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Issue:	Class Cost of Study, Revenue Allocation, Rate Design,
Witness:	Kavita Maini
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2016-0023
Date Testimony Prepared:	May 2, 2016

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	**File No. ER-2016-0023** Tariff No. YE-2016-0104

Rebuttal Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

May 2, 2016

MECG Exhibit No. 2 NP
Date 6-02-16 Reporter KF
File No. ER-2016-0023

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

NP

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area	))))	Case No. ER-2016-0023

STATE OF WISCONSIN)
) SS
COUNTY OF WAUKESHA)

AFFIDAVIT OF KAVITA MAINI

Kavita Maini, being first duly sworn, on her oath states:

1. My name is Kavita Maini. I am a consultant with KM Energy Consulting, LLC. having its principal place of business at 961 North Lost Woods Road, Oconomowoc, WI 53066. I have been retained by the Midwest Energy Consumers' Group ("MECG") in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2016-0023

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.

Kavita Maini

Subscribed and sworn to before me this ___ day of April 2016

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)	**File No. ER-2016-0023** Tariff No. YE-2016-0104

TABLE OF CONTENTS

		Page
I.	INTRODUCTION	2
II.	RECOVERY OF SC-P INTERRUPTIBLE CREDITS	3
III.	STAFF'S CLASS COST OF STUDY	6
IV.	ALTERNATIVE CLASS COST OF STUDY	16
V.	REVENUE REQUIREMENT ALLOCATION	24

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of The Company	)	**File No. ER-2014-0351** Tariff No. YE-2015-0074

Rebuttal Testimony of Kavita Maini

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. PLEASE STATE YOUR BUSINESS ADDRESS.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. ARE YOU THE SAME KAVITA MAINI WHO HAS PREVIOUSLY FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I filed direct testimony on behalf of the Midwest Energy Consumers Group ("MECG"). My direct testimony provided recommendations regarding: (a) class cost of service study, (b) an appropriate allocation of any rate increase, and (c) rate design for the Large Power and Schedule SC-P rate schedules.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address Staff's direct testimony as it pertains to: (a) Staff's recommendation to disallow recovery of the interruptible credits associated with the SC-P rate schedule and (b) Staff's class cost of service ("CCOSS") study and associated revenue allocation.

II. RECOVERY OF SC-P INTERRUPTIBLE CREDITS

Q. WHY DOES SCHEDULE SC-P RECEIVE AN INTERRUPTIBLE CREDIT?

A. Schedule SC-P consists of one customer, Praxair. Unlike the vast majority of Empire's customers which receive firm service, Praxair's service is interruptible. Praxair receives a credit for its willingness to have its service interrupted. Praxair's load is unique in that almost its entire load is interruptible (**____ ______**) and it can be interrupted with a 30 minute notice.[1] Praxair's interruptible load is over **____** of the Company's total interruptible load.[2] While the Schedule SC-P is labeled as a Special Contract, there is no special discount for load retention provide in this Schedule. Rather, this is simply another example of an interruptible rate schedule. The need for the SC-P rate schedule is because of the unique terms of the schedule. Specifically, Empire is allowed to interrupt Praxair's load more frequently (up to 13 curtailments events as opposed to 10 curtailments in the interruptible rider) and on much shorter notice than what is required under Empire's Interruptible Rider (30 minute notification as opposed to four hours). The shorter notification makes Praxair

[1] See response to OPC 5058.
[2] See response to OPC 5058 and 5062 HC

interruptible load more valuable and gives the Company the ability to react quickly to shortage situations.

Q. HOW IS THE RECOVERY OF INTERRUPTIBLE CREDITS TYPICALLY HANDLED IN OTHER JURISDICTIONS?

A. Interruptible credit related costs are typically considered to be prudent costs that are recovered by the utility from all firm load. This is because interruptible load helps to lower the utility's capacity obligations needed to comply with capacity margin or planning reserve margin requirements set by the North American Electric Reliability Corporation ("NERC") and followed by regional transmission organizations such as the Southwest Power Pool. The capacity obligations are required to maintain grid reliability.[3]

Q. WHAT IS THE ISSUE REGARDING COST ALLOCATION ASSOCIATED WITH SCHEDULE SC-P'S INTERRUPTIBLE CREDITS?

A. Commission Staff recommends that Empire not be allowed to recover the credits that Empire pays to interrupt Praxair's load. Staff's recommended approach is apparently based upon the faulty notion that other ratepayers do not receive a benefit associated with these credits.[4]

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[3] See example provided in my direct testimony, page 17

[4] See Commission Staff Revenue Requirement Report, Page 78

Q. HAS COMMISSION STAFF PREVIOUSLY ACKNOWLEDGED THE VALUE OF INTERRUPTIBLE LOAD AND RECOMMENDED RECOVERY OF THE INTERRUPTIBLE CREDIT COSTS?

