Exhibit No.:	
Issue:	Class Cost of Study, Rate Design, Fuel Adjustment Clause
Witness:	Kavita Maini
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2014-0351
Date Testimony Prepared:	February 11, 2015

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

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

February 11, 2015

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

**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-2014-0351

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-2014-0351.

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
____
Kavita Maini

Subscribed and sworn to before me this 10th day of February, 2015.

JACOB HOTZ NOTARY PUBLIC STATE OF WISCONSIN

____
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-2014-0351** Tariff No. YE-2015-0074

TABLE OF CONTENTS

SCHEDULES

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

Direct 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. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am an economist with over 23 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with a Master's in Business and a Masters in Applied Economics. From 1991 to 1997, I worked for Wisconsin Power & Light Company ("WP&L") as a Market Research Analyst and Senior Market Research Analyst. In this capacity, I conducted process and impact evaluations for WP&L's Demand Side Management ("DSM") programs. I also conducted forward price curve and asset valuation analysis. From 1997 to 1998, I worked as Senior Analyst at Regional Economic Research, Inc. in San Diego, California. My responsibilities included DSM evaluations and forecasting using neural network software. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy Integrated Services' Energy Consulting Division. In this role, I was responsible for providing energy consulting services to commercial and industrial customers in the area of electric and natural gas procurement, contract negotiations, forward price curve analysis, rate design and on site generation feasibility analysis. I was also involved in strategic planning and due diligence on acquisitions.

Since 2002, I have been an independent consultant. In this role, I have provided consulting services in the areas of class cost of service studies, rate design, resource planning and revenue requirement related issues, Midcontinent Independent System Operator ("MISO") related matters and various policy matters. I also represent industrial trade associations at MISO's various task forces and committees and am the End Use Sector representative at MISO's Planning Advisory Committee.

Q. HAVE YOU PARTICIPATED IN OTHER UTILITY RELATED PROCEEDINGS?

A. Yes, I have testified before a number of state regulatory commissions. I have also submitted technical comments on a variety of issues related to energy policy and cost recovery, allocations and rate design in transmission and renewable rider proceedings before regulatory commissions. I have also provided technical comments in Federal

Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO related activities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying as an expert witness on behalf of the Midwest Energy Consumers Group ("MECG"). The MECG is an ad-hoc group of eight large commercial and industrial customers taking service from Empire on its Large Power and Special Transmission rate schedules. These customers are all listed among Empire's 20 largest customers and collectively use almost 450,000,000 kWh on an annual basis.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to discuss and provide recommendations regarding: (a) the Company's proposed changes to its Fuel Adjustment Clause ("FAC"), (b) MECG's class cost of service study findings, (c) an appropriate approach for allocating any rate increase among the customer classes and (d) rate design for the Large Power and Special Transmission rate schedules. The rest of my testimony is organized as follows:

Section II: Summary

Section III: Fuel Adjustment Clause

Section IV: Importance of competitive industrial rates and accurate pricing signals

Section V: Class Cost of Study

Section VI: Revenue Requirement Allocation

Section VII: Large Power and Special Transmission Rate Design

II. SUMMARY

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A The following is a summary of my testimony and recommendations:

SECTION III: Fuel Adjustment Clause ("FAC")

a) I share Office of Public Counsel ("OPC") witness Mantle's concern about Empire's proposal to continue the FAC. Further, should the FAC mechanism be continued, the Company has not provided an adequate assessment of benefits related to the Southwest Power Pool Integrated Marketplace ("SPP IM") which is the primary rationale for proposing to include RTO related fixed transmission costs;

b) In addition, recovering fixed transmission and natural gas transportation costs through the variable energy charge will disproportionately recover costs from high load factor customers and contradicts the Company's goal of recovering fixed costs through non volumetric charges and sending proper pricing signals;

c) Consequently, I recommend that the Company's proposal to include fixed transmission costs not be approved particularly when another rate case is imminent;

SECTION IV: Importance of Competitive Industrial Rates and Accurate Pricing Signals

a) Empire's industrial rates are not competitive. While Empire's residential rates are 3.5% below the national average, the Company's average industrial rate is 16% above the national average;

b) It is important for retail rates to reflect accurate pricing signals because they drive consumer behavior, which in turn results in more efficient use of the system thereby minimizing system costs. Provided that rates reflect cost of service, there is equitable recovery of costs from classes and customers have the proper pricing signals and incentive to respond to;

SECTION V: Class Cost of Service Study ("CCOSS")

a) A CCOSS study is the linchpin in establishing fair and reasonable rates because it (a) is used in the determination of the revenue requirement for the Company, (b) guides how the revenue requirement should be allocated to classes and (c) informs rate design. Thus, it is important that the CCOSS approach reflect cost causation;

b) Empire's load profile characteristics indicate that it is a summer and winter peaking utility; these months drives generation infrastructure decisions and should be used to derive the allocators for production costs;

c) Either the coincident peak method or the A&E method are reasonable allocation methods for fixed production plant related costs;

d) The A&E approach considers the load profile of customer groups by incorporating the maximum demands, load factor and average energy use and is reasonable method to use in this case. I recommend the AED6NCP production allocator;

SECTION VI: Revenue Requirement Allocation

a) In order to have equity amongst classes, I recommend that adjustments first be made on a revenue neutral basis such that the relative rates of return of each class are 1.00. Using this approach, I recommend a decrease of 7.7% to the Special Transmission Service Class ("Schedule SC-P") and a 1.3% decrease to the Large Power Class. After making these recommended revenue neutral adjustments at present rates, any overall change in revenue requirements can be applied across the board to the classes on an equal percentage basis.

b) In allocating the overall change in revenue requirements across the board to the classes on an equal percentage basis, it should be ensured that pre-MEEIA energy efficiency costs are excluded. Consistent with the statute, the pre-MEEIA costs should be assigned to the non-opt out customers only and should be separate from the overall revenue requirement increase.

SECTION VI: Large Power / Special Transmission Rate Design

a) In developing recommendations for rate design, I focused on developing better pricing signals based on the cost drivers in this case;

b) Regarding the LP rate schedule: I recommend the following:
   - Remove all fixed costs from the second energy block by adjusting the second energy block charge to coincide with the base cost of fuel. Any remaining adjustments to account for the fixed costs removed from this energy block should be made to the billing demand charge;

– Include a provision in the LP tariff indicating that to the extent a peak is set after an outage, it will not be used in conjunction with the demand ratchet for purposes of calculating future months' facilities charges;

c) Regarding the Schedule SC-P, my recommendations are to:
   – Increase the billing demand charge;
   – Increase the interruptible credit to recognize the value provided by such interruptible customers;

d) Interruptible load provides system benefits by reducing reserve margin requirements;

e) Interruptible customers opt for non-firm inferior service instead of firm service and agree to curtailments in order to manage their power costs. It is a business decision that takes into account the trade-off between shutting down certain processes / forgoing business related revenue against the compensation received for providing the interruptible service. Therefore, if the compensation is not adequate, it creates a barrier to participating and providing such service;

f) The interruptible load under Schedule SC-P has greater value because its notification time prior to initiating a curtailment is significantly less and the load can be curtailed for a larger number of hours compared to the Interruptible Rider;

g) Current credits for interruptible load are undervalued; with more equitable compensation for providing interruptible service, I believe that participation will increase. Should that happen, it is a win-win for the system and the customers providing this service – the utility will have less reserve margin requirements thereby minimizing system costs and the customers will have an option to manage their power costs. Thus, I recommend that the interruptible credit for the three and five year term in the Interruptible Rider be doubled and the current credit for the Schedule SC-P be increased by $1 per KW-month.;

III. FUEL ADJUSTMENT CLAUSE ("FAC")

Q WHAT IS THE COMPANY PROPOSING REGARDING THE FAC?

