Exhibit No.:	
Issue:	Class Cost of Study, Revenue Allocation, Rate Design
Witness:	Kavita Maini
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2019-0374
Date Testimony Prepared:	January 29, 2020

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-2019-0374** Tariff No. YE-2020-0029

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

January 29, 2020

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-2019-0374

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-2019-0374

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 29th day of January, 2020

AMY PANGERC
NOTARY PUBLIC
STATE OF WISCONSIN

Amy Pangerc
____
Notary Public

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

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**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 28 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. 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 Advisory and Planning Advisory Committees.

Q. HAVE YOU PARTICIPATED IN UTILITY RELATED PROCEEDINGS?

A. Yes, I have testified before a number of state regulatory commissions, including in Wisconsin, Minnesota, Missouri, Iowa, North Dakota and South Dakota. I have testified on a variety of issues related to revenue requirements, resource planning and generation resource acquisition, cost of service, revenue allocations and rate design. I have also provided technical comments in Federal Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO-related activities. **KM Schedule -1** identifies the regulatory proceedings in which I have been involved.

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 a corporation representing the interests of large commercial and industrial customers taking service from Empire District Electric Company, A Liberty Utilities Company ("Liberty-Empire" or "Company") on its Large Power/Special Transmission rate schedules.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to discuss and provide recommendations regarding the Company's: (a) class cost of service study ("COSS"); (b) an appropriate allocation approach for any rate change; and (c) 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: Importance of competitive industrial rates

Section IV: Class Cost of Service Study

Section V: Revenue Requirement Allocation

Section VI: Large Power / 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: Importance of Competitive Industrial Rates

a) Many of the companies represented by MECG operate energy intensive facilities that are sensitive to energy cost increases, which affect their overall cost of doing business (page 7).

b) Competitive industrial rates are an important factor in influencing Missouri manufacturers' ability to compete on a regional and national level, which, in turn, impacts the economic health of the state. Large companies not only provide jobs in the Empire service area, but the existence of a competitive industrial base helps to keep all rates lower than they otherwise would be. The Commission recognized this fact in its decision in the 2014 Empire case (pages 7-9).

c) Liberty-Empire's average industrial rates are 21% higher than the national average. Five years ago, they were approximately 17% above the national average, which would suggest that Empire's average industrial rates are declining in competitiveness (page 9).

Section IV: Class Cost of Service Study ("COSS")

a) A COSS study is the linchpin in establishing fair and reasonable rates because it, (i) guides how the revenue requirement should be allocated to classes and (ii) informs rate design. Thus, it is important that the CCOSS approach reflect cost causation (pages 10-14);

b) Empire's load profile characteristics indicate that it is a summer and winter peaking utility. For Empire, these 6 peak months during the summer and winter drive generation infrastructure decisions and should be used to derive the allocators for fixed production plant costs (pages 14-18);

c) Either the coincident peak method or the A&E method are reasonable allocation methods for fixed production plant related costs (pages 18-19);

d) The A&E approach considers the load profile of customer classes by incorporating the class' maximum demands, load factor and average energy use. Therefore, the A&E approach is reasonable method to use in this case. I recommend the A&E 6NCP allocator for allocating fixed production plant to customer classes (pages 19-22);

e) When designing primary and secondary distribution feeders, utilities ensure that sufficient conductor and transformer capacity is available to meet the maximum customer loads at the primary and secondary distribution service levels, whenever the maximum demands occur. I recommend the class 1 NCP allocator for such costs (pages 22-23);

f) Interruptible customers, such as the customer in the SC-P class, forgo firm service and help the utility to avoid building or acquiring generation capacity thereby providing benefits to the entire system. I recommend that this class' base revenues be firmed up to properly match with cost allocation of all fixed production plant related costs. The rate of return under present rates should be calculated for this class after this adjustment is made (pages 23-27).

g) Consistent with Section 393.1640.2, I recommend the revenue allocator for allocating economic development rate discounts pursuant to SB 564 (pages 28-29).

h) While the magnitude varies, the results of my COSS are directionally consistent with that of the Company and confirm that at present rates, the residential and some lighting classes are paying rates that are substantially below cost responsibility. All other classes are above cost (pages 29-30).

Section V: Revenue Requirement Allocation

a) The COSS should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Such an approach will foster equity amongst classes and encourage economic efficiency. While other factors such as gradualism and rate continuity may also be considered, these factors should not be the dominating elements such that there is limited to no movement towards class cost responsibility and certain classes continue to be chronically subsidized by other classes (pages 30-31).

b) Recognizing that it was inequitable for other classes including the LP class to continue to subsidize the residential class, the Commission ordered 25% positive revenue neutral adjustments to the residential class in the 2014 case and similar amounts again in the 2016 case in order to more quickly eliminate subsidies. Lack of updating of base rates since then has resulted in a substantial subsidy to this class. At present rates, the revenues for the residential class needs to increase by approximately 17% to align with its costs to serve (pages 31-34).

c) These results are of concern especially because the Company's average industrial rates are not competitive. Closer alignment of the industrial classes' revenue responsibility with cost responsibility will go a long way in restoring competitiveness and help to push the Company's industrial rates down towards the national average. The lower the rate increase or if there is a rate decrease, the higher should be the revenue neutral adjustment (pages 34-35).

Section VI: Large Power / SC-P Rate Design

a) LP Class: I recommend that if a rate increase is allocated to this class, the increases should be applied proportionally to the billing demand and facility charges, after adjusting the customer charge as proposed by the Company. There should be no change in the energy charges. If a rate decrease is allocated to this class, the decrease should be allocated equally between both blocks of the energy charge to further correct the over recovery of fixed costs from the energy charges (page 36).

b) SC-P Class: The Company's revenue allocation to this class needs to be corrected because of the treatment of interruptible credits and essentially results in the class paying for the credits it receives. I recommend that the Company submit corrected allocation for this class in particular, in rebuttal testimony (page 37).

III. IMPORTANCE OF COMPETITIVE INDUSTRIAL RATES

Q HOW ARE THE COMPANIES REPRESENTED BY MECG IMPACTED BY THIS PROCEEDING?

A This proceeding is of particular importance to MECG companies served under the SC-P and LP rate schedules because it provides the much needed opportunity to address the misalignment of rates with costs to serve. The COSS and base rates have not been updated since 2016 in Case No. ER-2016-0023.

As discussed later in my testimony, the current COSS results based on proper cost causative principles show that the SC-P and LP rates are significantly greater than the Company's cost to serve those classes. Aggressive steps are needed to reduce the above cost burden for these classes, which will not only promote equity among customer classes, it will also help improve the competitiveness of the Company's industrial rates.

Q WHY ARE COMPETITIVE INDUSTRIAL RATES IMPORTANT?

A I am advised that many of the companies represented by MECG 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. For particularly those businesses with facilities in many locations throughout North America (as is true of many of companies represented by MECG), competitive rates are often central to a manufacturer's decision to reduce production, or expand production, at a particular facility. As such, rate disparity among sister plants or competitors has the potential to result in reducing production or shifting production elsewhere, especially if such disparity is sustained over time. Competitive rates are, therefore, important to Missouri's economy and the decisions in this case may determine whether industrial customers become more or less competitive.

Q ARE COMPETITIVE INDUSTRIAL RATES BENEFICIAL TO THE OTHER EMPIRE CLASSES?

A Yes. Not only do large companies provide jobs in the Empire service area, but the existence of a competitive industrial base helps to keep all rates lower than they otherwise would be. The Commission recognized this fact in its decision in the 2014 Empire case.