A. Yes. Strangely, while Staff disallows recovery of the interruptible credits associated with the SC-P rate schedule, Staff seems to have provided for the recovery of interruptible credits for Empire's customers that are served under the Rider IR (Interruptible Service). Furthermore, in a recent KCPL case, Staff also allowed for recovery of interruptible credits. Specifically, Staff stated the following:

> **PLCC/MPower:** Peak load curtailment credits are paid to customers that agree to curtail a portion of their peak load when requested by KCPL. ***These discounts are assumed to be a benefit to all ratepayers and thus are not excluded from the determination of KCPL's revenues.***[5]

Finally, Company witness Scott Keith testified in the last case that the "interruptible arrangement with Praxair has been around for years, and in past Empire rate cases has been included in Empire's revenue requirement."[6] Thus, it appears that Staff is being inconsistent in its treatment of the SC-P interruptible credit costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SC-P INTERRUPTIBLE CREDITS?

A. My recommendation is that Empire should be allowed to include the costs of the SC-P interruptible credit in its revenue requirement and to allocate these costs to its firm load customers. Having interruptible load benefits all customers and therefore, recovering these costs from all firm load is reasonable. Such an approach is conventional and

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[5] See Commission Staff Revenue Requirement Cost of Service Report in ER-2010-0355 (emphasis added).
[6] See Scott Keith Rebuttal Testimony, Case No. ER-2014-0351, at page 11.

typically applied in other jurisdictions. The interruptible credit provided to Praxair is not a load retention discount, but compensation for providing interruptible service.

III. STAFF'S CLASS COST OF STUDY ("CCOSS")

Q. WHAT IS THE FOCUS OF YOUR DISCUSSION REGARDING STAFF'S CCOSS?

A. A class cost of service study concerns the allocation of all of the utility's costs, revenues and rate base. That said, my focus here is on the method that Staff used to allocate: (1) production related fixed costs; (2) fuel costs; (3) non-fuel operations & maintenance ("O&M") costs and (4) purchased power capacity costs. My decision not to comment on other aspects of Staff's class cost of service study should not imply agreement with the methodology used by Staff.

I. FIXED PRODUCTION PLANT ALLOCATION

Q. WHAT ARE FIXED PRODUCTION PLANT COSTS?

A. Fixed production plant costs are the capital costs associated with the utility's investment in generating plants. This includes investment in nuclear, coal, steam, hydro and wind generation. As the name implies, fixed costs do not vary with the amount of electricity generated by these units. These costs do not include the variable costs of production, primarily fuel, that vary with the amount of electricity generated.

Q. WHAT METHOD DID STAFF USE TO ALLOCATE FIXED PRODUCTION PLANT COSTS?

A. Staff characterized their method as a detailed Base Intermediate Peak ("BIP") method to allocate fixed production plant to the classes.

Q. **PLEASE EXPLAIN STAFF'S BIP METHOD.**

A. Staff attempts to first classify fixed production plant investment as baseload, intermediate or peaking based on Staff's perception of the intended use of the investment. Using customer class load data, Staff then develops three <u>non-weighted</u> components to calculate what it calls the BIP Installed Capacity Allocator by class:

- Base load generation costs are allocated to classes based on average demand. Effectively, average demand is the same as class energy usage;
- Intermediate generation costs are allocated on the basis of 12CP demand minus average demand; and
- Peaking generation costs are allocated on the basis of 4CP minus intermediate demand.

Q. **WHAT ARE YOUR CONCERNS ABOUT STAFF'S BIP APPROACH?**

A. I have the following concerns about the BIP study approach which are described in detail below[7]:

- It lacks acceptance in the industry and its replicability is questionable given the advent of SPP's Integrated Marketplace;

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[7] Staff's use of the BIP methodology has been the subject of rejection and criticism from both customers and utilities. See, Cooper (AmerenUE) Rebuttal, Case No. ER-2011-0028, page 6; Brubaker (MIEC) Rebuttal, Case No. ER-2011-0028, pages 9-10; Cooper (AmerenUE) Rebuttal, Case No. ER-2012-0166, page 7; Brubaker (MIEC) Rebuttal, Case No. ER-2012-0166, pages 11-12; Warwick (AmerenUE) Rebuttal, Case No. ER-2014-0258, page 7; Brubaker (MIEC) Rebuttal, Case No. ER-2014-0258, pages 14-25; Overcast (Empire) Rebuttal, Case No. ER-2014-0351, pages 6-7; Maini (MECG) Rebuttal, Case No. ER-2014-0351, pages 10-12; Rush (KCPL) Rebuttal, Case No. ER-2014-0370, pages 46-47; Brubaker (MECG) Rebuttal, Case No. ER-2014-0370, pages 11-18.

- It is theoretically flawed and inconsistent with system planning in that the approach minimizes the need and value of capacity; and
- Staff's method also has implementation flaws that result in deviation from cost causation.

1. BIP's Lack of Acceptance in the Industry

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 meaningful precedent for its use.

Q. WHAT IS THE SIGNIFICANCE OF BIP'S PROPOSED METHOD NOT BEING ACCEPTED IN THE INDUSTRY?

A. Cost of service studies for electric systems have been performed for well over 50 years. This means that a significant amount of analysis 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, such as the BIP, bear a special burden of proving that they do a more accurate job of identifying cost-causation than do recognized methods. Here, as demonstrated below, it should be clear that the BIP method does a less accurate job of identifying cost-causation than the recognized method that I advocate and discussed later in my testimony.

