF PUBLIC COUNSEL COST OF SERVICE STUDY

Customer Class	OPC Avg. and Peak CCOS			
	Capacity Rev Req.		Energy Rev Req.	
	Capacity Costs $ per kW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	141		1.62	
Res	126	-11%	1.63	0%
SGS	133	-6%	1.63	0%
LGS/SPS	151	7%	1.63	0%
LPS	171	21%	1.63	0%
LTS	207	47%	1.63	0%
Lighting[1]	N/A	N/A	N/A	N/A

[1] OPC Cost of Service Study did not allocate costs to the Lighting class.

Ameren Missouri
Docket No. ER-2012-0166
Illustration of Skewed Allocation of Capital Costs and Energy Costs Under OPC's Allocation Proposal

Chart 1: Percent of Average Capacity Cost per kW — RES 89, SGS 94, LGS/SPS 107, LPS 121, LTS 147, with a line indicating Average Capacity Cost at 100.

Chart 2: Percent of Average Variable Cost per kWh — RES 100, SGS 100, LGS/SPS 100, LPS 100, LTS 100, with a line indicating Average Variable Cost at 100.