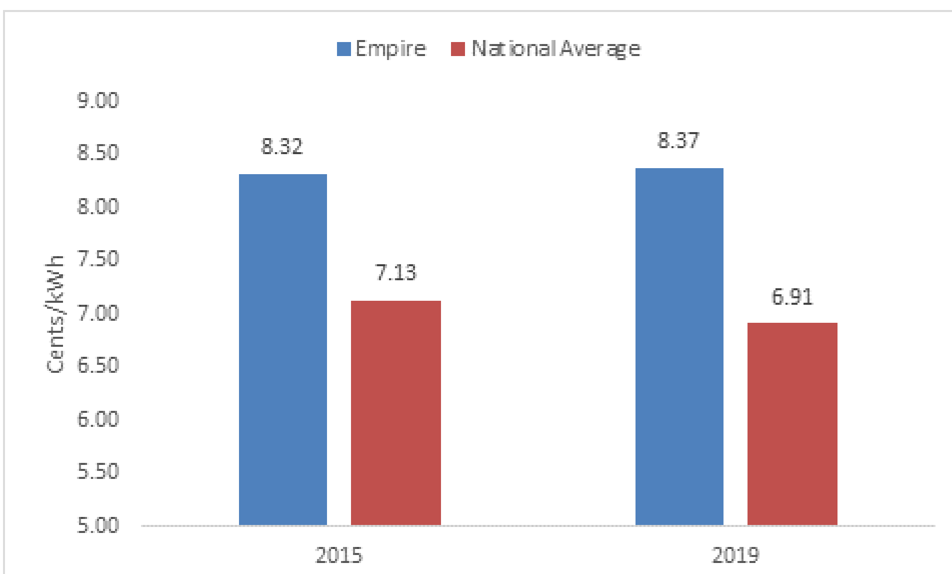
> Competitive industrial rates are important for the retention and expansion of industries within Empire's service area. If businesses leave Empire's service area, Empire's remaining customers bear the burden of covering the utility's fixed costs with a smaller amount of billing determinants. This may result in increased rates for all of Empire's remaining customers.[1]

[1] Report and Order, Case No. ER-2014-0351, issued June 24, 2015, page 18.

Q HOW DO LIBERTY-EMPIRE'S INDUSTRIAL RATES COMPARE TO RATES FROM ELSEWHERE?

A Based upon data provided by the Edison Electric Institute, the Company's average industrial rate is among the highest in the Midwest and Mountain states.[2] As of June 30, 2019, Liberty-Empire's average industrial rates are the 12th highest of the 95 investor owned utilities serving customers in 28 states. **Schedule KM-2** shows a map of the states covered and average industrial rates by investor owned utilities from the highest to the lowest. I also compared the Company's average industrial rate to the national average and found that Liberty-Empire's industrial rates are 21.1% above the national average (See Figure 1). Five years ago, in 2015, the Company's average industrial rate was 16.7% above the national average. Therefore, not only are the current rates high, they appear to have declined in their competitiveness.

Figure 1: Average Industrial Rate Comparisons – 2015 v. 2019



[2] EEI Typical Bills and Average Rate Report, Summer 2019.

IV. CLASS COST OF SERVICE STUDY

A. Importance of A Utility's Cost of Service Study

Q WHAT IS THE IMPORTANCE OF A UTILITY'S COST OF SERVICE STUDY?

A. A utility's cost of service study is the fundamental basis for establishing just and reasonable rates in the ratemaking process. The cost of service study helps determine a utility's revenue requirement, guides revenue allocation to classes and informs rate design.

Revenue Requirement: A utility's cost of service is used in the determination of the revenue requirement of the utility and whether an increase, decrease or no change is necessary. Efforts are made to align the rate revenues to equal the utility's cost of service.

Revenue Allocation to Classes: Given a certain revenue requirement, a utility's cost of service guides the manner in which a given revenue requirement should be allocated to classes. The level of the revenue requirement for each class is based on each class providing the same or equal rates of return.

Setting Rates: For a certain revenue allocation to each class, a utility's cost of service also informs the design of rates in that it helps set the rates with the goal of providing pricing signals to customers and recovering the costs to serve the customers in a particular tariff.

Q FOR A GIVEN REVENUE REQUIREMENT, WHAT IS THE IMPACT OF CLOSELY ALIGNING RATES WITH COSTS TO SERVE?

A. Provided that the class cost of service study is properly developed to reflect cost causation, closely aligning rates with costs to serve fulfills the important goals of promoting equity among classes and encouraging economic efficiency.

Q PLEASE EXPLAIN HOW EQUITY IS PROMOTED AMONG CLASSES.

A. If revenues are allocated to classes and align with the class cost responsibility resulting from a properly developed cost of service study, equity is maintained because each class pays its fair share of costs. To maintain the equity principle, a class not paying its fair share should receive an above system average increase while a class paying more than its fair share should receive a below average increase. In cases where the class revenues are significantly misaligned with cost responsibility, as is the case in this proceeding, larger corrections or adjustments may be warranted in order to restore equity among classes.

Q. HOW IS ECONOMIC EFFICIENCY ACHIEVED?

A. If retail rates align with costs to serve, they provide accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs. If 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. Failure to do so ultimately results in adverse consequences and higher costs for all customers.

In instances where the class revenue responsibility is set above cost, say for the industrial class, the resulting rates will be set at artificially high levels to meet the above cost revenue responsibility. Such rates would incent customers in this class to reduce production or shift production elsewhere. Such a consequence results in higher costs for all customers since the utility's fixed costs would need to be recovered from lesser billing determinants. On the other hand, for classes where rates are set at artificially low levels, such as Empire's residential class, that class is not sent the appropriate price signals which would otherwise provide a greater incentive to customers to engage in energy efficiency measures.

In instances where the class revenue responsibility is at costs to serve but rates are designed such that there is recovery of fixed costs through volumetric charges, the pricing signals are distorted and have the potential once again of increasing costs for all customers. For example, if fixed generation costs are recovered through variable 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 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 the case. Such a signal could then result in customers choosing to use less energy but contributing more to peak conditions. This has the effect of increasing the need for capacity thereby increasing system costs, which once again, must be recovered from customers through higher rates.

B. COSS Steps

Q. WHAT ARE THE DIFFERENT STEPS INVOLVED IN THE COST OF SERVICE PROCESS?

A. A cost of service study generally follows three basic steps. First, the various costs are identified as production, transmission and distribution (functionalization step). Next, these functionalized costs are classified as either demand-related; energy-related; or customer-related (classification step). Finally, these classified costs are allocated among the various rate classes in accordance with the class contribution to the total system cost (allocation step).

Functionalization: Various costs are separated according to function such as generation, transmission, distribution, customer service and administration. To a large extent, this is done in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts.

Classification: The functionalized costs are classified based on the components of utility service being provided and the underlying cost causative factors. As described by the NARUC Manual, the three principal cost classifications are: (1) demand costs (costs that vary with the kW demand imposed by the customer), (2) energy costs (costs that vary with energy or kWh that the utility provides), and (3) 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 allocators measure the class contribution to the total system cost.

Each of the three steps – functionalization, classification and allocation, 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 economically inefficient pricing signals in rate design.

C. COSS Analysis

Q DID YOU USE THE COMPANY SPONSORED EXCEL SPREADSHEET COSS MODEL AS A STARTING POINT FOR YOUR ANALYSIS?

A Yes, however, I used revised allocators for allocating (a) fixed production plant related costs as well as (b) certain primary and secondary distribution demand related costs in the Company's COSS. I also address the treatment of the interruptible load from the SC-P class as well as the appropriate allocation of economic development discounts provided pursuant to SB564. I will further address the issues related to the Company's COSS methodology in my rebuttal testimony.

