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-2014-0258
Date Testimony Prepared:	January 16, 2015

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 Its Revenues for Electric Service	**)))))**	**Case No. ER-2014-0258**

Rebuttal Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation and Rate Design

On behalf of

Missouri Industrial Energy Consumers

January 16, 2015

BRUBAKER & ASSOCIATES, INC.

Project 9913

**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 Its Revenues for Electric Service	)))))	**Case No. ER-2014-0258**

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 schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0258.

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 15th day of January, 2015.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2015
Commission # 11024862

Tammy S Klossner
Notary Public

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

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A Yes. I have previously filed direct testimony on class cost of service, revenue allocation and rate design issues presented in this proceeding.

Q ARE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN YOUR PRIOR TESTIMONY?

A Yes. This information is included in Appendix A to my revenue requirement direct testimony filed December 19, 2014.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"), including Noranda Aluminum, Inc. ("Noranda").

INTRODUCTION AND SUMMARY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A In my rebuttal testimony I will address the cost of service and revenue allocation proposals put forth by the Staff of the Missouri Public Service Commission ("Staff") and the Office of Public Counsel ("OPC"). I also will comment briefly on certain proposals made by the Missouri Department of Economic Development, Division of Energy.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A They may be summarized as follows:

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

2. OPC's proposal to allocate all of the revenue from off-system sales ("OSS") using a demand allocation has previously been rejected by the Missouri Public Service Commission ("Commission") and should continue to be rejected in this case. OPC compounds the error by failing to recognize that 100% of the energy costs associated with OSS has been allocated to customers on an energy basis. Allocating the costs on an energy basis, and 100% of the revenues on a demand basis, creates a significant mismatch, and materially over-allocates costs to the large primary service ("LPS") and the large transmission service ("LTS") customer classes. This error affects both the A&P study and OPC's version of the Average and Excess - 4 NCP ("A&E - 4 NCP).

3. Another deficiency in OPC's studies, both their A&P study and their version of the A&E - 4 NCP study, is that OPC has failed to allocate any portion of the distribution system on the basis of the number of customers or weighted number of customers. This is at odds with conventional allocation procedures, and is inconsistent with Commission precedent. It materially over-allocates costs to the LPS customer class.

4. The Commission Staff has offered three cost of service studies, all of which are outside the mainstream, conflict with prior commission rulings and contain deficiencies. None of them should be adopted.

5. Staff's Detailed Base-Intermediate-Peak ("BIP") study not only is theoretically incorrect but is full of implementation errors. Staff puts too much capacity in the

base category, arbitrarily adjusts the costs of intermediate plants downward by shifting some of the cost to the base load category, and ignores the cost of approximately 25% of Ameren's capacity when performing its calculations.

6. Staff's Modified BIP study develops capacity allocation factors similar to the A&E - 4NCP methodology, but contains significant mis-allocations of OSS margins, and a flawed allocation methodology for administrative and general expenses ("A&G").

7. Staff's Market Price study substitutes market prices of energy directly into the allocation equation, and completely ignores the actual embedded costs of energy and capacity when performing its study. It is based on a mis-characterization of the operation of the Midcontinent Independent System Operator, Inc. ("MISO"), and distorts the relationship between fixed costs and variable costs.

8. Staff essentially has allocated the estimated margin from OSS on the basis of class demands. As is the case with OPC's treatment, this is contrary to explicit findings of the Commission in prior Ameren Missouri and Kansas City Power & Light Company ("KCPL") cases that these are non-firm sales and should be allocated among classes using the class energy allocation.

9. Staff's studies are also flawed because the allocation of A&G expenses is on the basis of other previously allocated operation and maintenance expense that includes fuel. It is conventional to exclude fuel from the base used to allocate A&G expense because fuel (and purchased power) itself has little impact on A&G expense. The failure to exclude fuel when developing the allocation factor for A&G expense results in an over-allocation of costs to both the LPS and LTS customer classes, and should be rejected.

10. The recommendations of the Missouri Department of Economic Development, Division of Energy ("DED"), to require mandatory participation in Ameren Missouri's administered energy efficiency programs as a requirement for participation in economic development programs should be rejected as unsupported and counter-productive.

CLASS COST OF SERVICE ISSUES

Q HAVE YOU REVIEWED THE STAFF RATE DESIGN AND CLASS COST OF SERVICE REPORT ("STAFF REPORT") AND THE TESTIMONY OF OPC WITNESS GEOFF MARKE?

A Yes.

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

A Yes, I do. I disagree with the methods which OPC has 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.

I also have significant disagreements with all three of the alternative studies presented by Commission Staff, both with respect to the treatment of generation facilities and costs, as well as the allocation of a number of other cost of service elements.

OPC's Study

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

A OPC's recommended method is an A&P allocation method. In particular, OPC 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 only about 41% weighting to the contributions to the four monthly coincident peaks, and 59% weighting to annual energy consumption.

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

A No. While OPC explains the basis for the use of the four peaks, it does not explain or attempt to justify why this particular averaging method is appropriate for Ameren Missouri.