Q. HAVE OTHER UTILITIES SERVING MISSOURI CUSTOMERS EXPRESSED CONCERNS ABOUT THE BIP APPROACH?

A. Yes, in its most recent case, Kansas City Power & Light witness Tim Rush essentially testified that the BIP approach can no longer be reasonably replicated given KCPL's participation in SPP's Integrated Marketplace. In fact, given the advent of the SPP Integrated Marketplace, KCPL has abandoned its use of the BIP. Specifically, KCPL stated:

> The Company has utilized the BIP method previously in Missouri. . . . The recent transition of the SPP to an Integrated Marketplace (IM) with centralized dispatch has raised some concern about the BIP allocator. To utilize the BIP allocator one must assign the generating units into base, intermediate, and peak groups based on their use. Prior to the IM market, the Company provided its own generation to meet its load requirements. With the introduction of the IM market, we no longer use our generation to meet the Company's load requirements, but instead sell generation into the SPP market and buy our load requirements for the SPP market. I believe the IM market change in impacts the suitability of the BIP method as the production allocation.[8]

2. <u>Theoretical Flaws Associated with Staff's BIP Approach</u>

Q. WHAT SEEMS TO BE THE FUNDAMENTAL BASIS FOR STAFF'S BIP METHOD?

A. Based on the Staff Report, the purpose of the BIP is to attempt to determine the intended use of specific plant investments.

[8] Rush Direct Testimony, Case No. ER-2014-0370, pages 46-47.

Q. WHAT IS THE FLAW IN STAFF'S EFFORT TO IDENTIFY THE "USE" OF PRODUCTION PLANT INVESTMENT?

A. The primary flaw is found in Staff's overvaluation of energy production while minimizing the value of capacity. By choosing to allocate 100% of base load investment on the basis of class energy, Staff is effectively assuming that investment in base load plants is not caused by system demands and that these plants don't have a capacity cost. These are faulty assumptions. All plants have a capacity cost, and provide capacity value as well as supplying energy.

When it contemplates the addition of a generating unit, the utility focuses primarily on its system peak (in kW's) and its current ability to meet that peak. As such, system planning is based on capacity needs. While these units have a high capacity value, Staff seeks to allocate the investment in these production plants primarily on the basis of the energy produced (in kWh's) by the plants. In fact, it appears from Staff's studies that about 74% of total generation fixed costs are allocated on the basis of class energy consumption.[9]

Q. PLEASE EXPLAIN WHY YOU SAY THAT STAFF HAS ALLOCATED BASE LOAD PLANTS ON THE BASIS OF CLASS ENERGY.

Table 1 shows Staff's allocation associated with baseload capacity costs and each class' share of energy consumption. As noted below, the relative percentage of each's class' energy consumption is exactly the same as the allocation of baseload investment.

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[9] $624.56 million of Empire's total investment in production plants ($848.95 million) is characterized as baseload capacity and allocated on the basis of class energy consumption. See Staff Rate Design Report, page 23

Table 1: Comparison of Baseload Generation Fixed Cost Allocators vs. Energy Allocator

	Total	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Baseload Capacity Cost Allocation	$ 624,559,240	$ 251,866,101	$ 47,877,560	$ 13,706,700	$ 56,402,413	$137,931,897	$ 101,583,759	$ 10,160,632	$ 99,024	$4,931,153
Class Percent of Total	100.00%	40.33%	7.67%	2.19%	9.03%	22.08%	16.26%	1.63%	0.02%	0.79%
MWhs @ Generator	4,364,751,802	1,760,189,460	334,598,439	95,788,915	394,171,193	963,953,919	709,929,832	71,008,904	688,845	34,422,243
Energy Allocator @ Generator	100.00%	40.33%	7.67%	2.19%	9.03%	22.08%	16.27%	1.63%	0.02%	0.79%

By relying entirely on energy, Staff does not include any consideration of the time when energy is consumed (i.e., when demands occur). Therefore, Staff attributes the same capacity cost to a customer class that consumes all of its energy at the system peak hour as it would to a class which consumes energy steadily at the same amount every hour throughout the year. For example, consider two classes, A and B. Both use the same monthly consumption at 292,000 KWh. However, Class A has a coincident peak demand of 500 KW (load factor of 80%) and Class B has a coincident peak demand of 1000 KW (load factor of 40%).[10] Therefore, Class B contributes twice as much capacity obligations. However, since Staff's method of allocating baseload capacity is entirely energy based, both of these classes would be assigned the same base load capacity cost. In reality though, Class A utilized the system more efficiently by consuming energy at a steady rate, whereas Class B consumed less energy but contributed more towards the utility's system peak.

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

[10] Coincident peak refers to the class' peak at the time that the utility experiences its system peak.

A. No. The BIP approach attempts to assign only <u>one</u> purpose for each class of plant – the production of electricity. In reality, when systems are planned, the utility attempts to install that combination of generation facilities which, given 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 towards meeting the system peak demands, and the failure to consider the capacity value of these plants produces a biased result that over-allocates costs to high load factor customers and under-allocates costs to low load factor customers.

The implied assumption here is that investment in base load generation is not caused by need for capacity to meet system peak. However, this assumption is flawed because the Company utilizes accredited capacity from all of the baseload plants to satisfy its capacity margin obligations required by NERC standards. Furthermore, the decisions to invest in production capacity, as reflected in the utility's integrated resource planning process, is driven primarily by system peak, not energy usage.