A The Company proposes to continue the FAC with significant modifications such as the inclusion of net Regional Transmission Organization ("RTO") transmission costs and natural gas transportation and storage costs. Empire witness Tarter describes these changes in his direct testimony. Empire witnesses Aaron Doll and Scott Keith also testify in support of the inclusion of Southwest Power Pool ("SPP") Integrated

Marketplace ("IM") related charges and transmission-related revenue and expense into Empire's FAC.

Q HAVE YOU REVIEWED OPC WITNESS LENA MANTLE'S DIRECT TESTIMONY REGARDING THE COMPANY'S PROPOSAL TO CONTINUE THE FAC WITH MODIFICATIONS?

A Yes, I have. I generally support witness Lena Mantle's reasoning and subsequent recommendations regarding this matter. Witness Mantle's primary recommendation is to discontinue the FAC for Empire and collect any prudently incurred fuel costs in base rates. I support this recommendation. The FAC was initially implemented to address volatility in fuel prices. Empire's own testimony indicates an expectation for fuel prices to decline (see Tarter Direct). As such, the need for an extraordinary device like an FAC is no longer applicable.

Alternatively, she recommends that should the Commission approve the FAC, only certain cost and revenues be allowed to pass through the FAC along with other requirements. With respect to the costs and revenues that should be allowed, her recommendation is to only include variable fuel commodity costs, variable fuel transportation costs, purchased power, the transmission costs of purchased power, and off-system sales - in other words, limiting the modifications to costs that are primarily variable in nature and/or consist of transporting purchased power. I agree with witness Mantle in this regard.

Q ASIDE FROM ISSUES IDENTIFIED BY WITNESS MANTLE, WHAT ARE YOUR SPECIFIC CONCERNS ABOUT EMPIRE'S INCLUSION OF FIXED COST RECOVERY THROUGH THE FAC?

A Should the Commission determine that it is reasonable for Empire to continue utilizing the FAC, my concerns of including fixed costs in addition to those cited by witness Mantle are as follows:

First, Empire has not provided an adequate assessment of benefits associated with SPP IM, one of the primary arguments that the Company has made in support of including SPP related transmission costs in the FAC. The Company needs to provide updated analysis prior to any inclusion of such costs;

Second, while Empire is making efforts to align recovery of fixed costs through fixed charges (see testimony of Overcast), the proposed changes to recover fixed costs associated with natural gas transportation and transmission through the FAC (collected on a per kWh basis) contradicts the Company's rate design objectives.

1. Determination of SPP IM Benefits

Q PLEASE EXPLAIN EMPIRE'S POSITION FURTHER REGARDING THE INCLUSION OF SPP/RTO TRANSMISSION COSTS IN THE FAC DUE TO SPP IM BENEFITS.

A Empire argues that since its participation in SPP's new Integrated Marketplace results in benefits that flow through the FAC, it should recover the costs that make these benefits possible in the same manner (See Witness Doll Direct at pages 4-5).

Specifically, Witness Tartar incorporates a 3% adjustment ($4.57 million) for benefits related to the SPP IM in Empire's quantification of net fuel costs to flow through the FAC. (see Schedule TWT-2).

Q WHAT DOES WITNESS TARTAR STATE IN MAKING THE 3% ADJUSTMENT FOR BENEFITS RELATED TO THE SPP IM?

A Witness Tartar indicates that he made the 3% benefit adjustment exogenous to the generation model since the SPP IM implementation is relatively recent and for transparency reasons. Witness Tartar specifically states the following:

> "…Empire has made an adjustment for anticipated SPP IM savings outside of the supply model used in this case. This SPP IM adjustment reduces the model generated energy cost. It was determined that this "post processing" approach would be best for this rate filing since the SPP IM has been in place for just a few months. While Empire has analyzed the market approach with models, it will take some time for the SPP IM to mature, to gain history and for modelers to gain confidence in the market based modelling approach. Additionally, Empire believes that for the purpose of developing an overall normalized energy cost for establishing a new FAC base in this case, it was important to model the system consistent with previous general rate case filings and make the SPP IM adjustment exogenous to the generation model for transparency purposes."

See Tartar Direct at page 20

Q WHAT IS THE BASIS OF THE 3% ADJUSTMENT?

A The basis of the 3% adjustment is reliance on a study conducted by Ventyx in 2009 and preliminary internal analysis. In response to MECG 4.3, Empire stated the following:

> "The Southwest Power Pool Integrated Marketplace (SPP IM) was designed to bring cost savings to the SPP footprint. The SPP IM is expected to lower total footprint production costs by incorporating unit commitment of resources on a regional basis instead of Market Participant by Market Participant. In addition, the SPP Integrated Marketplace will provide the costing mechanism to allow the consolidated balancing authority (CBA) to procure and deploy Regulation and Contingency Reserves on a system-wide basis.
>
> SPP investigated the financial benefits in studies by the Cost Benefit Task Force (CBTF) and/or consulting firms. The SPP IM went live on March 1, 2014, so Empire had limited actual market data to consider. There are no guaranteed percent savings values from the SPP IM, and any such values are estimates at this time. But since the SPP IM is in place, Empire wanted to recognize some expected market savings level while rebasing the FAC, since that is what the SPP IM was designed to accomplish.
>
> In this case, Empire selected 3% for the SPP IM savings based on SPP cost benefit studies and initial internal modeling. Actual estimated market savings to date have also been monitored. An SPP cost benefit study developed by Ventyx and dated April 7, 2009 is attached to this response.
>
> SPP cost benefit studies looked at various scenarios and had different savings estimates for different members. Empire has approximately a 2.5% load share in SPP. Based on the many projected savings discussed in the report, it was interpreted that Empire could potentially see a production cost savings close to the 3% level selected for this case. Empire's initial attempts to model the SPP market (conducted before the market was even in place) found an annual savings range of 1.8% to 4.4% or about an average of 2.5% over a four year period. Estimated savings to date (through about the first 8 months of the market) show about a 3.9% savings. But this value is model calculated and is not based on normalized conditions."

Q BASED ON EMPIRE'S RESPONSE, IS THE 3% A REASONABLE ESTIMATE OF THE SAVINGS ASSOCIATED WITH SPP IM?

A No, the 3% estimate seems to be based on a Ventyx study conducted in 2009 even though the SPP IM was not initiated until 2014. As such, it is difficult to have confidence in a study conducted several years ago. Further, the Company's analysis as articulated in MECG 4.3 indicates the tentative nature of the estimate used. While I appreciate the Company making efforts to account for benefits associated with SPP IM, an updated analysis is necessary.