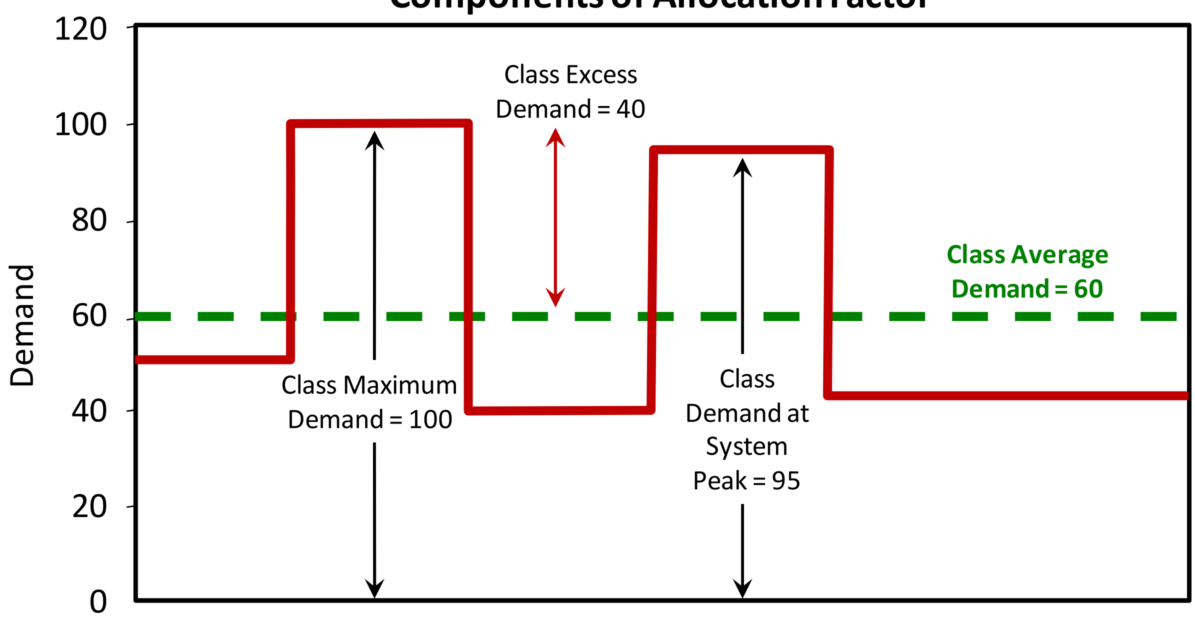
Q HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE AVERAGE AND EXCESS ("A&E") METHODOLOGY THAT YOU AND AMEREN MISSOURI USED IN YOUR CCOS STUDIES, AND WHICH THE COMMISSION HAS PREVIOUSLY ADOPTED?

A As noted above, OPC's A&P allocator is constructed by multiplying each class's percentage energy responsibility factor (average demand) times the system load factor, and adding that result to each class's percentage contribution to the 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 a major 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 25 of my direct testimony on cost of service, 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.)

OPC'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[1] 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.

[1]The weighting is actually 59% to energy and 41% to demand, making matters worse.

Q HAS THE COMMISSION PREVIOUSLY RULED ON OPC'S PROPOSED METHOD?

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

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

A No, it is not. As noted above, this allocation gives more weighting to annual energy consumption than to 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 heavy 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 over half of these costs on annual energy consumption.

Q HOW DID MR. MARKE ALLOCATE THE REVENUES AND MARGINS FROM OSS?

A He allocated all of the revenues from OSS (not just the margin) using the production demand allocation factor. There are two primary problems with this approach. First, the margin on OSS (which is included in the OSS revenue figure) should not be allocated on a demand basis. Rather, because these are largely non-firm sales, they should be allocated on a kWh basis, as this Commission has found on previous occasions.

Q PLEASE ELABORATE ON WHEN THE COMMISSION HAS FOLLOWED THE PRACTICE OF ALLOCATING OSS REVENUES, INCLUDING THE MARGIN, USING THE AN ENERGY ALLOCATION FACTOR.

A This Commission has held in a prior KCPL case (ER-2006-0314) and a prior Ameren Missouri case (ER-2010-0036) that it is appropriate to allocate the margin earned from OSS on an energy basis.

> The only costs assigned to non-firm off-system sales is the fuel and purchased power costs – the variable costs – hence the appropriateness of using the energy allocator. This is consistent with the way KCPL itself allocates the costs relating to the energy portion of firm capacity contracts – using the energy allocator. The reason is simple – the energy allocator is used to allocate variable costs of fuel and purchased power costs relating to retail sales. Using the same rationale, the energy allocator is equally appropriate to use as the allocation factor for both energy of firm (as KCPL does) and non-firm off-system sales. (Report and Order, Case No. ER-2006-0314, December 31, 2006)

This is also the most commonly used approach in the industry, and should be used in this case.

Q DID MR. MARKE GO BEYOND JUST ALLOCATING THE MARGIN ON A DEMAND BASIS?

A Yes, he went far beyond that. Not only did he allocate the margin using a demand allocator, but he allocated the remainder of the revenues the same way. These remaining revenues (the vast majority of them) essentially are related to the fuel cost of producing the energy that is sold off-system, while the margin is the amount of revenue after covering the fuel cost. Mr. Marke's inconsistency is that he has allocated to customer classes all of the energy cost, including that used to generate OSS, on a kWh basis.

By allocating the costs on a kWh basis, and then crediting the revenues to cover the fuel cost back on a demand basis, he has materially over-allocated costs to high load factor customer classes. As just one example, in the A&E - 4 NCP study, the LTS class is allocated 10.87% of energy cost and 6.5% of generation demand-related costs. Considering the approximately $134 million of fuel cost associated with OSS, Mr. Marke's allocation in the A&E - 4 NCP study over-allocates these costs to the LTS customer class by almost $6,000,000.

Q DO YOU HAVE ANY DISAGREEMENT WITH HOW OPC ALLOCATED DISTRIBUTION INVESTMENT AND EXPENSES?