1. Fixed Production Plant Allocation

Q WHAT ARE FIXED PRODUCTION PLANT RELATED COSTS?

A Fixed production plant related costs are costs that are functionalized as generation related and incurred in acquiring or procuring generation resources. Primarily, these costs consist of the investment in power plants. These costs include return on and of investment and fixed operations and maintenance costs. These functionalized costs are classified as demand related because they are (a) incurred to serve the maximum demands imposed on the system and (b) are fixed in nature in that they do not vary with energy usage.

Q WHAT SHOULD BE CONSIDERED IN DETERMINING THE APPROPRIATE ALLOCATOR FOR FIXED PRODUCTION PLANT RELATED COSTS?

A In order to determine the appropriate allocator, it is necessary to identify the underlying cost causative driver behind generation resource acquisition decisions. Since these costs are primarily incurred and the generation sized to meet system peak demand, the most important factor is the annual load pattern of the utility. Since production plant must be sized to meet the maximum load or demand imposed on these facilities, the appropriate allocation method should reflect the load characteristics of the utility. For example, if a utility is summer peaking, then each class' contribution to the summer peaks is an appropriate cost causative allocator. If a utility is summer and winter peaking, like Empire, then the allocation method must consider the class demands imposed in both of these seasons. For a utility with non-seasonal load patterns or a high load factor, demands in all months and related class contributions may be relevant.

Q DID YOU ANALYZE LIBERTY- EMPIRE MISSOURI'S SYSTEM LOAD?

A Yes, I did. I looked at historical data for the Company's Missouri retail system load for the period 2015-2017. Figure 2 shows that both a summer and winter peak exists for Empire. In two years, Empire showed a winter peak, while in one of the three years, the system peaked in the summer. Further, Figure 3 shows that the seasonal peak is 93% to 97.5% of the annual system peak.

Figure 2: Liberty-Empire's Missouri System Peaks: 2015-2017

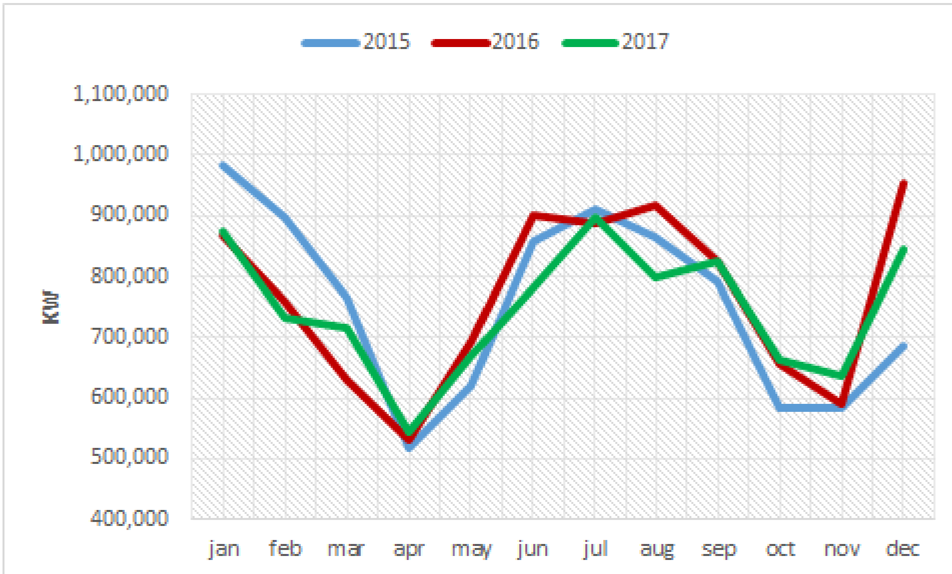
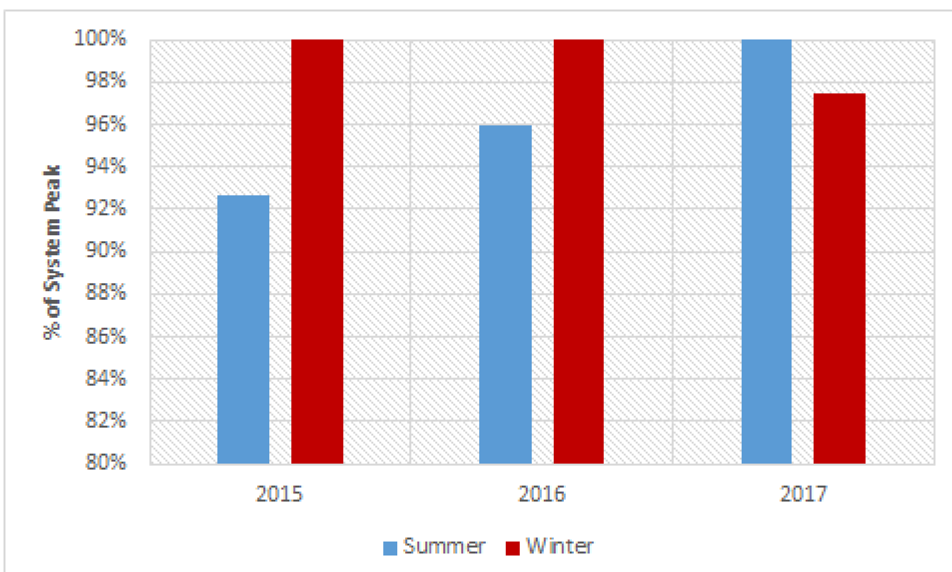
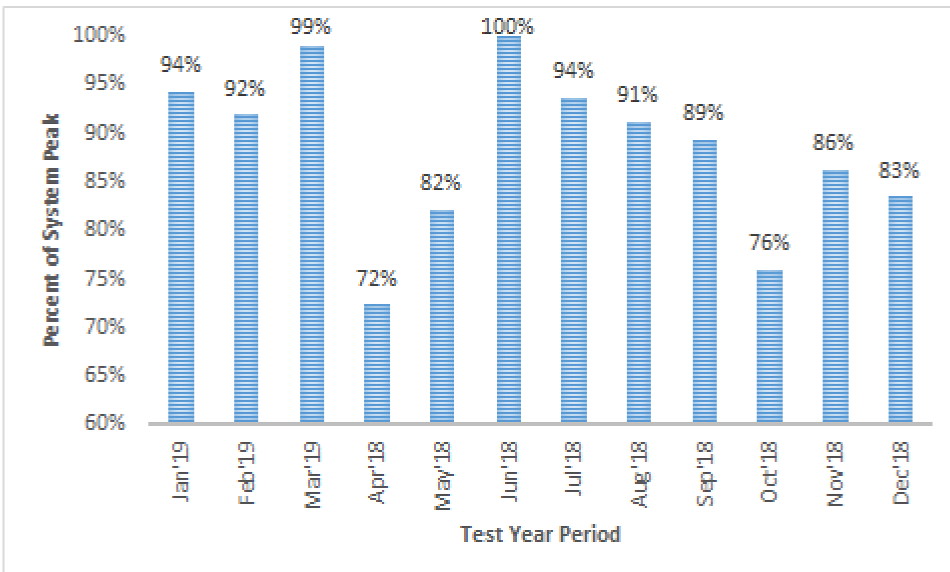


**Figure 3: Liberty-Empire's Missouri's Seasonal Peak
As a Percent of System Peak: 2015-2017**



The data for the test year in this case shows a similar seasonal pattern. Figure 4 shows the system monthly peaks as a percent of overall system peak for the test year. This chart shows that, for the test year, the system peaked in June with the second highest peak in March at 99% of the annual system peak. Since generation capacity is sized to meet the system peak and given the seasonal pattern, class contributions to these two peaking months could be considered the appropriate cost causers.