Q. BASED ON THESE FINDINGS, WHAT ARE YOUR CONCLUSIONS?

A. Since SPP IM is nascent, as it was initiated on March 1, 2014, it makes sense to complete at least one full year and calculate actual benefits compared to before the SPP IM started. Empire should provide this analysis in the next case. Empire needs to demonstrate verifiable benefits instead of either (a) making assumptions from past studies that were conducted several years ago and prior to the initiation of the SPP IM or (b) using results from tentative and preliminary analysis.

Q WHAT ARE YOUR RECOMMENDATIONS?

A Should the Commission determine that it is reasonable to continue the FAC, I recommend that transmission costs not be included in the FAC at this time. The costs and benefits associated with the Company's participation in the SPP IM are still very tenuous. The Company needs to conduct the study providing verifiable benefits prior to contemplating recovery of fixed transmission costs in the FAC.

2. <u>Recovery of fixed costs through variable charges</u>

Q YOU HAD INDICATED EARLIER THAT YOU WERE CONCERNED ABOUT RECOVERING FIXED COSTS THROUGH A VOLUMETRIC CHARGE. PLEASE EXPLAIN.

A The Company's witness Edwin Overcast has indicated concerns that Empire's rates rely too heavily on the volumetric recovery of fixed costs. He indicates that volumetric recovery of fixed costs does not assign costs to cost causers and sends misleading pricing signals. I agree and share his concerns. Despite this stated concern, the Company's proposal to include fixed costs such as fixed natural gas transportation costs and transmission costs in the FAC and recover them through a volumetric charge: a) will further exacerbate the issue of assigning costs to cost causers, b) will send flawed pricing signals and c) will result in economic inefficiency. Given this inconsistency and unintended consequences, it dictates that these fixed costs be recovered through base rates.

Q. DO YOU HAVE ANY OTHER THOUGHTS THAT THE COMMISSION SHOULD CONSIDER WHEN DECIDING WHETHER TO EXTEND THE FAC TO INCLUDE TRANSMISSION COSTS?

A. Yes. Empire has indicated that, immediately following the completion of this case, it will be filing another rate case in order to recover another capital project. This means that any increases or decreases in these fixed costs will be incurred during the test year of the next case and be considered for recovery in this next case. Given the immediacy of the next case, the need for extending the FAC is not as important.

IV. IMPORTANCE OF COMPETITIVE INDUSTRIAL RATES AND ACCURATE PRICING SIGNALS

Q HOW ARE MECG MEMBERS IMPACTED BY THIS PROCEEDING?

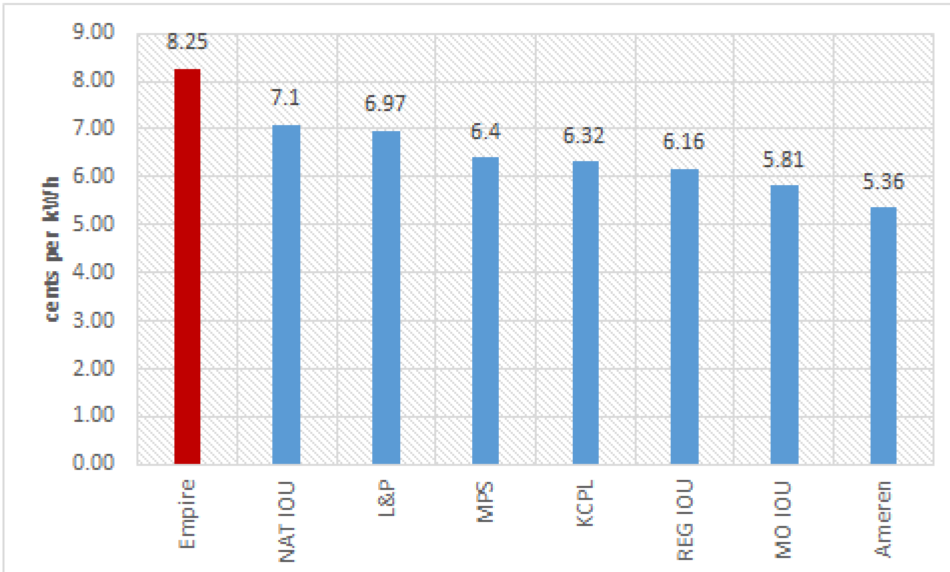
A Many of MECG member companies operate energy intensive facilities and are therefore sensitive to energy cost increases, which affect their overall cost of doing business. Thus, energy affordability affects the competitiveness, output and potential employment levels for these companies. High energy costs directly impact the bottom line of industrial customers because in many cases, these costs cannot be passed to downstream customers or markets due to highly competitive business conditions.

In the current case, Empire is proposing an above average rate increase for the Large Power class. Such an increase has the potential to adversely impact MECG group members particularly when the Company's current industrial rates are already not competitive. An above average proposed increase for the LP class is attributable, in large part, to the misapplication of the Class Cost of Service Study ("CCOSS") method used to guide revenue requirement allocation to classes. I will discuss the errors in Empire's witness Dr. Edwin Overcast's CCOSS in my rebuttal testimony.

Q WHAT IS YOUR BASIS FOR STATING THAT EMPIRE'S CURRENT RATES ARE NOT COMPETITIVE?

A I compared Empire's average industrial rate with the average industrial rates of other investor owned utilities in Missouri as well as regional and national averages. Figure 1 shows the comparison for 2014. As can be observed from this chart, Empire's rates are not only the highest amongst investor owned utilities in Missouri but also the highest compared to the regional and national average. Specifically, Empire's industrial rate is 33% and 16% higher than the regional and national averages respectively. While Empire's industrial rate is now 16% above the national average, just 5 years ago it was below the national average.

Figure 1: 2014 Average Industrial Rate Comparisons[1]



Q WHY ARE COMPETITIVE INDUSTRIAL RATES IMPORTANT?

A Competitive industrial rates are an important factor in helping to retain and expand industry within the utility's service area. Business retention and expansion result in positive impacts on local economy and employment. Further, if businesses relocate or expand in Empire's service area, it has the potential of lowering costs for customers as the fixed costs are spread over larger amount of billing determinants. The converse is also true – if businesses shift operations from Empire's area, the remaining customers bear the burden of the same fixed costs but over a smaller amount of billing