A Yes. When allocating distribution investment and related expenses, it is common practice to recognize a customer component as well as a demand component. The reason is that distribution facilities are used not only to meet customer loads, but must be in place in order to move the power from the transmission system to the homes and businesses who take service from the distribution system throughout the service territory. (This is explained in somewhat more detail in my direct testimony from page 11 to page 13.) Mr. Marke, on the other hand, ignores the customer-related component that is recognized by Ameren Missouri, by Commission Staff and by me in the cost of service study I filed in my direct testimony. Ignoring the customer component of the distribution system as OPC has done is outside the mainstream, at odds with Commission precedent and materially distorts the cost of service results because it ignores a significant factor that must be considered in electric system design and operations.

Q WHAT IS THE IMPACT OF THIS ALLOCATION?

A It is significant. In terms of the LPS class, OPC's allocation allocates an additional $50 million of investment cost to that class, which is nearly one-third more than the class is allocated using widely accepted allocation methods.

Q ARE YOU AWARE OF ANY PRECEDENT OR AUTHORITY FOR TOTALLY IGNORING THE CUSTOMER COMPONENT OF THE DISTRIBUTION SYSTEM?

A No, I am not.

Q DO BOTH OF OPC'S STUDIES, THAT IS THE A&P STUDY AND THE A&E - 4 NCP STUDY, SUFFER FROM THE SAME INFIRMITIES WITH RESPECT TO THE TREATMENT OF OSS, REVENUES AND MARGINS, AND THE TREATMENT OF DISTRIBUTION INVESTMENT AND EXPENSES?

A Yes. Both studies contain the same inappropriate allocations.

Q IN OPC'S A&P STUDY, HOW ARE ENERGY COSTS ALLOCATED?

A They are allocated to all customer classes in proportion to class energy usage.

Q IS THIS CONSISTENT WITH HOW THE A&P STUDY ALLOCATES CAPACITY COSTS?

A No. The A&P study, by giving a significant weighting to energy consumption when developing the demand allocation factor, disproportionately allocates capital cost to high load factor customers. High load factor customers receive an above-average allocation of capital costs, but still must pay the overall system average fuel cost.

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 like A&P and others, 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 NON-TRADITIONAL STUDIES SUCH AS A&P AND OTHERS.

A 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 costs for generation, and the low load factor customer classes have been allocated a below average share of capital costs.

Given these allocations of capital costs, 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 costs to correspond to the above-average capital costs (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 costs (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 heavily energy-weighted allocations of generation costs are employed. Failure to make this kind of distinction would charge high load factor customers above-average capital costs, but not allow them to have the related below-average energy costs; and charge the low load factor customers below-average capital costs, yet still allow them to enjoy average fuel costs.

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-1 attached to this testimony. This schedule compares the capacity costs per kW and the energy costs per kWh across classes for the traditional A&E allocation method and the A&P 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 Ameren Missouri's cost of service study and applied my allocation factors (traditional) as well as OPC's demand and energy allocators to these total amounts. I then divided the capacity costs by the A&E capacity kW, and the energy costs by the class MWh.

Q PLEASE EXPLAIN WHAT THIS SCHEDULE SHOWS.

A The top part of the schedule shows that under traditional allocation methods each class has the same capacity costs per kW, and each class has the same energy cost per kWh.

The bottom part shows the allocation results under OPC's A&P method. Note that the impact is to allocate significantly more capital costs, in fact, 19% more to the LPS class and 41% more to the LTS class than under the traditional approaches, which allocate average capacity costs to all classes. Note also that fuel costs per kWh are essentially the same for all classes.

Page 2 of Schedule MEB-COS-R-1 graphically shows the skewing under the A&P method.

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 0.90¢ per kWh, the base load coal plants have fuel costs in the range of 2.0¢ to 2.6¢ per kWh, the more efficient peaking units have fuel costs of 4¢ to 10¢ per kWh, and other peakers have costs that are as much as $4.00 per kWh. (Note: These fuel costs are taken from Ameren Missouri's 2013 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. The A&P allocation method advanced by OPC does not recognize this correspondence, and as a result over-allocates costs to high load factor customers.

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

A This schedule clearly demonstrates that the non-traditional methods like A&P 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 studies should be rejected.

<u>Staff's Studies</u>

Q WHAT COST OF SERVICE STUDIES DID STAFF PROVIDE?

A Staff provided three different studies. It characterizes them as a Detailed BIP study, a modified BIP study and a Market Price study. Staff prefers the Detailed BIP study and that appears to be the primary basis for its recommendations.

Q PLEASE DESCRIBE GENERALLY THE DETAILED BIP STUDY.

A With this method, the fixed costs associated with base load generation essentially are allocated on a measure of class energy consumption. The intermediate plants are allocated as a function of class 12 monthly coincident peaks minus base demands. Facilities identified as peaking facilities are allocated on class four summer coincident peak demands reduced by the base and intermediate demands.

Q IS THE BIP STUDY METHODOLOGY ACCEPTED IN THE INDUSTRY?

A No, it is not. The BIP method first surfaced circa 1980 as an approach that some thought might be useful when trying to develop time-differentiated rates. However, the BIP method never caught on and is only infrequently seen in regulatory proceedings. The BIP method is certainly not among the frequently used mainstream cost allocation methodologies, and lacks precedent for its use.

Q WHAT SEEMS TO BE THE FUNDAMENTAL TENENT OF THE BIP METHOD?

A Staff does not say, but on page 16 of the Staff Report it says that the attempt is to determine the intended use of specific plant investments. By choosing to allocate 100% of the investment (fixed costs) associated with base load plants essentially on the basis of class energy, Staff effectively is assuming that investment in base load plants is not caused by demands and that these plants don't have a capacity cost. These are assumptions that we all know are false. All plants have a capacity cost, and provide capacity value as well as supplying energy. It appears from Staff's studies that about 66% of total generation fixed costs are allocated on the basis of class energy consumption.