Figure 4: Liberty-Empire Missouri's Monthly Peak Demands As a Percent of Annual Peak [3]



However, to be conservative, it makes sense to consider summer and winter peaks that are within 10% of the Company's annual Missouri system peak. The monthly peak demands in July and August are 91% and 94% of the system peak while the monthly peak demands in January through March range between 92% and 99% of the system peak respectively. Thus, 3 summer peaks (June through August) and 3 winter peaks (January through March) capture the predominant seasonal peak months respectively.

[3] Demand Data source: Mr. Timothy Lyons COSS model (demand data tab, Table:12 Month CP at Generation).

The rest of the months are of much less significance and do not drive Empire's decision to build more generation infrastructure. Since these months do not drive the utility's decision to build or size generation additions, they should not be considered in determining cost causation or the resulting cost allocation to classes. Doing so would fail to recognize the primary cost driver for acquiring generation capacity and under-allocate the costs to the cost-causing weather sensitive loads.

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.

In the Coincident Peak Demand method, the fixed production plant costs are allocated to rate classes solely on demand factors that measure the class contribution to system peak or peaks.

In contrast, the A&E methodology considers both demand as well as class energy usage. The A&E Demand method consists of an average demand component and an excess demand component. The average demand component 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 class' maximum non-coincident peak or peaks and the average demand. The average demand component for each class is weighted by the system 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 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 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 using the class coincident peaks during the peak months for the coincident peak method or utilizing class non-coincident peaks during the peak months for the A&E method would be reasonable approaches.

Q WHICH ALLOCATION METHOD DO YOU RECOMMEND IN THIS CASE?

A Like Empire and all of the Missouri utilities, I recommend the A&E demand method. While Empire considered 12 non-coincident peaks in this case, I rely on the non-

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

coincident peaks experienced during three summer months (June through August) and three winter months (January through March) ("A&E 6NCP").

With respect to these non-coincident peaks, the six months of June-August and January-March represent the summer and winter peak periods respectively and reflect cost causation regarding generation plant infrastructure decisions. These months are the primary driver of capacity needs and were therefore used to determine the cost allocation to classes. Specifically, I calculated the excess portion using the non-coincident peaks from these six peaking months.

Q PLEASE EXPLAIN HOW YOU DERIVED THE AED6NCP ALLOCATOR.

A Figure 5 shows the derivation of the A&E 6NCP allocator.

Figure 5: Derivation of the A&E 6NCP Allocator

Column	1	2	3	4	5	6	7
	Peak Demand	Energy Sales	Average	Excess	Average	Excess	Total
	6 NCP	with Losses	Demand	Demand	Demand	Demand	Allocator
Rate Class	(KW)	(kWh)	(KW)	(KW)	(%)	(%)	(%)
RG-Residential	555,082	1,795,766,369	204,996	350,086	39.90%	58.82%	49.86%
CB-Commercial	87,696	340,118,907	38,826	48,869	7.56%	8.21%	7.90%
SH-Small Heating	23,644	91,300,331	10,422	13,222	2.03%	2.22%	2.13%
GP-General Power	188,648	930,539,065	106,226	82,422	20.67%	13.85%	17.08%
SC-P PRAXAIR Transmission	8,426	71,915,586	8,210	216	1.60%	0.04%	0.78%
TEB-Total Electric Bldg	83,690	384,856,858	43,933	39,756	8.55%	6.68%	7.57%
PFM-Feed Mill/Grain Elev	200	451,386	52	149	0.01%	0.03%	0.02%
LP-Large Power	149,874	847,092,535	96,700	53,174	18.82%	8.93%	13.61%
MS-Miscellaneous	18	149,208	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,805	24,077,589	2,749	3,056	0.53%	0.51%	0.52%
PL-Private Lighting	4,667	13,882,074	1,585	3,082	0.31%	0.52%	0.42%
LS-Special Lighting	1,277	825,400	94	1,182	0.02%	0.20%	0.11%
Total	1,109,026	4,500,975,308	513,810	595,216	100.00%	100.00%	100.00%

Column 1 shows the average of the six non-coincident peaks ("NCP") for the peaking months by class. Column 2 shows the annual energy (kWh) by class and Column 3 shows the average demand calculated by dividing the annual energy usage by 8,760 (number of hours in a year). The excess demand shown in Column 4 is calculated by subtracting the average demand in Column 3 from the average of the 6 NCP in Column 1. Column 5 shows each class' average demand as a percentage of the system average demand while Column 6 shows each class' excess demand as a percentage of the total excess demand for all classes. Column 7 represents that sum of (a) weighting class average demand as a proportion to the system average demand (Column 5) by the load factor (47.35%) and (b) weighting the class excess as a proportion to the total excess demand (Column 6) by 1 minus the load factor (52.65%). This method is consistent with the NARUC manual.

The total allocator calculated in Column 7 of Figure 5 is used to allocate fixed production plant costs to the classes. For example, based upon this methodology, the residential class should be allocated 49.86% of the total fixed production plant related costs, while the GP and LP classes should be allocated 17.08% and 13.61% of these costs respectively.

Q WHAT INSIGHTS CAN BE GAINED FROM FIGURE 5?

A The class average and excess demand shares provide important insights regarding the relative variability in each class' load profile. Classes with higher variability use the system less efficiently, are generally weather sensitive and cause demand on the system to hit peaks. From a relative standpoint, classes with excess demand percentage shares (Column 6 in Figure 5) that exceed their respective average demand percentage shares (Column 5 n Figure 5) have higher variability in their load profile. Conversely, classes with average demand percentage shares higher than their excess demand shares have lesser variability and utilize the system more efficiently.

2. Allocation of primary and secondary distribution costs

Q WHAT ARE DISTRIBUTION PLANT RELATED COSTS?

A Distribution plant related costs are costs that are functionalized as distribution related in COSS and incurred for infrastructure used to reduce high-voltage energy from the transmission system to lower voltages for delivery to customers. The distribution system associated with equipment designated under FERC accounts 364-368, such as poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices and line transformers, are classified as both customer and demand related. Utilities typically utilize a minimum size system approach to recognize the dual function of the these facilities: being capable of delivering service to customers (customer related costs) and ensuring that the distribution system is large enough to provide reliable service (demand related costs).

Q HOW SHOULD THE PRIMARY AND SECONDARY DISTRIBUTION PLANT COSTS FOR FERC ACCOUNTS 364-368 THAT ARE CLASSIFIED AS CUSTOMER RELATED BE ALLOCATED?

A Since the underlying cost causative factor is customer related, the allocation should be based on each class' percentage of the total number of customers. In this regard, I used the same allocator as the Company.

Q HOW SHOULD THE PRIMARY AND SECONDARY DISTRIBUTION PLANT COSTS FOR FERC ACCOUNTS 364-368 THAT ARE CLASSIFIED AS DEMAND RELATED BE ALLOCATED?

A When designing primary and secondary feeders, utilities ensure that sufficient conductor and transformer capacity is available to meet the maximum customer loads at the primary and secondary distribution service levels, whenever the maximum loads or demands occur. The Class 1 NCP, that is each class' single largest peak during the test year, is an appropriate allocator and recognizes the fact that by sizing the distribution system to meet each class' maximum demand, the system is able to reliably serve the load throughout the year. Using the average of 6 class NCPs as the Company proposed in this case, necessarily dilutes the cost causative factor (i.e., the maximum class NCP demand) that drives the sizing of the distribution facilities. As I will discuss in my rebuttal testimony, I note that the Company used the class 1 NCP allocator in its COSS submitted in Docket No. ER-2014-0351. Also, it is my understanding that Ameren-Missouri also utilized this same allocator in the current case (Docket No. ER-2019-0335). I used the class 1NCP allocator in my COSS analysis.