Essentially, by relying so heavily on class energy needs, Staff's minimizes the capacity needs of the plant. Once again, this is not consistent with how the system is planned. If the system were planned based primarily on energy production, then energy needs would be met primarily with wind generation (energy production, but very little capacity). System needs would be very rarely met with coal or nuclear units that provide capacity value. This is obviously not the case today. Utilities serving Missouri customers have a diverse mix of resources including nuclear, coal and natural gas generation. This is because they also provide capacity value. Staff's BIP methodology fails to capture this basic concept.

3. Implementation Flaws Associated with Staff's BIP Approach

Q. **ASIDE FROM THE FACT THAT THE BIP IS INCONSISTENT WITH SYSTEM PLANNING, ARE THERE ISSUES ASSOCIATED WITH STAFF'S IMPLEMENTATION OF THE BIP METHOD?**

A. Yes; in determining the amount of baseload demand used to allocate baseload capacity, Staff simply calculates the baseload demand by determining the average demand for each class. This is a flawed assumption because average demand (or energy usage / 8760) does not translate to base load demand. When applying the BIP method, base load usage is generally regarded as usage with a 100% load factor meaning that it is present all 8760 hours of the year. In Empire's case, however, the retail load is less than the 498 megawatts calculated by Staff in 58% 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 means that there is an over allocation of base load capacity costs than is appropriate which ultimately results in assigning a disproportionate amount of costs to high load factor classes.

Q. **DOES STAFF INCLUDE ALL CAPACITY IN CALCULATING ITS BIP INSTALLED CAPACITY ALLOCATOR?**

A. No; all the capacity that is included in the Company's rate base is not included. Staff seems to use the amount of capacity used to fulfill the energy requirements. Any remaining capacity beyond this amount is not considered in the calculation of the installed capacity allocator. In doing so, Staff simply ignored the costs associated with certain generating units that were not "needed" under its theory of cost-causation and cost responsibility allocation.

Q. WHAT DO YOU CONCLUDE FROM THE OBSERVATIONS REGARDING STAFF'S DETAILED BIP INSTALLED CAPACITY ALLOCATOR?

A. For all the reasons discussed above, I conclude that Staff's method of calculating the detailed BIP installed capacity allocator is inappropriately and heavily weighted towards energy usage. The results are therefore, biased towards allocating capacity costs to high load factor classes and away from low load factor customers.

<u>II. FUEL COST ALLOCATION</u>

Q. PLEASE COMMENT ON STAFF'S METHOD FOR ALLOCATING FUEL COSTS.

A. Staff also uses the baseload, intermediate and peaking categories to allocate fuel costs to classes. While this approach attempts to recognize that lower fuel costs should be allocated to classes that are allocated higher capacity cost,[11] there is a major flaw in Staff's method of calculating the BIP energy allocator. This flaw is attributable to the fact that Empire is a significant net purchaser from SPP's Integrated Marketplace ("IM"). As Staff's Revenue Requirement report indicates on page 83:

> In Staff's fuel model run, Empire generated $17.8 million in sales and purchased $41.6 million of energy through the IM, resulting in net purchased power expense of $23.8 million.

[11] In general, generating plants with higher investment costs also have lower variable costs. Similarly, generating plants with lower investment costs have higher variable costs.

Staff seems to assume that such a significant amount of purchased power costs should be allocated in the same manner as fuel costs from utility owned generation. No analysis appears to be conducted to demonstrate the time varied nature of these purchased power costs, the basis of segmenting these costs into base, intermediate and peaking, and to what extent they are similar or different from what Staff calculated from its BIP energy allocator.

Q. IS THE BIP APPROACH FOR CALCULATING ENERGY COSTS COMPATIBLE WITH THE SPP MARKET?

A. No, utilities participating in the market are no longer in control of dispatching their units to serve their own load. SPP manages this dispatch centrally in a least cost manner based on the load characteristics of the entire SPP footprint. Utilities' generation use is dependent on SPP's dispatch and therefore, attempting to segment the Company's generation into different types particularly when the Company is a net purchaser becomes even more subjective. This aspect makes it questionable to allocate capacity or energy costs using Staff's BIP approach.

3. OTHER STAFF ALLOCATION ISSUES

Q. WHAT ARE NON-FUEL OPERATIONS AND MAINTENANCE ("O&M") COSTS?

A. Non-fuel O&M costs are fixed in nature and generally labor related expenses. For more detail, see Staff Jurisdictional Allocator Workpapers in this docket.

Q. WHAT IS THE ISSUE REGARDING ALLOCATION OF NON-FUEL O&M COSTS?

A. Recognizing that these costs do not vary with the amount of electricity generated, they are typically regarded as demand-related costs and should be allocated in the same manner as capacity costs. That said, however, Staff appears to have developed another allocator in lieu of utilizing the allocator it developed to allocate capacity costs (see table on page 24 of Staff's Rate Design Report).

Q. WHAT IS THE ISSUE REGARDING THE ALLOCATION OF PURCHASED POWER CAPACITY COSTS?

A. In Staff's CCOSS, purchased power costs noted as "demand only" are classified as energy related. Since the purchased power is for demand or capacity, it should be classified as demand-related.

III. ALTERNATIVE CLASS COST OF SERVICE STUDY

Q. WHAT ARE THE DIFFERENT STEPS INVOLVED IN THE CCOSS PROCESS?

A. The three major steps are:

Functionalization: Various costs are separated according to function such as generation, transmission, distribution, customer service and administration.