Q PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT BASE LOAD PLANTS ARE ALLOCATED "ESSENTIALLY" ON THE BASIS OF CLASS ENERGY.

A In Staff's Detailed BIP study, 100% of the fixed costs associated with plants designated as base load are allocated to customer classes using the customer class energy requirement factor as the basis for the allocation. By using the energy allocation factor, Staff does not include any consideration of the times that energy is consumed (i.e., when demands occur), and would therefore attribute the same capacity cost to a customer that takes all of its load at the system peak hour as it would to a class with the same amount of energy consumption taken steadily at the same amount every hour throughout the year. (Please see the discussion of demand versus energy costs at pages 13-16 of my direct testimony, including Figure 3 on page 15.)

Q DOES THE CONCEPT OF ALLOCATING BASE LOAD PLANT ON A MEASURE OF CLASS ENERGY MAKE SENSE IN LIGHT OF SYSTEM PLANNING CONSIDERATIONS?

A No. The BIP approach attempts to assign only one purpose for each class of plant. In reality, when systems are planned, the utility attempts to install that combination of generation facilities which, giving consideration to fixed costs and variable costs, is expected to serve the needs of all customers, collectively, on a least-cost basis. All plants contribute to meeting peak demands, and the failure to allocate the fixed costs associated with base load plants on a measure of peak demand produces a biased result that over-allocates costs to high load factor customers and under-allocates costs to low load factor customers.

Q DID THIS COMMISSION RECENTLY RULE ON THE USE OF DEMAND ALLOCATION METHODS THAT ARE HEAVILY DEPENDENT UPON THE ENERGY USAGE BY THE VARIOUS CUSTOMER CLASSES?

A Yes. In a recent Ameren Missouri electric rate case, Case No. ER-2010-0036, cost of service studies were offered wherein the allocation basis for fixed generation cost was a weighted average of class energy consumption and class contribution to peak demands. In ruling on the case, the Commission rejected these heavily energy-weighted methods.

Q IN THE AMEREN MISSOURI CASE, WHAT PERCENTAGE OF GENERATION FIXED COSTS WAS ALLOCATED ON ENERGY UNDER THESE PROPOSALS?

A About 55%.

Q IS THE ALLOCATION OF GENERATION CAPACITY COSTS MORE HEAVILY DEPENDENT UPON CLASS ENERGY CONSUMPTION UNDER THE BIP METHOD IN THIS CASE THAN WAS TRUE IN THE AMEREN MISSOURI CASE WHERE THE ENERGY BASED ALLOCATION WAS REJECTED?

A Yes, much more. It is almost 67% with BIP as compared to 55% in the Ameren case.

Q AT PAGE 16 OF THE REPORT, STAFF INDICATES THAT THE BIP METHOD IS DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS COST ALLOCATION MANUAL ("NARUC MANUAL"). DOES THE FACT THAT A GENERATION ALLOCATION METHOD IS MENTIONED IN THE NARUC MANUAL GIVE IT CREDIBILITY OR SUGGEST THAT IT IS ACCEPTED IN THE INDUSTRY?

A No.

Q PLEASE EXPLAIN.

A The fact that a particular generation allocation method is noted in the NARUC Manual simply means that the individuals who prepared the NARUC Manual included it because it had been recommended by participants in one or more rate cases. There are a number of allocation methods that are described in the NARUC Manual that are not commonly used and that have not found wide support in the industry. Staff's BIP allocator clearly falls into that category.

Q PUTTING ASIDE FOR THE MOMENT THE THEORETICAL PROBLEMS THAT YOU HAVE IDENTIFIED WITH RESPECT TO THE DETAILED BIP METHOD, ARE THERE SOME PRACTICAL OR IMPLEMENTATION ISSUES WITH STAFF'S STUDY?

A Yes. There are several. First, in the determination of how much capacity is base load, Staff simply divides Ameren Missouri's total annual retail energy sales by the 8,760 hours in the year to arrive at approximately 4,500 megawatts as the amount of capacity to be considered base load. Conceptually, it is generally regarded that in the BIP method the base load should be considered that load which is present at all times. In the case of the Ameren Missouri system, however, the retail load is less than the 4,500 megawatts calculated by Staff in 57% of the hours in the test year. Obviously, the amount of capacity Staff has identified as base load is much higher than the capacity required to serve the load at all times. This skews the costs into the base load category and, since it is allocated on energy, the result is an over-allocation of costs to high load factor customers.

Q ARE THERE OTHER IMPLEMENTATION ISSUES?

A Yes. According to the theory expressed by Staff, intermediate units should have a lower capacity cost than base load units. When Staff stacked up Ameren Missouri's generating units from the lowest generation cost to the highest, and made its "cut" between base load and intermediate load units, the Sioux units fell into the intermediate category. When Staff calculated the costs per kW of the Sioux units, the result was that the Sioux units have a higher capacity cost per kW than the base load units … completely at odds with Staff's theory.

Q WHY DID THIS OCCUR?

A One of the reasons for this is the recent addition of costly scrubbers to the Sioux units. This points up another problem, namely that of the vintage of addition of a unit. Because of inflation, changing rules and standards, etc., it can easily happen that a more recently installed intermediate or peaking unit is higher than the depreciated value of a base load unit installed some years ago. This phenomena has caused a distortion in the Staff's study and skews the results for reasons completely apart from the theory used by Staff to partition units into the different categories.

Q HOW DID STAFF DEAL WITH THIS ISSUE?