3. Firming Up SC-P Class Revenue At Present Rates

Q. HOW DOES THE SC-P CLASS' INTERRUPTIBLE LOAD BENEFIT THE SYSTEM?

A. Interruptible customers, such as the single customer in the SC-P class, forgo firm service and help Empire to avoid building or acquiring generation capacity thereby providing benefits to the system. For the single customer in the SC-P class, the vast majority of the customer's load is interruptible. Since load on interruptible service can and is available to be interrupted, the Company does not have a capacity obligation for this load. According to SPP rules, utilities must have enough capacity to serve <u>firm</u>

load plus a 12% planning reserve margin requirement. Figure 6 is taken from SPP's 2019 resource adequacy report[5] and shows that interruptible load (called Controllable and Dispatchable DR) for Liberty-Empire (on a total company basis) is deducted from the forecasted demand before calculating the planning reserve margin requirement. Thus, because of the existence of this interruptible load, the Company avoids procuring an additional 8.96 MW of capacity it would have otherwise needed to procure, due to the interruptible load (8 MW + planning reserve margin of 12%).

In return for providing interruptible service, customers with such load receive an interruptible credit. 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.

Figure 6: Liberty – Empire's Planning Reserve Margin Requirements Summary

Capacity Summary	Unit	2019
Capacity Resources	MW	1,383
Firm Capacity Purchases	MW	59
Firm Capacity Sales	MW	0
External Firm Power Purchases	MW	0
External Firm Power Sales	MW	0
Confirmed Retirements	MW	0
Total Capacity	**MW**	**1,442**
Demand Summary		
Forecasted Peak Demand	MW	1,130
Internal Firm Power Sales	MW	0
Internal Firm Power Purchases	MW	0
Controllable and Dispatchable DR	MW	8
Controllable and Dispatchable BTM Gen	MW	0
Net Peak Demand	**MW**	**1,122**
Requirements Summary		
Resource Adequacy Requirement	**MW**	**1,256**
Excess Capacity	MW	186
Deficient Capacity	**MW**	**0**
LRE planning reserve margin	%	28.57
Planning Reserve Margin	%	12.00

[5] https://www.spp.org/documents/60096/2019%20spp%20june%20resource%20adequacy%20report.pdf

Q HOW SHOULD SC-P CLASS' INTERRUPTIBLE LOAD BE TREATED IN THE COSS?

A Since capacity is not built to meet interruptible demand, the demand allocator used to allocate fixed production plant related costs should exclude interruptible load.[6]

Q HOW DID YOU ACCOUNT FOR THE INTERRUPTIBLE LOAD IN THE SC-P CLASS?[7]

A In this case, in order to narrow the issue, I included all of the SC-P class load as if it were firm thereby allocating more fixed production plant related costs to this class than is appropriate. 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 and planning reserve margin requirements. The rate of return, however, was calculated, outside the COSS model, using revenues prior to subtracting the interruptible credit. Thus, revenues for the class, under this approach are also treated as if service was firm and not interruptible. Since the Company proposes to voluntarily impute the difference in revenue and not allocate the cost of the interruptible credit to other classes, I did not make any other adjustments in terms of allocation to classes. Should the Company decide to submit a revised proposal in its rebuttal testimony and allocate the costs of the interruptible credits to customers, I provide some recommended adjustments further below.

[6] For example, in docket ER-2016-0023, while the Company did not refresh its COSS from the prior case, it proposed to not allocate Riverton conversion costs to the SC-P class. This approach appropriately recognized that capacity costs are invested for the purpose of meeting firm peak demand, and that the Company does not procure capacity for interruptible customers. See Kavita Maini Direct Testimony in Docket No: ER-2016-0023.

[7] There is a small amount of interruptible load in the GP class. Given the modest amount, I did not make any changes to the Company's approach.

Q PLEASE EXPLAIN WHY THE PRESENT REVENUE NEEDS TO BE FIRMED UP FOR THE SC-P CLASS?

A Since all the fixed production plant related costs were allocated to interruptible load as though it is receiving firm service, the base revenues need to be firmed up to match up the revenues with the costs. Failure to do so would result in a mismatch between revenues and costs for such load because, for costing purposes, the treatment assumes that interruptible load is receiving firm service. However, the revenues are net of the interruptible credit. This mismatch would result in under estimating the rate of return earned from the SC-P class and essentially implies that interruptible load is paying for the interruptible credit it receives, for taking non-firm service.

Q DO YOU HAVE ADDITIONAL COMMENTS REGARDING ALLOCATION OF COSTS ASSOCIATED WITH INTERRUPTIBLE CREDITS?

A Yes. In response to MECG 2.4, the Company provided a revised allocation proposal of costs associated with the interruptible credits with the SC-P class instead of voluntarily imputing the difference in revenue. The revised proposal consists of allocating the costs of the interruptible credits to all customers using the Company's A&E 12 NCP allocator, outside of the COSS model and in calculating the proposed increases by class.

Since interruptible load provides system wide benefits by reducing the need for capacity, I support the proposal to recover the interruptible credit related costs from customers. However, should the Company decide to submit this proposal in its rebuttal testimony, the Company must develop a revised A&E allocator that excludes interruptible load, when allocating the interruptible credit related costs to classes outside of the COSS model. Since customers providing interruptible service do not cause interruptible credit related costs to be incurred, such costs should not be allocated to the interruptible load portion of these customers. Therefore, consistent with cost causation, the cost of the interruptible credits should be allocated to firm load only. Further, as discussed earlier, current base revenues should be firmed up to be consistent with the matching principle (to match with the allocation of all fixed production related costs in the COSS) in order to calculate the rates of return at present rates.

Q HAVE YOU DEVELOPED A REVISED A&E ALLOCATOR TO REFLECT THE ALLOCATION OF THE INTERRUPTIBLE CREDIT RELATED COSTS TO FIRM LOAD ONLY?

A **Schedule KM-3** page 1 shows the calculation of the A&E 6NCP allocation excluding interruptible load from the GP and SC-P class. This Schedule is calculated in the same manner as the A&E 6NCP allocator shown in Figure 5 except that the interruptible load has been removed from the relevant classes. Schedule KM-3, page 2 shows the adjusted current base revenues after firming them up and allocating the costs of the interruptible customers to firm load in the various customer classes.

4. Economic Development Rate Discounts Pursuant To SB564 ("SBEDR")

Q WHAT ARE THE SBEDR DISCOUNTS?

A In 2018, the General Assembly enacted SB564. As part of that legislation, companies that locate or expand a facility in Missouri can receive, for a five year period, a discount that averages to 40%. Section 393.1640.2 promulgates the manner in which the costs associated with these discounts should be allocated:

> In each general rate proceeding concluded after August 28, 2018, the reduced level of revenues arising from the application of discounted rates provided for by subsection 1 of this section shall be allocated to all the electrical corporation's customer classes, including the classes with customers that qualify for discounts under this section. This increase shall be implemented through the application of a uniform percentage adjustment to the revenue requirement responsibility of all customer classes.

Q HOW DID THE COMPANY ALLOCATE SBEDR DISCOUNT RELATED COSTS TO CLASSES?

A In response to MECG 2.2, the Company indicated that it allocated SBEDR discount related costs using FERC account 908 allocator. This allocator is generally used to allocate customer assistance related costs and does not result in the discounts being allocated among the classes as a "uniform percentage adjustment". In a following supplemental response, the Company indicated that it will revise the allocation because the current method (the Account 908 allocator) is not consistent with the statutory provisions in Section 393.1640.2. The Company proposes to instead use the revenue allocator to comply with the statute. The SBEDR amount in the COSS is $60,389, which is also reflected as adjustment 23 on page 21 of Ms. Sheri Richards' direct testimony.