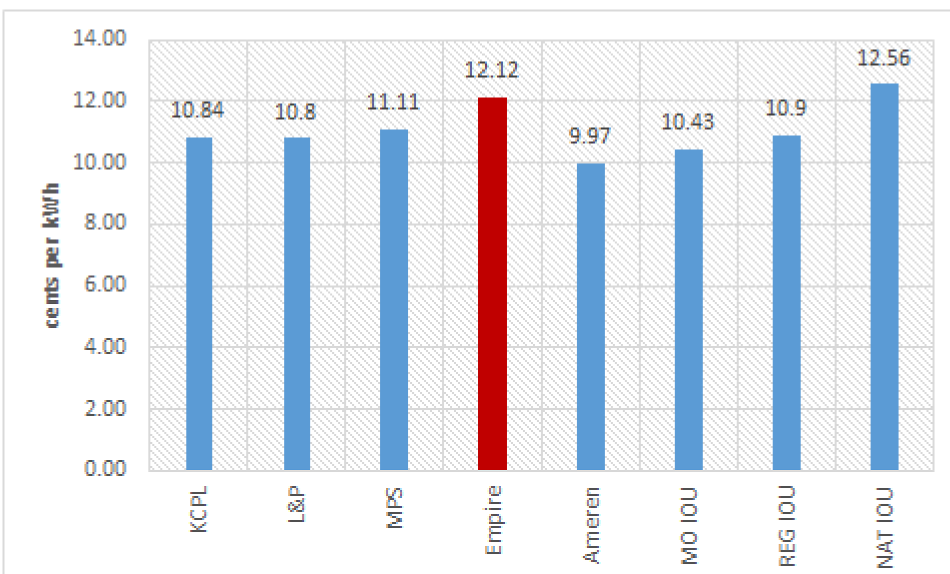
[1] Source: Typical Bills and Average Rates Report Summer 2014, published by Edison Electric Institute.

determinants thereby increasing rates for all customers. Thus, the Commission should be cognizant of how its decisions affect industrial rates.

Q HOW DO EMPIRE'S RESIDENTIAL RATES COMPARE WITH OTHER INVESTOR OWNED UTILITIES IN MISSOURI AND ON A REGIONAL AND NATIONAL LEVEL?

A Figure 2 shows the comparison. While Empire's residential rates are high as well, it is worth noting that they are 3.5% below the national average. As discussed earlier, the Company's average industrial rate is 16% above the national average. Similarly, while Empire's residential rate is 11% above the regional average, the Company's average industrial rate is 34% above the regional average.

Figure 2: 2014 Average Residential Rate Comparisons[2]



[2] Source: *Id.*

Q WHAT COULD BE CAUSING THE INDUSTRIAL RATES TO BE LESS COMPETITIVE THAN THE RESIDENTIAL RATES?

A A critical factor could be not assigning costs to those classes that cause them; leading to a misalignment of rates with the embedded costs to serve. Indeed, as discussed later in my testimony, the relative rate of return at present rates indicate that the Company is recovering significantly less than it costs to serve from the residential class. All other classes (except for lighting) have a relative rate of return greater than 1. Retail rates are pricing signals that drive customer behavior. As such, they should be aligned as reasonably as possible to the cost to serve. Any CCOSS approach should be aimed at allocating costs to those that cause them.

Q WHY IS IT IMPORTANT FOR RETAIL RATES TO REFLECT ACCURATE PRICING SIGNALS?

A It is important for retail rates to reflect accurate pricing signals because they drive consumer behavior, which in turn results in more efficient use of the system thereby minimizing system costs. Provided that rates reflect costs to serve, there is equitable recovery of costs from classes and customers have the proper pricing signals and incentive to respond to. For example if <u>fixed</u> transmission and generation costs are recovered through <u>variable</u> (energy) charges, it distorts the pricing signal to the customers. Specifically, by including such costs in the energy charge, the demand charge is kept artificially low, thus implying that generation capacity and transmission is cheaper than is actually the case. Similarly, the energy charge is now artificially high, thus implying that energy costs are more expensive than is actually true. Such a signal will then result in customers choosing to use less energy but contributing more to peak conditions. Further, over pricing the energy charge disproportionately recovers costs from customers and classes that have relatively flatter load profiles and use the system more efficiently. In this regard, my recommendations discussed later in this testimony are aimed at improving pricing signals through rate design, which ultimately is also driven by proper cost allocation to classes in the CCOSS.

V. CLASS COST OF SERVICE STUDY ("CCOSS")

Q WHY IS A CCOSS IMPORTANT?

A A CCOSS study is the linchpin in establishing fair and reasonable rates because it (a) is used in the determination of the revenue requirement for the Company, (b) guides how the revenue requirement should be allocated to classes and (c) informs rate design. Thus, it is important that any CCOSS approach reflect cost causation.

Q **WHAT ARE THE CONSEQUENCES OF A CCOSS APPROACH NOT REFLECTING COST CAUSATION?**

A If a CCOSS approach does not reflect cost causation, costs are not allocated to those that cause them resulting in inequity amongst classes and unreasonable rates for classes that are paying more than it costs to serve them. Further, the rates developed from the CCOSS send flawed pricing signals.

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 WHAT IS THE FOCUS OF YOUR CCOSS ANALYSIS IN THIS TESTIMONY?

A In this testimony, my focus is primarily on the allocation of fixed production plant costs to classes in the Company's CCOSS although I also made one change to the classification of purchased power (demand). Everything else in the Company's CCOSS model was left unchanged.[3]

Q PRIOR TO DISCUSSING PRODUCTION COSTS ALLOCATION, PLEASE EXPLAIN THE CHANGE TO THE CLASSIFICATION OF PURCHASED POWER (DEMAND).

A In the Company's CCOSS, purchased power (demand) is classified as energy related. In the Company's workpapers entitled "Datasheetv4proprietary", there are two 555 account listings: purchased power (energy) at $42.748 million and purchased power (demand) at $8.284 million. Empire's CCOSS indicates that both these costs were improperly classified as energy related. Since the purchased power is for demand or capacity, it should be classified as demand related. I made this adjustment to my CCOSS.

Q WHAT METHOD DOES COMPANY WITNESS DR. EDWIN OVERCAST USE IN HIS CCOSS FOR FIXED PRODUCTION PLANT?

A He indicates that he uses the average and excess method for fixed production plant. However, my analysis indicates that he misapplied the method which resulted in a double counting of the energy component and disproportionately allocating costs to

[3] In response to MECG 6.2, the Company indicated that the cost of service information was based upon adjusted test year information ending December 31, 2013. The rate case was based upon a test year ending April 30, 2014 with adjustments for known and measurable items through December 31, 2014. Since the Company did not attempt to reconcile the differences between the Cost of Service test year and the test year used in the rate case, I used the same information to be able to make apples-to-apples comparisons with the utility's CCOSS results.

classes that have flatter profiles and more efficiently use the system. I will provide an assessment of his allocation of fixed production plant in my rebuttal testimony.