Classification: The functionalized costs are classified based on the components of utility service being provided. As described by the NARUC Manual, the three principal cost classifications are demand costs (costs that vary with the KW demand imposed by the customer), energy costs that vary with energy or kWh that the utility provides), and customer costs (costs that are directly related to the number of customers served). See NARUC Manual page 20.

Allocation: Once the costs are classified as demand-related, energy-related or customer-related, they are then allocated to classes using the relevant demand, energy or customer allocators.

Each of these steps is very important because it sets the foundation for developing rates and sending accurate pricing signals. If costs are improperly functionalized, classified or allocated, they result in cross subsidies and inappropriate pricing signals in rate design.

Q. DID YOU PREPARE A CCOSS STUDY?

A. Yes; I ran the Staff CCOSS model with different allocators than what Staff used for fixed production costs, fuel costs, O&M and purchased power capacity costs. I discuss each of these below.

Q. WHAT IS THE PRIMARY DRIVER IN DETERMINING COST CAUSATION WITH RESPECT TO COSTS CLASSIFIED AS FIXED PRODUCTION PLANT?

A. The monthly system demand is the primary factor which drives production plant investment decisions. As such, class monthly system demand and its contribution to system peak should be the primary factor in allocating these costs.

Q. DID YOU ANALYZE EMPIRE'S SYSTEM LOAD?

A. Yes, I did. Figure 2 shows the system monthly peaks as a percent of overall annual system peak for the period used by Staff (October 2014-September 2015). This chart shows that the system peaked in January with the next highest peaks in June through August.

Figure 2: Monthly Peaks as a Percent of System Peaks[12]

Q. WHAT ALLOCATION METHODS WOULD BE REASONABLE IN ALLOCATING FIXED PRODUCTION PLANT RELATED COSTS?

A. Either the Coincident Peak Demand method or the Average and Excess ("A&E") Demand method would be a reasonable method for allocating fixed production plant costs.

In the Coincident Peak Demand method, the fixed production plant costs are allocated to rate classes on demand factors that measure the class contribution to system peak or peaks. As such, this methodology focuses entirely on peak demand without any consideration of energy.

[12] Data from response to OPC DR-5003

The A&E Demand method introduces some consideration of energy consumption. Specifically, this method consists of an average component (energy) and an excess component (demand). The average component is the average demand and represents energy usage at a 100% load factor. In other words, it is calculated by dividing the energy usage of each class by the number of hours in a year (8,760 for a non-leap year). The excess component is calculated as the difference between the customer group's maximum non-coincident peak or peaks and the average demand. The average component for each class is weighted by the load factor and the excess component for each class is weighted by 1-load factor.[13] The composite allocator is the sum of the weighted average and excess components.

The A&E approach considers the load profile of customer groups by incorporating the maximum demands, load factor and average energy use. While the average demand or energy portion measures the duration, the excess portion measures the variability of the load profile of a class. For example, as noted in the Commission decision in Docket No. ER-2010-0036 (pages 84-85):

> Some customer classes, such as large industrials, may run factories at a constant rate, 24 hours a day, 7 days a week. Therefore, their usage of electricity does not vary significantly by hour or by season. Thus, while they use a lot of electricity, that usage does not cause demand on the system to hit peaks for which the utility must build or acquire additional capacity. Another customer class, for example, the residential class, will contribute to the average amount of electricity used on the system, but it will also contribute a great deal to the peaks on system usage, as residential usage will tend to vary a great deal from season to season, day to day, and hour to hour.

Both the coincident peak and A&E methods are included in the NARUC manual and are compatible with least cost resource planning. In terms of developing the allocator, either

[13] See NARUC Manual, page 49,81-82

using the class coincident peaks during the peak months for the coincident peak method or utilizing class non-coincident peaks during the peak months would be reasonable approaches.

Q. WHICH ALLOCATION METHOD DO YOU RECOMMEND IN THIS CASE?

A. I recommend the A&E demand method which relies on the peaks experienced during June, July, August and January in this case. I would also note that the allocators using the 4CP coincident peak method, non-A&E methodology, were similar.

With respect to the non-coincident peaks, the four months of June-August and January represent the highest peak periods respectively and reflect cost causation regarding generation plant infrastructure decisions. These months drive the capacity needs for the system and were therefore used to determine the cost allocation to classes. Consistent with the method described in the NARUC manual, I calculated the excess portion using the non-coincident peaks from the four peaking months.

Q. ARE YOU AWARE OF OTHER UTILITIES THAT HAVE RECOMMENDED THE A&E DEMAND METHODOLOGY?

A. Yes. I am aware that Ameren has advocated for the A&E methodology in numerous rate cases. In addition, I understand that Westar has used the A&E allocator in several recent rate cases in Kansas. Finally, Empire has historically used the A&E allocator.

Q. HOW DID YOU ALLOCATE FUEL COSTS?

A. I allocated fuel costs based on each class' relative proportion of energy use at the generator (see line 3, Schedule KM-1).

Q. HOW DID YOU ALLOCATE NON-FUEL O&M COSTS?

A. As mentioned earlier, non-fuel O&M costs were classified as demand-related and allocated to classes using the A&E demand allocator. I would note that Staff allocates such costs on the same basis as I have (i.e., using the same demand based allocator to allocate non-fuel O&M costs as the production plant related costs) in allocating costs between jurisdictions in calculating its revenue requirement.