Q DO YOU SUPPORT THIS REVISED ALLOCATION APPROACH?

A Yes. It should be made certain, however, that the correct amount of SBEDR related discounts are being allocated to classes. I am in the process of issuing additional discovery in this regard and will update my testimony in following rounds of testimony.

Q IN SUMMARY, WHAT ARE THE CHANGES YOU MADE TO THE COMPANY'S COSS?

A I made the following adjustments in order to more closely align the cost allocation to classes with the underlying cost causative drivers:

- I used the A&E 6NCP allocator for allocating fixed production plant related costs to classes; and
- I used class 1 NCP to allocate primary and secondary distribution plants related costs classified as demand related.
- Outside of the COSS model, I firmed up revenues for the SC-P class.

Q WHAT DO THE RESULTS OF YOUR COSS INDICATE?

A **Schedule KM-4** shows a summary of the COSS results at present rates. For comparison purposes, Figure 7 compares, at present rates, the earned rate of return ("ROR") and the indexed rate of return derived from my study as well as the Company's COSS. The results from both studies demonstrate that, from a directional standpoint, the residential and some lighting classes produce a ROR below the system ROR. This means that these classes are currently paying rates that are below the cost to serve those classes. All other classes produce greater than the system ROR of 6.11% although the magnitude varies. For example, under the MECG COSS, the LP class produces an ROR of 9.52% compared to the Company's result of 8.34%. An important difference is that the ROR for the SC-P class is significantly higher under my results compared to that of the Company. This result is attributable to the appropriate firming up of Schedule SC-P's revenues as discussed earlier.

Figure 7: MECG v. Empire's CCOSS Earned Rate of Return ("ROR") and Indexed ROR by Class at Present Rates

	MECG COSS RESULTS		LIBERTY-EMPIRE COSS RESULTS	
	Earned ROR	Indexed ROR	Earned ROR	Indexed ROR
RG-Residential	2.62%	43	2.90%	48
CB-Commercial	8.16%	134	8.23%	135
SH-Small Heating	7.12%	117	7.39%	121
GP-General Power	12.19%	200	11.44%	187
SC-P PRAXAIR Transmission	15.28%	250	9.63%	158
TEB-Total Electric Bldg	11.37%	186	11.46%	187
PFM-Feed Mill/Grain Elev	10.56%	173	10.59%	173
LP-Large Power	9.52%	156	8.34%	137
MS-Miscellaneous	-4.94%	-81	-5.21%	-85
SPL-Municipal St Lighting	1.99%	33	1.77%	29
PL-Private Lighting	26.48%	433	26.95%	441
LS-Special Lighting	-7.18%	-118	-6.47%	-106
Company	**6.11%**	**100**	**6.11%**	**100**

V. REVENUE REQUIREMENT ALLOCATION

Q WHAT SHOULD BE THE PRIMARY GUIDING PRINCIPLE IN ESTABLISHING FAIR AND REASONABLE RATES?

A As I mentioned earlier, the COSS 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. Also as discussed earlier in my testimony, such an approach fulfills the important goals of promoting equity among classes and encouraging economic efficiency. If revenues are allocated to classes and align with the class cost responsibility, equity is maintained because each class pays its fair share of costs. Further, if retail rates align with costs to serve, they reflect accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs.

Q CAN OTHER FACTORS BE ALSO CONSIDERED?

A Yes. Other factors such as gradualism and rate continuity may also be considered. At the same time, however, these factors should not be the dominating elements such that there is limited to no movement towards class cost responsibility and certain classes continue to be chronically subsidized by other classes.

Q DID THE COMMISSION ADDRESS THE ISSUE OF THE MOVEMENT TOWARDS COST IN PAST CASES?

A Yes. In Docket No. ER-2014-0351, the Commission ordered revenue neutral adjustments to present base revenues prior to an equal percent increase for all classes. A revenue neutral adjustment consists of revenue shifts within classes at present rates, without changing a utility's total system revenues. These adjustments are made to more closely align each class with its cost of service. A positive revenue neutral adjustment is made when the rates for a class result in revenues below costs to serve. Similarly, a negative revenue neutral adjustment is made when the rates for a class result in revenues above costs to serve.

In the 2014 case, the Commission ordered a 25% positive revenue neutral adjustment to the residential class in an effort to more fairly balance rate impacts and equity concerns. That is, the Commission ordered an adjustment to eliminate one fourth of the quantified residential subsidy. The Small Heating (SH), Commercial Building (CB), Large Power (LP), Total Electric Building (TEB), and General Power (GP) rate classes received the off-setting revenue neutral decrease to these classes' revenue. In the following case, ER-2016-0023, the Commission approved a settlement which also included a similar positive revenue neutral adjustment to the residential class and negative neutral adjustments to the GP, LP and SC-P classes.

Since that time however, the Company has not filed a rate case and rates have deviated significantly from cost for all classes.

Q WHAT ARE THE TOTAL REVENUE NEUTRAL ADJUSTMENTS NEEDED BY CLASS TO COMPLETELY ELIMINATE THE CROSS SUBSIDIZATION AT PRESENT RATES IN THIS CASE?

A Figure 8 shows the derivation of the revenue neutral adjustments needed to align revenue responsibility with cost responsibility at present rates. Column 5 shows the net income required to achieve equal ROR. Column 6 shows the difference in income between the net income require to achieve equal ROR (Column 5) and income that produces the current ROR (Column 3). Column 7 shows the revenue neutral changes needed to base rates in order to completely eliminate cross subsidization. As can be observed, in order to bring it completely to cost of service and eliminate any subsidization, the residential class would need a revenue neutral increase of approximately 17% to achieve cost based responsibility, while the LP and SC-P classes would require revenue neutral decreases of approximately 12% and 22% respectively.

Figure 8: Revenue Neutral Adjustments Needed for Equal ROR at Present Rates ($ in Thousands)[8]

	1	2	3	4	5	6	7	8
Rate Class	Base Revenues ($)	Current Rate Base ($)	Net Operating Income ($)	Earned ROR	Income @ Equal ROR ($)	Difference in Incomce ($)	Revenue Change to attain Equal ROR ($)	% Revenue Neutral Increase @ equal ROR
RG-Residential	214,578	788,606	20,675	2.62%	48,183	27,508	36,119	16.83%
CB-Commercial	43,173	124,879	10,193	8.16%	7,630	(2,563)	(3,365)	-7.79%
SH-Small Heating	9,894	30,455	2,169	7.12%	1,861	(308)	(405)	-4.09%
GP-General Power	84,230	215,872	26,319	12.19%	13,190	(13,130)	(17,240)	-20.47%
SC-P PRAXAIR Transmission	4,415	7,923	1,211	15.28%	484	(727)	(954)	-21.62%
TEB-Total Electric Bldg	36,067	96,919	11,021	11.37%	5,922	(5,099)	(6,695)	-18.56%
PFM-Feed Mill/Grain Elev	72	220	23	10.56%	13	(10)	(13)	-17.99%
LP-Large Power	61,613	164,854	15,696	9.52%	10,072	(5,623)	(7,384)	-11.98%
MS-Miscellaneous	14	30	(1)	-4.94%	2	3	4	29.97%
SPL-Municipal St Lighting	2,186	19,173	381	1.99%	1,171	790	1,037	47.46%
PL-Private Lighting	4,065	6,656	1,762	26.48%	407	(1,356)	(1,780)	-43.80%
LS-Special Lighting	132	1,774	(127)	-7.18%	108	236	310	235.23%
	460	1,457,360	89,043	6.11%	89,043			

These results are of concern especially because the Company's average industrial rates are not competitive. Closer alignment of the industrial classes' revenue responsibility with cost responsibility would go a long way in restoring competitiveness and help to push the Company's industrial rates towards the national average

Q DOES THE COMPANY'S PROPOSED REVENUE ALLOCATION RESULT IN MOVING CUSTOMER CLASSES CLOSER TO COST IN A MEANINGFUL MANNER?