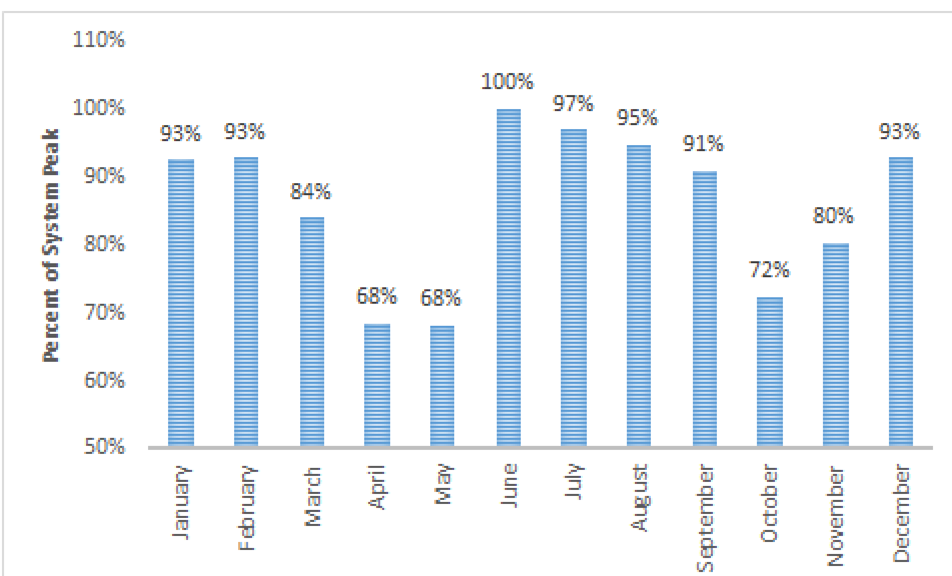
Q WHAT IS THE PRIMARY DRIVER IN DETERMINING COST CAUSATION WITH RESPECT TO COSTS CLASSIFIED AS FIXED PRODUCTION PLANT?

A The system load profile characteristics are the primary factor which drive production plant investment decisions. The contribution of each class' demand in these peak periods is therefore, what cause the costs.

Q DID YOU ANALYZE EMPIRE'S SYSTEM LOAD?

A Yes, I did. Figure 3 shows the system monthly peaks as a percent of overall system peak for the period used in the Company's CCOSS. This chart shows that the system peaked in June.

Figure 3: Monthly Peaks as a Percent of System Peaks



An examination of the system peaking months for past years has indicated that the system has peaked in the winter months as well (See **Schedule KM-1**). As indicated in this Schedule, in 2010, the system peak month was January and the highest summer peak was in August and 95% of the system peak. In 2011, the system peak was in the summer in August and in the winter, February was 96% of the system peak.

Q WHAT DO YOU ASCERTAIN FROM THE COMPANY'S PEAK DEMAND CHARACTERISTICS?

A I ascertain that the utility is both summer and winter peaking and that fixed production plant costs should be allocated to classes based on their contribution to system demands during these months. In 2013, the system peak was in the summer in June while July and August were 97% and 95% of the system peak. The winter seasonal peaks in December-February were similar and 93% of the system peak. Thus, June through August and December through February capture the predominant seasonal peak months respectively. The rest of the months do not drive Empire's decision to build more generation infrastructure. Therefore, they should not be considered in determining cost causation.

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 reasonable.

Q WHAT IS THE COINCIDENT PEAK DEMAND METHOD?

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.

Q WHAT IS THE AVERAGE & EXXCESS DEMAND METHOD?

The A&E Demand method consists of an average component and an excess component. The average component is the average demand and represents energy usage at a 100% load factor. The average demand 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 then calculated as the difference between the class' maximum non-coincident peak or peaks and the previously calculated 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.[4] The composite allocator is the sum of the weighted average and excess components.

The A&E approach considers the load profile of customer classes 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 Case No. ER-2010-0036:

> 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

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

> 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 methods are included in the NARUC manual and are compatible with least cost resource planning. In terms of developing the allocator, either 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 a reasonable approach.

Q WHICH ALLOCATION METHOD DO YOU RECOMMEND IN THIS CASE?

A I recommend the A&E demand method. As indicated, Empire is both a winter and summer peaking utility. Therefore, I recommend the A&E methodology which relies on the peaks experienced during three summer months (June through August) and three winter months (December through February) ("AED6NCP") in this case. I would also note that the 6CP coincident peak method, non-A&E methodology, delivered similar results.

With respect to the non-coincident peaks, the six months of June-August and December-February represent the summer and winter 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 six peaking months.

Q PLEASE EXPLAIN HOW YOU DERIVED THE AED6NCP ALLOCATOR.

A **Schedule KM-2** shows the derivation of the AED6NCP allocator. The method I utilized is consistent with the NARUC manual. Line 2 shows the average of the six 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 8760. The excess demand shown in line 7 is calculated by subtracting the average demand in line 6 from the 6NCP average peak 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 HOW DID YOU ACCOUNT FOR THE INTERRUPTIBLE LOAD IN THE SPECIAL TRANSMISSION SERVICE CLASS?

A The Special Transmission Service's interruptible load provides value to the system in that it helps reduce capacity needs. Empire's capacity margin requirement, as dictated by SPP, is firm system load plus a 12% capacity margin. Therefore, Empire's capacity margin requirement does not include interruptible load. In this case, I included all of the Special Transmission load as if it were firm thereby allocating all fixed production plant related costs to this class. This means that all fixed production plant costs were allocated to this class even though this class, because it is interruptible, does not contribute to system peak requirements. The rate of return, however, was calculated using revenues prior to subtracting the credit and outside the CCOSS model.

Q **WHAT DO THE RESULTS INDICATE?**

A **Schedule KM-3** shows the detailed results. For comparison purposes, Figure 4 compares, at present rates, the return on rate base and relative rates of return derived from my study and well as the Company's CCOSS. For the LP and Special Transmission (SC-P) classes in particular, the results are different in that my results indicate that at present rates, the rates of return are higher than the system average. In contrast, Empire's study indicates that both classes are below the system average. As indicated earlier, however, the Company's application of the A&E demand method is flawed. I will provide an assessment of the Company's flawed approach in my rebuttal testimony.

Figure 5: MECG v. Empire's CCOSS Return on Rate Base ("RORB") and Relative Rate of Return by Class at Present Rates

	MECG CCOSS RESULTS			EMPIRE CCOSS RESULTS	
	RORB	Relative Rates of Return		RORB	Relative Rates of Return
Residential	2.99%	0.45		4.18%	0.62
CB	7.15%	1.07		7.30%	1.09
SH	6.91%	1.03		6.39%	0.95
TEB	12.18%	1.82		11.36%	1.70
GP	17.80%	2.66		13.70%	2.04
LP	7.05%	1.05		4.76%	0.71
PFM	12.44%	1.86		13.70%	2.04
SC-P	9.08%	1.36		4.13%	0.62
SPL	2.07%	0.31		3.04%	0.45
PL	23.72%	3.54		24.40%	3.64
LS	-13.20%	-1.97		-1.87%	-0.28
Company	6.70%	1.00		6.70%	1.00

VI. REVENUE REQUIREMENT ALLOCATION

Q HOW SHOULD THE REVENUE REQUIREMENT BE ALLOCATED TO CLASSES?

A As I mentioned earlier, the CCOSS is critical to establishing fair and reasonable rates. It is used to determine revenue requirement for the Company and should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. In order to have equity amongst classes, I recommend that adjustments be made on a revenue neutral basis at present rates such that relative rates of return are at 1 for each class. This is shown in **Schedule KM-4**. Line 8 shows the change in revenue needed to achieve the relative rates of return of 1 for each class at present rates.