A Staff "fixed" the problem by arbitrarily removing, and ignoring, about $115 million of the cost of the Sioux scrubbers (classified into the intermediate category) from the development of the BIP Production Capacity allocators. The result of this adjustment reduces the intermediate categories allocation of production plant from 29% to 27%. The majority of this cost is picked up by the base load category increasing its allocated share of production plant from 64% to 66% This, of course, is totally without theoretical support and further increases the costs attributed to base load units, again to the detriment of high load factor customers.

Q HAVE YOU IDENTIFIED OTHER MAJOR IMPLEMENTATION PROBLEMS?

A Yes. When Staff stacks up Ameren Missouri's generating units on the basis of variable cost, there are approximately 2,500 megawatts of capacity that are in excess of customer load. In calculating the average cost per kW of the peaking units in the BIP formulation, Staff simply ignored the costs associated with these approximately 2,500 megawatts of generating units that were not "needed" under its theory of cost-causation and cost responsibility allocation.

Q HAVE YOU REVIEWED STAFF'S MODIFIED BIP STUDY?

A Yes. Staff's modified BIP study develops a single composite allocator to be applied to 100% of the fixed costs of all generating units taken together. In that respect, it is similar to the traditional A&E - 4NCP study. In fact, the way that Staff combines class loads to develop the composite allocation factor produces an overall demand allocation factor under the modified BIP study that is quite similar to the allocation factor under the A&E - 4NCP study.

Q DO YOU TAKE ISSUE WITH ANY PARTS OF THE MODIFIED BIP STUDY?

A Yes. First, I should note that the fact the demand allocation factors between the Modified BIP study and the A&E - 4NCP study are similar may be due in part to coincidence. The fact that I do not object more vigorously to the allocation factor in this study should not be interpreted as an endorsement of the study methodology.

Beyond the allocation issue, I disagree with Staff's treatment of OSS, and also with its allocation of A&G expenses.

Q WHAT IS YOUR ISSUE WITH RESPECT TO HOW STAFF HAS ALLOCATED OSS?

A Staff has allocated the portion of OSS revenues that it attributes to energy cost using an energy cost allocator (which is reasonable), but has allocated what it deems to be the "margin" on a demand basis. This treatment fails to recognize that the OSS revenues are essentially non-firm, and occur as a matter of opportunity, rather than as a matter of planning or obligation, and therefore these sales do not have an allocable capacity component to them. This is discussed previously in my testimony in connection with my review of the OCA class cost of service allocation assumptions. This same shortcoming is contained in each of Staff's cost of service studies.

Q HAVE YOU REVIEWED STAFF'S STUDY WHICH IT CALLS THE "MARKET PRICE" STUDY?

A Yes. Under the guise of expanding on cost issues that arose in Case No. EC-2014-0224, Staff develops and presents what it calls a "Market Price" cost allocation study.

Q DO YOU AGREE WITH STAFF'S CHARACTERIZATION?

A No, I do not. The costing analysis discussed in Case No. EC-2014-0224 was in the nature of avoidable costs and the role of market price in that determination. It was not used, and was not represented as a means, to determine how to allocate a utility's embedded cost of service.

Q HOW DOES STAFF DEVELOP ALLOCATIONS UNDER ITS MARKET PRICE METHOD?

A The first step in Staff's allocation is to multiply the hourly loads of each class times the hourly locational marginal price ("LMP") in each hour over a three-year period.[2] This total is then divided by three to develop an average. This average LMP amount is then taken to be a component of production cost for each customer class. Staff subtracts the total of the LMPs from its total embedded cost of the production function and allocates this residual to customer classes based on a three-year average of customer 4CP demands. The sum of the two pieces equals the cost allocated to each customer class.

The market price allocation loads up the costs on the energy side, and minimizes the costs on the demand side. Because the LMPs are higher than embedded energy cost, there is a disproportionately large allocation of these costs to high load factor customers. In fact, roughly two-thirds of the cost component are allocated on an energy basis, and only about one-third on a demand basis.

Staff inappropriately also uses this allocation for OSS revenues, for other MISO-related items, and for transmission plant.

Q IN ONE OF THE JUSTIFICATIONS FOR ITS PARTICULAR ALLOCATION OF OSS, STAFF STATES THAT MISO DISPATCHES CAPACITY (STAFF REPORT AT PAGE 28). IS THIS TRUE?

A No. Essentially, all generators make a price bid to MISO, and MISO selects which units are to run so as to clear the market based on input bids and load bids. The

[2]Curiouisly, the three-year period used (2011-2013) does not include any data during the test year, and is not normalized.

incurred fuel costs and the revenues received from OSS are a function of this market clearing activity, and not the result of any dispatch of a capacity by MISO.

Q DO YOU HAVE AN ISSUE WITH STAFF'S ALLOCATION OF A&G EXPENSE?

A Yes. I have an issue with Staff's allocation of A&G expense in each of its studies.

Q WHAT IS THE ISSUE?

A A significant portion of A&G expense is allocated to classes on the basis of other O&M expenses, which include significant amounts of fuel and purchased power expense. Fuel and purchased power expense do not give rise to the incurrence of A&G expense in proportion to the level of fuel and purchased power expense because these costs are largely generated externally, as opposed to the labor and other costs of maintaining the generation, transmission, distribution and other functions of the utility, which are internally incurred and do give rise to the occurrence of A&G expense.

Q STAFF HAS REFERRED TO THE NARUC MANUAL FOR CERTAIN ALLOCATIONS. DOES THE NARUC MANUAL CONTAIN A DISCUSSION OF THE ALLOCATION OF GENERAL PLANT AND A&G EXPENSES?