Q. HOW DID YOU ALLOCATE PURCHASED POWER CAPACITY COSTS?

A. I allocated such costs based on the demand allocator since these are capacity related costs.

Q. PLEASE EXPLAIN HOW YOU DERIVED THE AVERAGE AND EXCESS DEMAND ALLOCATOR 4NCP (AED4NCP) ALLOCATOR.

A. **Schedule KM-1** shows the derivation of the AED4NCP allocator. The method I utilized is consistent with the NARUC manual. Line 2 shows the average of the four non-coincident peaks ("NCP") by class and line 3 shows the annual energy (kWh) by class. Line 6 shows the average demand calculated by dividing the annual energy line 3 by 8,760. The excess demand shown in line 7 is calculated by subtracting the average demand in line 6 from the average of the 4NCP in line 2. The class average demand as a proportion to the system average demand was weighted by the load factor in line 8. The class excess as a proportion to the system excess was weighted by 1 minus the load factor in line 9. Line 10 shows the summation of these two weighted portions.

Q. WHAT DO YOUR CCOSS RESULTS INDICATE?

A. **Schedule KM-2** shows the detailed results. Table 3 shows a comparison of the results derived from my study as well as Staff's CCOSS. Specifically this table shows, at present rates, the return on rate base, the relative rates of return and amount of increases that would be required to move each customer class to the system average rate of return at current revenue levels.(i.e., revenue neutral changes) and before the rate increase. A positive revenue neutral change means the current rates for the class are resulting in revenues which are below costs to serve. Similarly, a negative revenue neutral change means the current rates for the class are resulting in revenues which are above costs to serve.

Table 3: MECG v. STAFF CCOSS RESULTS AT CURRENT RATES

	MECG				STAFF			
	Rate of Return at Current Revenues	Relative Rate of Return at current revenues	% Revenue Neutral Change	$ Revenue Neutral Change	Rate of Return at Current Revenues	Relative Rate of Return at current revenues	% Revenue Neutral Change	$ Revenue Neutral Change
	A	B	C	D	E	F	G	H
Residential	3.92%	0.66	7.45%	$15,748,235	3.94%	0.67	6.69%	$14,172,533
CB	7.83%	1.32	-5.45%	-$2,376,495	7.52%	1.27	-4.63%	-$2,019,954
SH	4.91%	0.83	3.44%	$363,329	5.19%	0.88	2.65%	$279,768
TEB	5.90%	0.99	0.19%	$71,327	6.06%	1.02	-0.12%	-$44,845
GP	10.20%	1.72	-10.81%	-$9,822,593	9.81%	1.66	-10.44%	-$9,475,416
LPS	7.34%	1.24	-4.18%	-$2,289,893	5.89%	0.99	-0.07%	-$40,051
SC-Praxair	7.68%	1.30	-4.93%	-$218,743	5.30%	0.89	1.41%	$62,332
PFM	11.16%	1.88	-14.30%	-$16,518	18.36%	3.10	-26.05%	-$30,065
Lighting	12.77%	2.15	-18.81%	-$1,458,642	22.64%	3.82	-37.72%	-$2,904,324
Total	5.93%	1.00			5.93%	1.00		

My results are similar to Staff's results in the following ways:

- Both CCOSS results indicate relative rates of return less than 1 and that a positive revenue neutral adjustment is needed for the Residential class and the Small Heating Class;

- Both COSS results indicate relative rates of return greater than 1 and show negative revenue neutral adjustments for the GP, PFM,CB and lighting classes.

My CCOSS results are different from Staff's results for the following classes:

- For the TEB class, my results indicate a slight positive revenue neutral adjustment whereas Staff's results show a slight negative revenue neutral adjustment;
- For the LP class and Praxair class, my results show relative rates of return greater than 1 and indicate negative revenue neutral adjustments of more than 4% while Staff's results show relative rates of return less than 1 and indicate a slight negative revenue neutral adjustment for the LP class and a positive revenue neutral adjustment for the Praxair class.

Q. DO THESE RESULTS DIFFER FROM YOUR FINDINGS IN THE LAST CASE?

A. In large part, no; the magnitude of course, varies due to revenue neutral adjustment actions taken in the last case. In the last case, I had found that the residential class needed a negative revenue neutral adjustment and all other classes needed a positive revenue neutral adjustment. In this case, the only exceptions are that the SH class also requires a negative revenue neutral adjustment and the TEB roughly breaks even. These changes could be due to the resulting impact associated with rate switching in between classes (for more detail, see Staff Revenue Requirement Report Page 77).