Using this approach, I recommend a decrease of 7.7% to the Special Transmission Service Class and a 1.3% decrease to the Large Power Class (See **Schedule, KM-4**, line 9). After making these recommended revenue neutral adjustments at present rates, any overall change in revenue requirements authorized by the Commission should be applied across the board to the classes on an equal percentage basis.

Q DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS?

A Yes; in allocating the overall change in revenue requirements across the board to the classes on an equal percentage basis, it should be ensured that pre-MEEIA costs are excluded. Section 393.1075 provides that certain customers can opt out of a utility's energy efficiency costs. Therefore, Empire's pre-MEEIA costs should be assigned to the non-opt out customers only and should be separate from the overall increase. In response to MECG 8.8, the Company provided an updated worksheet of customers that opted out and the associated kWh. The cost allocations should be updated with this latest information. **Schedule KM-5** shows the changes in the allocations.

VII LARGE POWER / SPECIAL TRANSMISSION RATE DESIGN

Q WHAT CRITERIA SHOULD BE CONSIDERED IN DEVELOPING RECOMMENDATIONS REGARDING RATE DESIGN FOR INDUSTRIAL CUSTOMERS?

A Rate design decisions should focus on developing better pricing signals for customers. Given this, I am recommending certain changes to the rate design for both the Interruptible / Special Transmission as well as the Large Power rate schedules.

Q WHAT ARE YOUR RECOMMENDATIONS FOR THE INTERRUPTIBLE RIDER / SPECIAL TRANSMISSION RATE SCHEDULE?

A I recommend higher interruptible credits for both (a) the Interruptible Rider ("IR") to encourage participation and (b) Schedule SC-P to more equitably compensate for the interruptible benefits provided by these class participants. These recommendations are discussed further below.

Q WHAT ARE YOUR RECOMMENDATIONS REGARDING THE LARGE POWER RATE?

A My recommendations are consistent with Overcast's view that fixed costs should be phased out of energy charges.

First, I recommend that all fixed costs be removed from the second block energy rate. This is done by adjusting this energy rate to coincide with the base cost of fuel. After all, energy costs are meant to recover variable charges and this movement will align the energy charge with the base cost of fuel and send the proper pricing signal. Witness Tartar indicates that the existing FAC base is $28.31 per MWh and a comparable value without proposed changes would be $27.47 per MWh – a reduction of 3% (See Tartar testimony). To recognize this change, I recommend that the second energy block be decreased to $27.47 per MWh to coincide with the base cost of fuel. The fixed costs removed from the second energy block should instead be recovered through the Billing Demand charge. This increase in the billing demand charge is consistent with the driver underlying Empire's case (the capital costs of the AQCS at the Ashbury Generation Power Plant) and sends an appropriate pricing signal.

Second, I recommend that, with respect to setting the demand for the facilities demand charge, if the Company has an outage, the customers should not be penalized for setting a peak after the outage is restored. Since the facilities demand charge is ratcheted, customers should not be forced to pay charges for a peak set after an outage particularly when they did not cause the outage. Thus, my recommendation is to include a provision in the LP tariff indicating that, to the extent a peak is set within 12 hours after an outage it will not be included for purposes of calculating the distribution facilities charges for future months.

Finally, similar to the Schedules SC-P and SC-T, it would also be preferable to time differentiate the billing demand charge in the Large Power rate schedule to send the proper signal regarding transmission and generation infrastructure costs. Time differentiation of the billing demand sends pricing signals that encourage industrial customers to shift operations to move any peaks to an off-peak period. In this way, future utility capacity additions can either be postponed or cancelled. MECG requests that the Commission order Empire to submit a Large Power rate schedule in its next case that recognizes a time differentiated billing demand charge for the Large Power class.

Q. PLEASE COMMENT ON THE COMPANY'S PROPOSED CHANGES TO SCHEDULE SC-P ASSUMING IT RECEIVES ITS PROPOSED REVENUE REQUIREMENT INCREASE.

A The Company proposes to increase the transmission facilities demand charge from \$0.48 per KW-month to \$4.5 per KW-month. I support witness Overcast's overall approach and movement towards recovering fixed costs from demand charges instead of the energy charge. However, instead of increasing the <u>facilities</u> demand charge, I recommend that this increase be recovered from the <u>billing</u> demand charge. There are several reasons for this recommendation:

1. The billing demand charge should recover increases in fixed transmission and generation infrastructure costs. In contrast, the facilities demand charge is designed to recover fixed distribution infrastructure costs.

2. The increase in the billing demand charge, instead of the facilities demand charge, is consistent with the utility's primary case driver, the AQCS at the Asbury Generation Power Plant. Therefore, applying the rate increase to the billing demand charge sends an appropriate pricing signal

3. In Empire case ER-2011-0004, witness Overcast concluded that there were no increases necessary in the facilities demand charge and that the facilities demand charge should be eliminated. Further, he recommended that any increases should be recovered from the demand charge. It is also my understanding that the Company currently recovers excess facility charges through Rider XC from this Schedule.

Q HAS THE COMPANY PROPOSED ANY CHANGES TO THE INTERRUPTIBLE CREDITS IN SCHEDULE SC-P OR THE INTERRUPTIBLE RIDER ("IR")?

A No; the Company has not proposed any changes to the interruptible credit.

Q. HOW DO INTERRUPTIBLE CUSTOMERS BENEFIT THE UTILITY SYSTEM?

A. Interruptible customers forgo firm service. Empire utilizes the interruptible load to net against its load forecast prior to determining the planning reserve margin requirement. According to SPP rules, utilities' system load obligations are based on firm load plus a 13.6% planning reserve or capacity margin. [5] So, for example, if Empire system firm

[5] SPP has a 12% capacity margin (i.e., supply-demand/supply) which translates to a 13.6% planning reserve margin (i.e., supply-demand/demand)

load was 1000 MW, it would need to have 1000 MW plus 136 MW capacity =1136MW to comply with the SPP requirement. Now if it were assumed that Empire had 100 MW of interruptible load, the utility would be required to carry only 1022 MW of reserves (900 MW + 122 MW), a reduction of 114MW in reserve margin requirements. Thus, interruptible customers benefit the system by postponing the need to build or buy generation for capacity and reliability purposes. This is the reason that interruptible customers get interruptible credits. To be clear, this is not a discount but rather a credit to compensate interruptible customers for forgoing firm service and being available for curtailment.

Q WHY DO CUSTOMERS FORGO FIRM SERVICE AND INSTEAD OPT FOR INTERRUPTIBLE SERVICE?

A Customers opt for an inferior service and agree to curtailments in order to manage their power costs. It is a business decision that takes into account the trade-off between shutting down certain processes and forgoing revenue against the compensation received for providing the interruptible service. Therefore, if the compensation is not adequate, it undermines the success of the interruptible schedule.

Q DOES EMPIRE HAVE MANY INTERRUPTIBLE CUSTOMERS TAKING SERVICE IN THE IR OR SCHEDULE SC-P?

A No. Based on the load and capability statement provided by the company, it is my understanding that the Company has just one interruptible customer. With more equitable compensation for providing interruptible service, I believe that participation will increase. Should that happen, it is a win-win for the system, the firm service customers and the customers providing this interruptible service – the utility will have less reserve margin requirements thereby minimizing system costs and the customers will have an option to manage their energy costs.