A Yes. Pages 105-107 of the January 1992 NARUC Manual discusses A&G expenses. I have attached these pages as Schedule MEB-COS-R-2. Note that the majority of A&G expenses are allocated on labor. Wherever the Manual refers to a more general category of expenses, note that the phrase "less fuel and purchased power" appears. This means that fuel and purchased power should be excluded from the allocations.

From a cost causation point of view, none of the salary expense, pensions and benefits, plant-related or other costs vary with energy consumption. This is why it is traditional to exclude fuel and purchased power from any allocation of A&G expenses and focus on the cost-causative nature for these expenses. That is what I have done; it clearly is not what Staff has done.

Q DID STAFF ALLOCATE A&G EXPENSE THE SAME WAY IN EACH OF ITS THREE STUDIES?

A Yes, it did.

Q SHOULD THE COMMISSION RELY UPON THE RESULTS OF STAFF'S COST OF SERVICE STUDIES?

A No. As noted previously, these studies are outside the mainstream, conflict with prior Commission rulings and contain inappropriate allocations. None of them should be adopted.

Q YOU HAVE NOTED THAT THE STAFF AND OPC METHODS PROPOSED IN THIS PROCEEDING ARE NOT USED IN OTHER JURISDICTIONS AND ARE NOT SUPPORTED BY PRECEDENT OR ACCEPTED IN THE INDUSTRY. WHAT IS THE SIGNIFICANCE OF THIS?

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. 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.

OTHER ISSUES

Q HAVE YOU REVIEWED THE DIRECT TESTIMONY OF WITNESS JANE LOHRAFF, WHO TESTIFIES ON BEHALF OF THE MISSOURI DEPARTMENT OF ECONOMIC DEVELOPMENT, DIVISION OF ENERGY?

A Yes.

Q WHAT IS THE CENTRAL TENENT OF MS. LOHRAFF'S TESTIMONY?

A As stated on page 2 of her direct testimony, the central tenent is to recommend that Ameren Missouri's Economic Development Rider ("EDRR") and Economic Re-Development Rider ("ERR") be modified to require "active" participation in Ameren Missouri's MEEIA program as a requirement for receiving EDRR or ERR benefits.

Q DO YOU AGREE WITH MS. LOHRAFF'S RECOMMENDATION?

A No, I do not. This recommendation is flawed for several reasons. First, it would require mandatory participation in a program without any demonstration that the energy efficiency measures offered by the utility are not already in place as a result of the customer's investment, or that if they are not in place, the offered programs are applicable to and would be cost-effective with respect to the particular customer seeking to participate in the EDRR or ERR program.

Q WHY IS THIS A PROBLEM?

A It obviously is a problem because if the customer already has implemented and is practicing energy efficiency to the extent cost-effective for the customer, forcing participation in a program which does not provide additional benefits would only burden the customer with excess cost, and reduce the attractiveness of the economic development programs. In addition, even if the customer has not pursued all energy efficiency programs which would be cost-effective for it, if the Ameren Missouri program does not offer measures or other assistance that would be applicable to and cost-effective for the customer, requiring such participation would be self-defeating, and simply would amount to a "give-back" of part of the economic development benefits for which the customer otherwise would be eligible.

Q DO YOU HAVE ANY OTHER COMMENTS WITH RESPECT TO MS. LOHRAFF'S RECOMMENDATION OF MANDATORY PARTICIPATION IN AMEREN MISSOURI'S MEEIA PROGRAMS?

A Yes. It is MIEC's position that the statutory language implementing MEEIA provides the criteria for customers to "opt-out" of utility-sponsored energy efficiency programs, and that the statutory authorization for the opt-outs trumps any potential "policy" principles that DED or any other state government entity may attempt to impose.

Q ON PAGE 7 OF HER TESTIMONY, MS. LOHRAFF REFERENCES TARIFFS OF NORTHERN INDIANA PUBLIC SERVICE COMPANY, WISCONSIN POWER AND LIGHT COMPANY, AND PACIFIC GAS AND ELECTRIC COMPANY FOR THE PROPOSITION THAT ENERGY EFFICIENCY INITIATIVES HAVE BEEN TIED TO ECONOMIC DEVELOPMENT RIDERS IN OTHER STATES. HAVE YOU HAD AN OPPORTUNITY TO REVIEW THIS TESTIMONY AND THE ATTACHED TARIFFS?

A Yes.

Q DO YOU BELIEVE THAT THE ATTACHED TARIFFS SUPPORT MS. LOHRAFF'S RECOMMENDATION TO REQUIRE PARTICIPATION IN AMEREN MISSOURI'S MEEIA PROGRAMS BY CUSTOMERS RECEIVING ECONOMIC DEVELOPMENT INCENTIVES?

A No. These tariffs clearly do not support that view.

Q PLEASE EXPLAIN.

A First, the Northern Indiana Public Service Company tariff that is attached to her testimony simply references "high-efficiency, end-use equipment and construction technologies." No mention whatsoever is made of mandatory participation in any energy efficiency program that may be conducted by Northern Indiana Public Service Company. Accordingly, this tariff does not support Ms. Lohraff's recommendation.

Next, the Wisconsin Power and Light Company tariff attached to her testimony simply states that the customer must meet with company representatives to identify economically viable energy efficiency and demand-side management opportunities. It also requires the customer to participate in or implement all economically viable programs or projects with a projected payback of five years or less. However, it does not require mandatory participation in Wisconsin Power and Light Company's energy efficiency programs.