[8] Current base revenues are adjusted for the Tax Cuts and Jobs Act (TCJA) related changes as shown in response to MECG 2.4.

A No. The Company's revenue allocation method as described in Mr. Timothy Lyons direct testimony essentially limits rate increases to classes that require large increases based on cost. The Company's proposed revenue allocation results in over moderating the impacts to the residential class. This has the effect of maintaining the substantial subsidization of the residential class by other classes including the SC-P and LP classes. For example, the Company's proposed increase to the residential class is less than 1% higher than the system wide increase. Clearly, since the COSS indicates that the residential class should receive a 17% increase, this means that the revenue neutral adjustments are minimal and other classes will end up substantially subsidizing this class. While I recognize the challenge the Company may have faced in managing competing objectives of bill impacts and equity among classes, it is important to not lose sight of the fact that, while some customers' classes will continue to contribute significantly less than their share of costs under the Company's proposed approach, other classes are being asked to bear the unfair burden of contributing more than their share of costs.

Q WHAT IS YOUR REVENUE ALLOCATION PROPOSAL?

A Similar to past cases, my revenue allocation recommendation consists of making revenue neutral adjustments at present rates. 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. Figure 9 shows the revenue changes needed to present base rates, in amounts and percent, to make 25% and 50% revenue neutral adjustments by class.

Figure 9: Revenue Neutral Adjustments at Present Rates (Dollars in Thousands)

		25%			50%		
Rate Class	Current Base Revenues ($)	Revenue Neutral Change	Adjusted Base Revenue	Revenue Neutral % Change in Current Base Revenues	Revenue Neutral Change	Adjusted Base Revenue	Revenue Neutral % Change in Current Base Revenues
RG-Residential	214,578	9,030	223,608	4.2%	18,059	232,638	8.4%
CB-Commercial	43,173	(841)	42,331	-1.9%	(1,683)	41,490	-3.9%
SH-Small Heating	9,894	(101)	9,793	-1.0%	(202)	9,692	-2.0%
GP-General Power	84,230	(4,310)	79,920	-5.1%	(8,620)	75,610	-10.2%
SC-P PRAXAIR Transmission	4,415	(239)	4,176	-5.4%	(477)	3,938	-10.8%
TEB-Total Electric Bldg	36,067	(1,674)	34,393	-4.6%	(3,348)	32,720	-9.3%
PFM-Feed Mill/Grain Elev	72	(3)	68	-4.5%	(6)	65	-9.0%
LP-Large Power	61,613	(1,846)	59,767	-3.0%	(3,692)	57,921	-6.0%
MS-Miscellaneous	14	1	16	7.5%	2	17	15.0%
SPL-Municipal St Lighting	2,186	259	2,445	11.9%	519	2,704	23.7%
PL-Private Lighting	4,065	(445)	3,620	-10.9%	(890)	3,175	-21.9%
LS-Special Lighting	132	77	209	58.8%	155	286	117.6%

Q WHAT IS YOUR RECOMMENDATION?

A My recommendation is dependent on the magnitude of any revenue change ultimately ordered in this case. As mentioned, the Commission routinely will consider gradualism in deciding the appropriate revenue allocation in a case. Therefore, the lower the rate increase in this case, or if there is a rate decrease, the higher should be the revenue neutral adjustment. It is my understanding that the Company will be filing another rate case soon after this proceeding is complete to request recovery for its wind generation acquisition. Given the capital investment associated with this wind generation, the next rate case may be significant. Therefore, this proceeding provides an opportune time to make significant revenue neutral adjustments to better align rates with cost.

VI RATE DESIGN

Q WHAT IS THE COMPANY'S RATE DESIGN PROPOSAL FOR THE LP CLASS?

A The Company proposes to recover the allocated increase to the LP class by increasing the facility demand charge and customer charges. Therefore, the Company's proposal includes no changes to the billing demand charges or the energy charges. Most of the rate recovery is proposed by increasing the facility demand charges.

Q. WHAT IS YOUR RATE DESIGN RECOMMENDATION FOR THE LP CLASS?

A I recommend the following:

- Unlike the Company, which would apply any rate increase to the customer charge and the billing demand charge, I propose that any increase be applied proportionally to the billing demand and facility charges, after adjusting the customer charge as proposed by the Company. There should be no change in the energy charges. I make this recommendation because the Company indicates (Lyons' direct testimony on pages 35 and 36) a significant under recovery from both the billing demand and facility demand charges, which also suggests that fixed costs are being recovered from the energy charges.
- If a rate decrease is allocated to this class, then I would propose that the decrease be allocated equally between both blocks of the energy charge to further correct the over recovery from the energy charges. In this case, the other charges would remain at current levels.

Q WHAT IS THE COMPANY'S RATE DESIGN PROPOSAL FOR THE SC-P CLASS?

A Mr. Lyons indicates on page 35 of his direct testimony that the recovery of the allocated increase would consist of proportionally increasing all components of the rate applicable to this class. However, the revenue allocation to this class, is problematic and needs to be corrected.

Q PLEASE EXPLAIN.

A This class, consisting of one customer with the majority of the load being interruptible, is essentially being asked to pay for the interruptible credit it receives. The Company's response to MECG 2.4 shows that even by erroneously allocating the interruptible credits related costs to load in all classes including interruptible load, this class should get a decrease under the Company's proposed revenue allocation proposal presented in direct testimony. As discussed earlier, however, the costs should be allocated to firm load only. I recommend that the Company submit corrected allocation and resulting rate design for this class in particular, in rebuttal testimony.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