Q WHAT ARE THE CURRENT INTERRUPTIBLE CREDITS IN THE IR FOR A THREE YEAR AND FIVE YEAR TERM?

A The current interruptible credits are $1.27 per KW-month ($15.24 per KW/year) and $2.02 per KW-month ($24.24 per KW-year) for a three and five year term respectively in the IR. Customers are provided with a four hour notification prior to the start of a notification event. The number of Curtailments Events in a Curtailment Year are no more than ten (10) and the cumulative hours of curtailment are not to exceed 80 hours during the Curtailment Year.

Q WHAT ARE THE INTERRUPTIBLE CREDITS IN THE SCHEDULE SC-P?

A The credits are $4.01 per KW-month or $48.12 per KW-year. Regarding SC-P, the requirements are a significantly less notification time – 30 minutes, which is akin to notification for non-spinning reserves. The maximum number of curtailments are also higher at 100 hours.

Q HOW ARE INTERRUPTIBLE CREDITS CONVENTIONALLY CALCULATED?

A Provided that interruptible credit agreements are for three or more years, interruptible credits are conventionally guided by the avoided cost of a combustion turbine. MISO's FERC approved cost of new entry (which is basically the cost of a new peaking unit) is $90/KW-year.[6] These numbers need to be adjusted for losses and reserve margin to arrive at the avoided cost. Even without accounting for such adjustments, the interruptible credits in the IR or the Schedule SC-P are significantly less.

Q ARE THE COMPANY'S CURRENT CAPACITY COSTS LOW?

A No; as indicated in the tariffs for LP class and Schedule SC-P, current firm demand charges that recover capacity costs are: $13.70 Summer, $7.57 Non Summer for the LP class and $23.95 Summer and $16.27 Non Summer respectively.

Q WHAT IS YOUR RECOMMENDATION IN THIS CASE FOR THE IR CLASS?

A My recommendation is to make some advancements in making the interruptible credit more equitable and allow for greater participation. I recommend that the interruptible credit for the three and five year term in the IR be doubled. In other words, increase the credit for the three year term to $2.44 per kW month and for the five year term to $4.04 per KW–month for customers that are willing to curtail service.

[6] See docket ER14-2808-000; this number can also be verified by using the Energy Information Administration combustion turbine cost of $676/KW http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf). Using a fixed charge rate of 13%, yields $88/KW-year

Q WHAT IS YOUR RECOMMENDATION IN THIS CASE FOR THE SCHEDULE SC-P CLASS?

A Since the he notification time for the SC-P class is 30 minutes (compared to 4 hours for the IR) and akin to non-spinning reserve service, it has greater value. Thus, the compensation should be higher than that provided for in the IR. I recommend that the credit for this schedule be increased by $1 per KW-month to $5.01 per KW-month.

Q IS THE VALUE OF INTERRUPTIBLE LOAD LIKELY TO INCREASE IN THE FUTURE?

A Yes. As a result of EPA rules, there are significant concerns about premature coal retirements thereby having the potential to threaten reliability. For example, SPP's analysis indicates significant concerns about resource adequacy regarding EPA's 111(d) rule.[7] Having access to interruptible load will help mitigate this concern.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

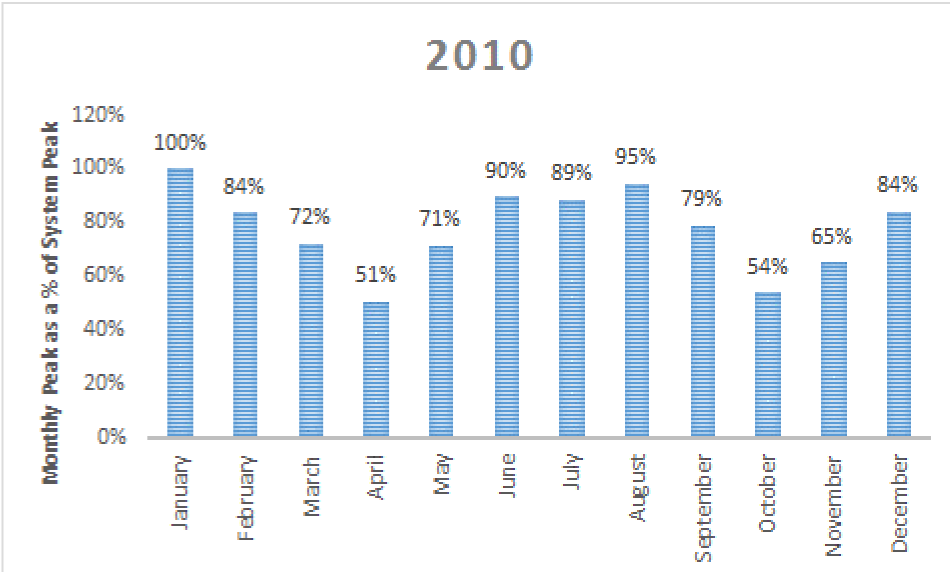
A Yes.

---

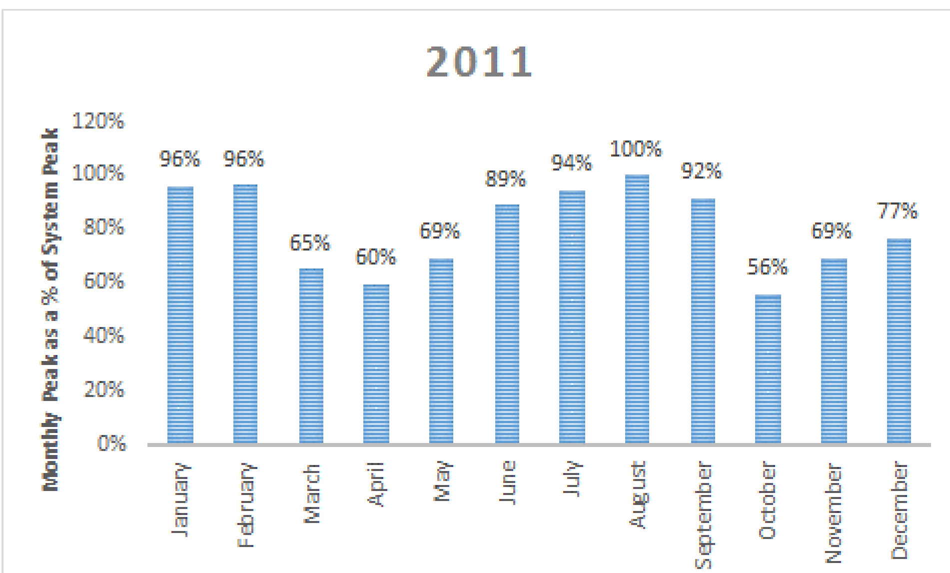
[7] See response to MECG Data Request 8.9