Q. WHAT IS THE COMPARISON OF THE CCOSS RESULTS WHEN STAFF'S RECOMMENDED REVENUE REQUIREMENT IS INCLUDED?

A. Table 4 shows the comparison of my CCOSS results with Staff's results using Staff's recommended revenue requirement.

Table 4: MECG v. STAFF CCOSS RESULTS AT STAFF'S RECOMMENDED REVENUE REQUIREMENT

	MECG CCOSS RESULTS		STAFF CCOSS RESULTS	
	REVENUE ABOVE (BELOW) COSS	% CHANGE NEEDED TO BRING CLASS REVENUE TO COST-OF-SERVICE	REVENUE ABOVE (BELOW) COSS	% CHANGE NEEDED TO BRING CLASS REVENUE TO COST-OF-SERVICE
Residential	-$25,330,091	11.9790%	-$23,766,240	11.2256%
CB	$400,436	-0.9183%	$41,350	-0.0947%
SH	-$841,887	7.9718%	-$758,151	7.1815%
TEB	-$1,792,295	4.7192%	-$1,675,059	4.4133%
GP	$5,703,773	-6.2752%	$5,364,254	-5.9126%
LPS	-$190,113	0.3474%	-$2,437,423	4.4582%
SC-Praxair	$17,869	-0.4031%	-$262,713	5.9410%
PFM	$11,282	-9.7646%	$24,835	-21.5164%
Lighting	$1,107,286	-14.2806%	$2,555,437	-33.1906%
Staff Recommended Revenue Deficiency	-$20,913,732	4.5314%	-$20,913,732	4.5314%

IV REVENUE ALLOCATION

Q. WHAT WERE STAFF'S RECOMMENDATIONS WITH RESPECT TO THE REVENUE ALLOCATION?

A. Staff had the following primary recommendations:

- A positive revenue neutral adjustment of $3.855 million to the Residential Class and a negative revenue neutral adjustment of the same amount to the GP Class;
- No rate increase for the PFM and Lighting classes and all other classes receive an equal percent increase after adjusting revenue deficiency for MEEIA related impacts which are handled as a separate step in the revenue allocation process.

Q. DO YOU SUPPORT THESE RECOMMENDATIONS?

A. Not entirely; while I certainly support the concept of revenue neutral adjustments, I believe that other classes in addition to the residential and GP class should get such adjustments in order to bring each class closer to costs to serve.

Q. PLEASE PROVIDE YOUR RECOMMENDED APPROACH FOR REVENUE NEUTRAL ADJUSTMENTS.

A. My recommendations for revenue neutral adjustments are as follows:

1. A positive revenue neutral adjustment of $4,000,000 (or approximately 25% of total revenue neutral change) for the residential which equates to 1.9% of Staff's calculation of tariffed revenues ($208.7 million); and
2. A negative revenue neutral adjustment of $600,000 for the CB class, $575,000 for the LP class and $2,825,000 for the GP class. From a revenue neutral adjustment standpoint, this is approximately a: (a) 25% positive revenue neutral adjustment for the Residential Class; (b) 25% negative neutral adjustment for the LP and CB class; and (c) 29% negative revenue neutral adjustment for the GP class. Expressed as percentages, this is a 1.9% revenue neutral increase to the Residential class and 1.4%, 3.2% and 1.1% reduction to the CB, GP and LP classes.[14]

   Table 5 shows the comparison of Staff's and my recommended revenue neutral adjustments.

[14] Similar to Staff, I used Staff's billing determinant related revenues to make this calculation (See Staff's Working Papers "Copy of Empire Rate Design.xlsx, tab interclass shifts

Table 5: COMPARISON OF MECG v. STAFF RECOMMENDED REVENUE NEUTRAL ADJUSTMENTS BY CLASS

	MECG			STAFF	
	% Revenue Neutral Change	$ Revenue Neutral Change	MECG Revenue Neutral Adjustment Recommendation	$ Revenue Neutral Change	STAFF Revenue Neutral Adjustment Recommendation
Residential	7.45%	$15,748,235	$4,000,000	$14,172,533	$3,855,000
CB	-5.45%	-$2,376,495	-$600,000	-$2,019,954	
SH	3.44%	$363,329		$279,768	
TEB	0.19%	$71,327		-$44,845	
GP	-10.81%	-$9,822,593	$2,825,000	-$9,475,415	-$3,855,000
LPS	-4.18%	-$2,289,893	-$575,000	-$40,051	
SC-Praxair	-4.93%	-$218,743		$62,332	
PFM	-14.30%	-$16,518		-$30,065	
Lighting	-18.81%	-$1,458,642		-$2,904,324	

Q. FOR WHICH CLASSES DO YOU RECOMMEND NO RATE INCREASE?

A. Similar to Staff, I recommend that PFM and Lighting classes get no rate increase. My cost of service results indicate that these classes are significantly above cost (See Tables 3 and 4). Further for SC-P, I also recommend no rate increase at Staff's recommended revenue requirement.

Q. PLEASE EXPLAIN YOUR REASONING AS TO WHY PRAXAIR SHOULD NOT GET A RATE INCREASE?

A. At Staff's recommend revenue requirement, my cost of service shows that Praxair's revenue is already above Empire's cost to serve the customer. This result occurs even after I have ignored the fact that Praxair is an interruptible customer and has been allocated full generation costs without regard to the interruptible nature of its load. As discussed in direct testimony and as noted by the Company, Empire does not make capacity decisions for Praxair because of the non-firm nature of its load and as such, capacity related costs should not be allocated to Praxair. [15]

Q. HOW SHOULD THE FINAL RATE INCREASE BE ALLOCATED TO CLASSES?

A. After making the revenue neutral adjustments, the final rate increase should be allocated to all classes (except PFM, Lighting and Praxair) on an equal percentage basis in proportion to their revenues after adjusting revenue deficiency for MEEIA related impacts.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[15] See my direct testimony pages 16-17.