The attached Pacific Gas and Electric Company tariff is even further removed from the issue at hand. It is a "Net energy Metering Service for City and County of San Francisco Municipal Loads served by Hetch Hetchy At-Site Photovoltaic Generating Facilities." This tariff simply relates to photovoltaic generating facilities operated by Hetch Hetchy, which is a hydro electric facility owned by the City of San Francisco, and is used to supply municipal loads. It does not even come close to requiring what Ms. Lohraff states that it requires.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DED'S PROPOSALS?

A My recommendation is that they be rejected because they are unsupported, and if implemented could be counter-productive.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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AMEREN MISSOURI

Case No. ER-2014-0258

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

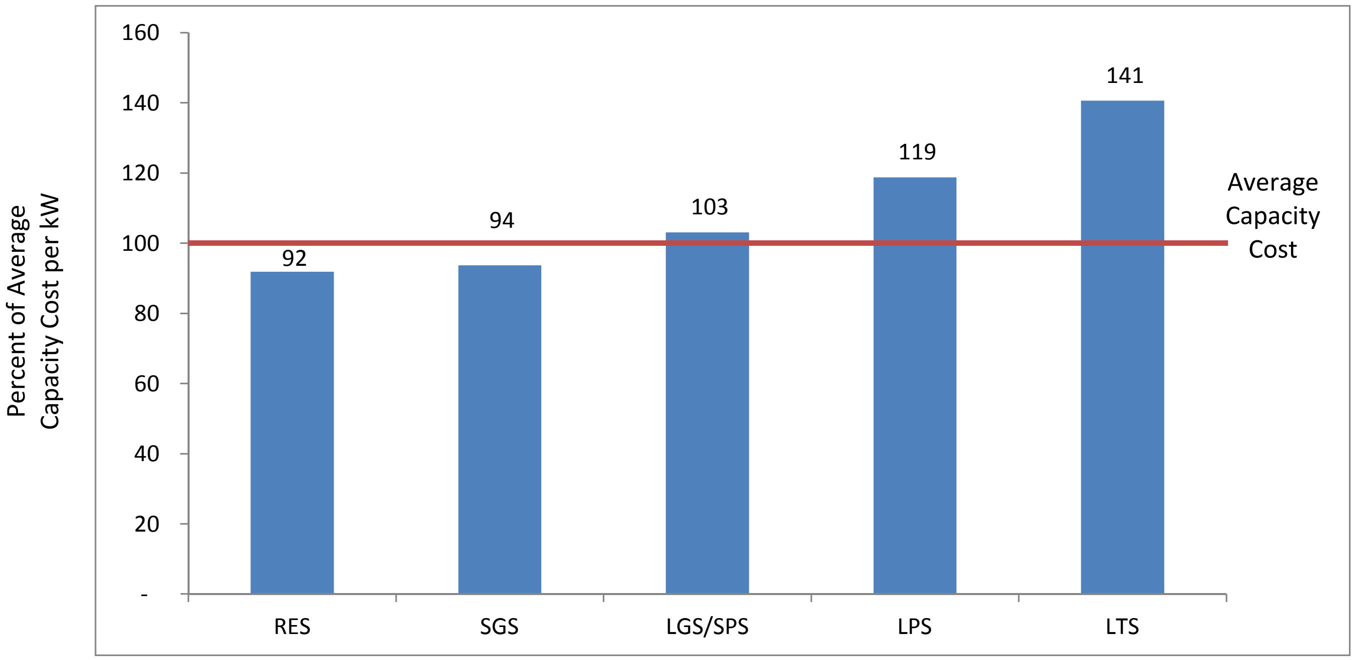
	Traditional Avg. & Excess CCOS			
	Capacity Rev Req.		Energy Rev Req.	
Customer Class	Capacity Costs $ per kW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	160		2.07	
Res	160	**0%**	2.07	**0%**
SGS	160	**0%**	2.07	**0%**
LGS/SPS	160	**0%**	2.07	**0%**
LPS	160	**0%**	2.07	**0%**
LTS	160	**0%**	2.07	**0%**
Lighting	160	**0%**	2.07	**0%**