Schedule KM-1

Monthly Peaks as a Percent of System Peaks: 2010



Monthly Peaks as a Percent of System Peaks: 2011



Schedule KM-2

Development of the AED6NCP Allocator

Line No:	AED6NCP	Total	Res Gen	Comm	Comm SH	Gen Pow	Special Transmission Service	Tot.Elec. Bldg	Feed Mill	Large Pow	Misc Lts	Street Lts	Private Lts	Spec Lts
			0	1	2	3	4	5	6	7	8	9	10	11
1	MO System Peak	886,552	415,821	86,409	17,453	161,021	6,988	73,575	110	125,159	17	0	0	0
2	Average of 6 NCP	916,362	460,414	76,534	20,020	143,926	8,267	76,746	176	120,333	17	5,060	3,931	940
3	Sales	4,065,905,721	1,693,510,298	309,429,188	88,784,630	845,841,313	59,768,807	367,584,161	428,398	667,895,731	132,876	18,192,223	13,706,480	631,615
4	Load Factor	52.4%												
5	1 minus Load Factor	47.6%												
6	Average Demand	464,144	193,323	35,323	10,135	96,557	6,823	41,962	49	76,244	15	2,077	1,565	72
7	Excess Demand	452,218	267,091	41,211	9,885	47,369	1,444	34,784	127	44,089	1	2,983	2,366	868
8	Average Demand (%) weighted by load factor	52.4%	21.81%	3.98%	1.14%	10.89%	0.77%	4.73%	0.01%	8.60%	0.00%	0.23%	0.18%	0.01%
9	Excess Demand (%) weighted by 1 - load factor	47.6%	28.14%	4.34%	1.04%	4.99%	0.15%	3.66%	0.01%	4.65%	0.00%	0.31%	0.25%	0.09%
10		100.00%	49.95%	8.33%	2.18%	15.88%	0.92%	8.40%	0.02%	13.25%	0.00%	0.55%	0.43%	0.10%

Data Source: Company's Workpapers: Datasheet 2014 Proprietary

Schedule KM-3

Cost of Service Study Results Based on AED6NCP

		Missouri	Res Gen	Comm	Comm SH	Gen Pow	Prax	Tot.Elec. Bldg	Feed Mill	Large Pow	Misc Lts	Street Lts	Private Lts	Spec Lts
Line No:		Retail	RG	CB	SH	GP	SC-P	TEB	PFM	LP	MS	SPL	PL	LS
1	Sales Revenue	433,097,698	200,542,716	41,135,058	9,972,022	82,741,122	3,715,339	36,324,331	76,947	52,175,871	13,756	2,257,598	4,393,114	115,536
2	Total Revenues	455,183,283	211,693,398	42,736,436	10,408,311	86,515,457	3,949,944	38,066,136	79,113	55,197,520	14,313	2,318,718	4,451,184	118,466
3	Operating Expenses	259,007,487	126,709,966	22,520,044	5,776,912	43,946,789	2,612,364	20,411,279	34,812	34,386,981	14,363	1,275,086	1,176,678	142,210
4	Depreciation Expenses	62,274,122	34,736,953	6,383,569	1,473,529	7,937,404	324,718	4,141,387	10,776	6,221,443	1,178	458,138	511,723	73,305
5	Other Taxes	21,833,107	12,090,533	2,225,576	514,443	2,824,410	125,945	1,470,350	3,712	2,228,706	748	154,083	170,915	23,687
6	Income Taxes	31,457,654	17,359,533	3,198,973	743,008	4,083,992	181,233	2,140,159	5,327	3,231,376	600	226,624	252,010	34,820
7	Total Expenses	374,572,370	190,896,985	34,328,162	8,507,892	58,792,595	3,244,261	28,163,176	54,627	46,068,505	16,889	2,113,930	2,111,326	274,022
8	Operating Income	80,610,913	20,796,413	8,408,274	1,900,419	27,722,861	705,683	9,902,960	24,485	9,129,015	-2,576	204,788	2,339,858	-155,556
9	Gains/losses/interest on cust dep	-4,052,345	-2,198,441	-396,100	-93,337	-567,898	-30,753	-275,212	-577	-442,035	-160	-22,208	-22,296	-3,329
10	Net Income	76,558,568	18,597,972	8,012,174	1,807,082	27,154,963	674,931	9,627,748	23,909	8,686,980	-2,735	182,580	2,317,562	-158,885
11	Rate Base	1,142,391,460	621,876,224	112,119,105	26,157,144	152,514,471	7,434,710	79,024,061	192,116	123,238,911	23,506	8,835,886	9,771,484	1,203,840
12	Return on Rate Base	6.70%	2.99%	7.15%	6.91%	17.80%	9.08%	12.18%	12.44%	7.05%	-11.64%	2.07%	23.72%	-13.20%
13	Relative Rate of Return	1.00	0.45	1.07	1.03	2.66	1.35	1.82	1.86	1.05	-1.74	0.31	3.54	-1.97

Schedule KM-4

Cost of Service Study Results and Revenue Neutral Adjustments

		Missouri	Res Gen	Comm	Comm SH	Gen Pow	Prax	Tot.Elec. Bldg	Feed Mill	Large Pow	Misc Lts	Street Lts	Private Lts	Spec Lts
Line No:		Retail	RG	CB	SH	GP	SC-P	TEB	PFM	LP	MS	SPL	PL	LS
1	Rate Base	1,142,391,460	621,876,224	112,119,105	26,157,144	152,514,471	7,434,710	79,024,061	192,116	123,238,911	23,506	8,835,886	9,771,484	1,203,840
2	Return on Rate Base	6.70%	2.99%	7.15%	6.91%	17.80%	9.08%	12.18%	12.44%	7.05%	-11.64%	2.07%	23.72%	-13.20%
3	Relative Rate of Return	1.00	0.45	1.07	1.03	2.66	1.35	1.82	1.86	1.05	-1.74	0.31	3.54	-1.97
4	Target Income @ 6.7% RORB	$76,558,568	$41,675,691	$7,513,780	$1,752,949	$10,220,918	$498,245	$5,295,881	$12,875	$8,258,986	$1,575	$592,146	$654,846	$80,677
5	Actual Income	$76,558,568	18,597,972	8,012,174	1,807,082	27,154,963	674,931	9,627,748	23,909	8,686,980	-2,735	182,580	2,317,562	-158,885
6	Change	-$365,712	$23,077,719	-$498,394	-$54,134	-$16,934,045	-$176,686	-$4,331,867	-$11,034	-$427,994	$4,311	$409,566	-$1,662,716	$239,561
7	Tax Adjusted Change		$14,218,183	-$307,060	-$33,352	-$10,433,065	-$108,856	-$2,668,863	-$6,798	-$263,687	$2,656	$252,334	-$1,024,399	$147,594
8	Revenue Change Needed		$37,295,901	-$805,454	-$87,485	-$27,367,110	-$285,542	-$7,000,731	-$17,832	-$691,682	$6,967	$661,900	-$2,687,115	$387,155
9	Percent Revenue Change Needed		18.6%	-2.0%	-0.9%	-33.1%	-7.7%	-19.3%	-23.2%	-1.3%	50.6%	29.3%	-61.2%	335.1%

SCHEDULE KM-5 HAS BEEN DEEMED

HIGHLY CONFIDENTIAL IN ITS ENTIRETY