Schedule KM-1

AED4NCP ALLOCATOR

Line No:	AED4NCP	Total	RG	CB	SH	TEB	GP	LP	Praxair	PFM	Lighting
1	System Peak	1,015,174	577,140	62,231	31,663	108,574	142,266	85,653	7,298	70	279
2	Average of 4 NCP	1,002,391	510,807	86,289	23,540	88,614	167,780	105,718	8,371	262	11,009
3	Sales	4,364,751,802	1,760,189,460	334,598,439	95,788,915	394,171,193	963,953,919	709,929,882	71,008,904	688,845	34,422,243
4	Load Factor	49.1%									
5	1 minus Load Factor	50.9%									
6	Average Demand	498,259	200,935	38,196	10,935	44,997	110,040	81,042	8,106	79	3,929
7	Excess Demand	504,131	309,872	48,093	12,606	43,617	57,740	24,676	264	184	7,080
8	Average Demand (%) weighted by load factor		19.8%	3.8%	1.1%	4.4%	10.8%	8.0%	0.8%	0.0%	0.4%
9	Excess Demand (%) weighted by 1 - load factor		31.3%	4.9%	1.3%	4.4%	5.8%	2.5%	0.0%	0.0%	0.7%
10		100.00%	51.091%	8.620%	2.350%	8.838%	16.671%	10.475%	0.825%	0.026%	1.102%

Schedule KM-2

MECG CCOSS SUMMARY RESULTS

Description	MO Adjusted Jurisdictional	Residential	CB	SH	TEB	GP	LPS	SC-Praxair	PFM	Lighting
TOTAL RATE BASE	$1,345,231,119	$709,956,817	$116,341,379	$32,651,446	$113,101,179	$209,991,057	$132,741,390	$9,178,604	$307,093	$20,962,153
TOTAL RETURN ON RATE BASE	$100,677,097	$53,133,168	$8,706,989	$2,443,634	$8,464,492	$15,715,731	$9,934,366	$686,927	$22,983	$1,568,808
TOTAL OPERATING & MAINT. EXPENSE	$350,354,071	$173,741,162	$30,661,047	$8,352,154	$28,722,558	$60,353,609	$41,158,422	$3,466,927	$66,134	$3,832,068
TOTAL INCOME TAXES	-$2,450,417	-$852,478	-$280,077	-$49,172	-$204,929	-$659,073	-$299,532	-$21,658	-$1,054	-$82,443
TOTAL DEFERRED INCOME TAXES	$34,662,426	$12,004,604	$3,971,158	$694,430	$2,897,245	$9,356,891	$4,242,847	$306,560	$14,972	$1,173,717
ADDITIONAL CURRENT TAX REQUIRED	$6,847,347	$2,382,129	$782,635	$137,405	$572,644	$1,841,688	$837,001	$60,521	$2,946	$230,376
TOTAL EXPENSES	$389,413,427	$187,275,417	$35,134,763	$9,134,817	$31,987,518	$70,893,115	$45,938,738	$3,812,350	$82,998	$5,153,718
CLASS COST OF SERVICE	$490,090,524	$240,408,585	$43,841,752	$11,578,451	$40,452,010	$86,608,846	$55,873,104	$4,499,277	$105,981	$6,722,526
CURRENT RATE REVENUE	$461,526,205	$211,453,299	$43,607,839	$10,560,868	$37,978,466	$90,894,516	$54,729,016	$4,432,900	$115,544	$7,753,758
CURRENT OTHER REVENUE	$7,650,587	$3,625,195	$634,349	$175,696	$681,249	$1,418,103	$953,975	$84,246	$1,719	$76,054
TOTAL CURRENT REVENUE	$469,176,792	$215,078,494	$44,242,188	$10,736,564	$38,659,715	$92,312,619	$55,682,991	$4,517,146	$117,263	$7,829,812
CURRENT RATE OF RETURN (ROR)	5.9293%	3.9162%	7.8282%	4.9056%	5.8993%	10.2002%	7.3408%	7.6787%	11.1580%	12.7663%
REVENUE ABOVE (BELOW) COS	-$20,913,732	-$25,330,091	$400,436	-$841,887	-$1,792,295	$5,703,773	-$190,113	$17,869	$11,282	$1,107,286
% CHANGE NEEDED TO BRING CLASS REVENUE TO COST-OF-SERVICE	4.5314%	11.9790%	-0.9183%	7.9718%	4.7192%	-6.2752%	0.3474%	-0.4031%	-9.7646%	-14.2806%
STAFF REVENUE REQ (% IINCREASE)		4.531%	4.5314%	4.5314%	4.5314%	4.5314%	4.5314%	4.5314%	4.5314%	4.5314%
% REVENUE NEUTRAL CHANGE NEEDED - BEFORE RATE INCREASE		7.4476%	-5.4497%	3.4403%	0.1878%	-10.8066%	-4.1841%	-4.9345%	-14.2960%	-18.8121%
$ AMOUNT REVENUE NEUTRAL CHANGE NEEDED - BEFORE RATE INCREASE		$15,748,235	-$2,376,495	$363,329	$71,327	-$9,822,593	-$2,289,893	-$218,743	-$16,518	-$1,458,642