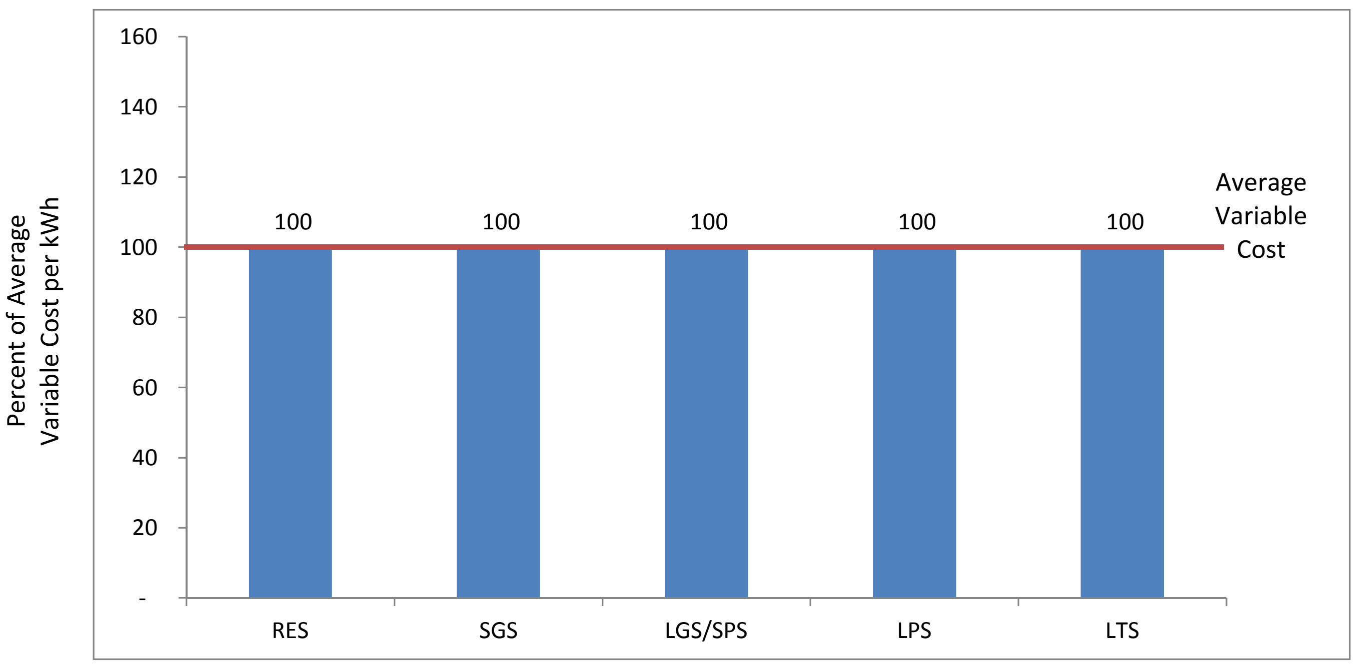
OFFICE OF PUBLIC COUNSEL COST OF SERVICE STUDY

	OPC Avg. and Peak 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	160		2.07	
Res	147	**-8%**	2.07	**0%**
SGS	150	**-6%**	2.07	**0%**
LGS/SPS	165	**3%**	2.07	**0%**
LPS	190	**19%**	2.07	**0%**
LTS	225	**41%**	2.07	**0%**
Lighting	83	**-48%**	2.07	**0%**

AMEREN MISSOURI
Case No. ER-2014-0258

Illustration of Skewed Allocation of Capital Costs and
Energy Costs Under OPC's Allocation Proposal





ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
Facsimile No. (202) 898-2213

Price: $25.00

CHAPTER 8

CLASSIFICATION AND ALLOCATION OF COMMON AND GENERAL PLANT INVESTMENTS AND ADMINISTRATIVE AND GENERAL EXPENSES

This chapter describes how general plant investments and administrative and general expenses are treated in a cost of service study. These accounts are listed in the general plant Accounts 389 through 399, and in the administrative and general Accounts 920 through 935.

I. GENERAL PLANT

General plant expenses include Accounts 389 through 399 and are that portion of the plant that are not included in production, transmission, or distribution accounts, but which are, nonetheless, necessary to provide electric service.

One approach to the functionalization, classification, and allocation of general plant is to assign the total dollar investment on the same basis as the sum of the allocated investments in production, transmission and distribution plant. This type of allocation rests on the theory that general plant supports the other plant functions.

Another method is more detailed. Each item of general plant or groups of general and common plant items is functionalized, classified, and allocated. For example, the investment in a general office building can be functionalized by estimating the space used in the building by the primary functions (production, transmission, distribution, customer accounting and customer information). This approach is more time-consuming and presents additional allocation questions such as how to allocate the common facilities such as the general corporate computer space, the Shareholder Relation Office space, etc.

Another suggested basis is the use of operating labor ratios. In performing the cost of service study, operation and maintenance expenses for production, transmission, distribution, customer accounting and customer information have already been functionalized, classified, and allocated. Consequently, the amount of labor, wages, and salaries assigned to each function is known, and a set of labor expense ratios is thus available for use in allocating accounts such as transportation equipment, communication equipment, investments or general office space.

II. ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include Accounts 920 through 935 and are allocated with an approach similar to that utilized for general plant. One methodology, the two-factor approach, allocates the administrative and general expense accounts on the basis of the sum of the other operating and maintenance expenses (excluding fuel and purchased power).

A more detailed methodology classifies the administrative and general expense accounts into three major components: those which are labor related; those which are plant related; and those which require special analysis for assignment or the application of the beneficiality criteria for assignment.

The following tabulation presents an example of the cost functionalization and allocation of administrative and general expenses using the three-factor approach and the two-factor approach.

Account Operation		Three-Factor Allocation Basis	Two-Factor Allocation Basis
920	A & G Salaries	Labor - Salary and Wages	Labor - Salary and Wages
921	Office Supplies	Labor - Salary and Wage	Labor - Salary and Wages
922	Administration Expenses Transferred-Credit	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
923	Outside Services Employed	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
924	Property Insurance	Plant - Total Plant [1]	Plant - Total Plant
925	Injuries and Damages	Labor - Salary and Wages[2]	Labor - Salary and Wages
926	Pensions and Benefits	Labor - Salary and Wages	Labor - Salary and Wages
927	Franchise Requirements	Revenues or specific assignment	Revenues or specific assignment

[1] A utility that self-insures certain parts of its utility plant may require the adjustment of this allocator to only include that portion for which the expense is incurred.

[2] A detailed analysis of this account may be necessary to learn the nature and amount of the expenses being booked to it. Certain charges may be more closely related to certain plant accounts than to labor wages.

Account Operation		Three Factor Allocation Basis	Labor-Ratio Allocation Basis
928	Regulatory Commission Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
928	Duplicate Charge-Cr.	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.1	General Advertising Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.2	Miscellaneous General Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
931	Rents	Plant - Total Plant[3]	Plant - Total Plant
Maintenance		**Three Factor *Allocation Basis***	**Labor-Ratio *Allocation Basis***
935	General Plant	Plant - Gross Plant	Labor - Salary and Wages

[3]A detailed analysis of rental payments may be necessary to determine the correct allocation bias. If the expenses booked are predominantly for the rental of office space, the use of labor, wage and salary allocators would be more appropriate.