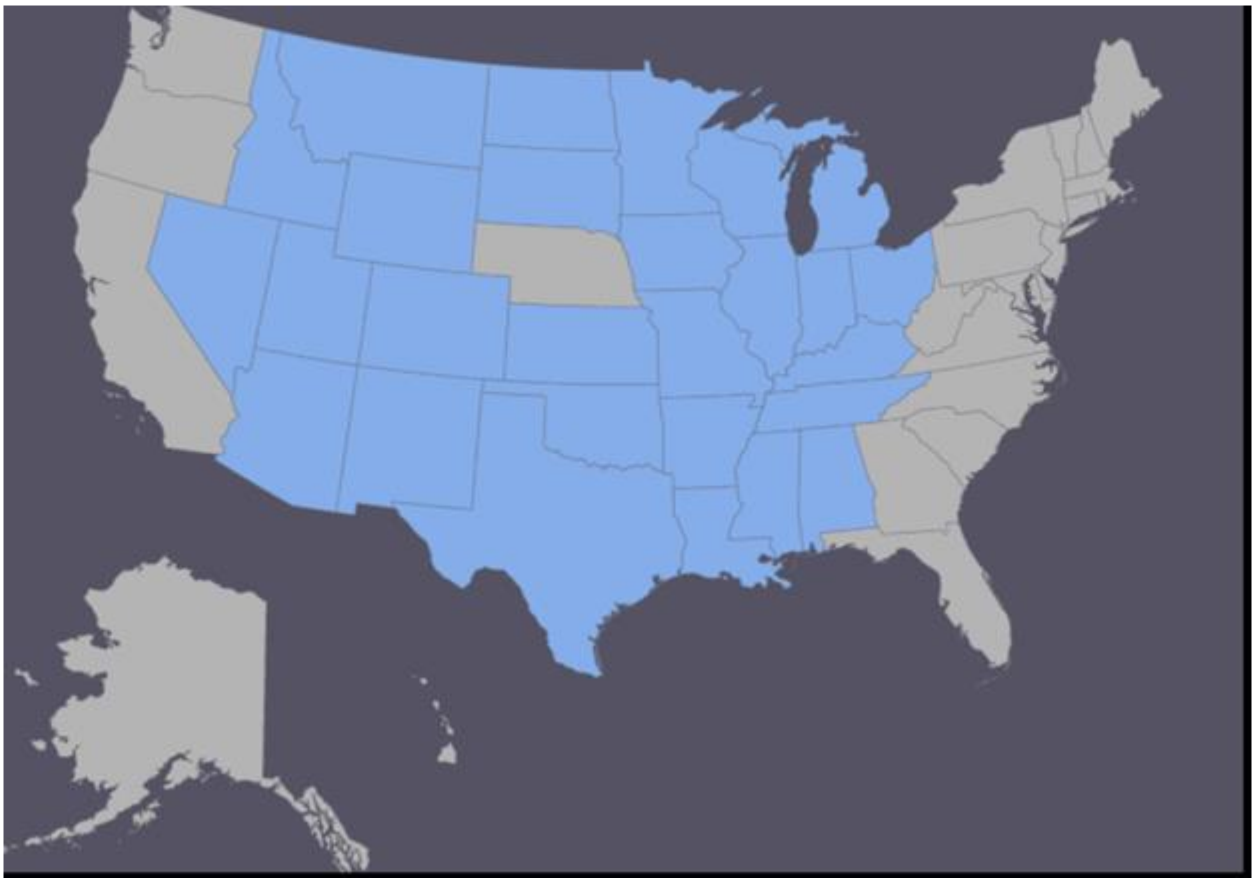
A Yes.

	Docket Number	Type by State/FERC	Major Issues	Role
	Retail Jurisdiction			
		North Dakota		
1	PU-05-131	Otter Tail: Cost of Energy Adjustment Clause	Time of use rate related issues	Expert Witness - Large Industrial Group
2	PU-08-862	Otter Tail: Base Rate Case Application	Revenue Requirement, rate design	Expert Witness - Large Industrial Group
3	PU-08-742	Otter Tail: Renewable Resource Cost Recovery Rider	Revenue Requirement, cost allocation and rate design	Expert Witness - Large Industrial Group
4	PU-11-153;162	Otter Tail: Transmission Cost Recovery Rider	Revenue Requirement, cost allocation and rate design	Expert Witness - Large Industrial Group
5	PU-17-398	OTP Base Rate Case Application	In Progress	Expert Witness - Large Industrial Group
		South Dakota		
6	EL11-019	Xcel Energy Base Rate Case Application	Renewable related revenue requirements	Expert Witness - PUC Staff
7	EL12-027, EL14-082	Otter Tail Petition to Establish an Environmental Quality Cost Recovery Tariff	Evaluation of Big Stone AQCS as a least cost resource	Expert Witness - PUC Staff
8	EL12-062	Black Hills Phase In - Cheyenne Prairie Generating Station	Evaluation of a Combined Cycle Addition - Need and least cost resource	Expert Witness - PUC Staff
9	EL14-058	Xcel Energy Base Rate Case Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
10	EL15-024	MDU Base Rate Case Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
11	EL-021	Complaint filed by Juhl Energy AKA Consolidated Edison regarding avoided cost compensation for wind QFs	Methodology for Avoided Cost	Expert Witness - PUC Staff
12	EL16-037	Commission Staff Motion to Show Cause regarding certain fuel cost recovery through the Fuel Cost Recovery Rider	Prudency of Acquiring Resources	Expert Witness - PUC Staff
13	EL18-004	In the Matter of the Petition of Northern States Power Company dba Xcel Energy for Approval of a Proxy Pricing Proposal to Adjust Certain Fuel Clause Rider Power Purchase Costs	Evaluating Proxy Pricing Methods	Expert Witness - PUC Staff (currently in progress)
14	EL18-021	Otter Tail Power Company Base Rate Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
15	EL19-025	Phase In Rider	Least cost resource evaluation	Expert Witness - PUC Staff
		Minnesota		
16	E002/GR-13-868	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Expert Witness - MN Chamber
17	ER017/GR12-961	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Expert Witness - MN Chamber
18	E017/GR08-1065	Otter Tail Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
19	E002/GR07-1178	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
20	E002/GR10-971	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
21	E001/GR-10-276	Interstate Power & Light Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
22	E-017/M-08-1529	Otter Tail: Renewable Resource Cost Recovery Factor	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
23	E-017/GR09-881	Otter Tail: Transmission Cost Recovery Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
24	E-017/M-09-1484	Otter Tail: Renewable Resource Cost Recovery Factor	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
25	E017/M-10-1061	Otter Tail:Transmission Cost Recovery Rider Annual Adjustment	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
26	E-017/M-10-220	Otter Tail: Update Conservation Improvement Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
27	E017/M-12-179	Otter Tail: Petition to include CSAPR related costs in FCA	Revenue Requirements	Lead Expert - MN Chamber
28	E017/M-12-708	Otter Tail: Renewable Resource Cost Recovery Factor	Cost Allocation and Rate Design	Lead Expert - MN Chamber
29	E002/M-10-1064	Xcel Energy: Transmission Cost Recovery Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
30	E002/M-10-1066	Xcel Energy: Renewable Energy Standard Cost Recovery Rider	Cost Allocation and Rate Design	Lead Expert - MN Chamber

	Docket Number	Type by State/FERC	Major Issues	Role
31	MPUC DOCKET NO. E002/M-11-278;MPUC DOCKET NO. E001/M-11-244;MPUC DOCKET NO. E015/M-11-241	Investor owned utilities CIP filings	Class Allocation and Rate Design	Lead Expert - MN Chamber
32	E, G-999/CI-08-133	Review of Financial Incentive Mechanism for CIP Programs	Avoided Costs, Policy Issues	Lead Expert - MN Chamber
33	E-999/CI-11-852	Renewable Energy Cost Impacts	Cost Effectiveness of Implementing Renewable Energy Standard	Lead Expert - MN Chamber
34	E017/RP-10-623	Otter Tail: Integrated Resource Plan	Resource Planning	Lead Expert - MN Chamber
35	E017/RP-10-623	Otter Tail: Hoot Lake Baseload Diversification Study	Resource Planning	Lead Expert - MN Chamber
36	E002/RP-10-825	Xcel Energy:Integrated Resource Plan	Resource Planning	Lead Expert - MN Chamber
37	E015/RP-13-53	Minnesota Power - Integrated Res. Plan	Resource Planning	Lead Expert - MN Large Industrial Group
38	E999/AA-12-757	Fuel Cost Recovery -All Utilities	Policy Issues	Lead Expert - MN Chamber
30	E017/M-14-201	OTP CIP Filing	Policy Issues	Lead Expert - MN Chamber
31	E017/RP-13-961	OTP IRP Filing	Resource Planning	Lead Expert - MN Chamber
32	ER002/GR-15-826	Xcel Energy Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - MN Chamber (Proceeding in progress)
33	ER17/GR-15-1033	Otter Tail Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - MN Chamber (Proceeding in progress)
34	E-999/CI-03-802	Fuel Cost Reform- All Utilities	Policy Issues	Technical Comments - MN Chamber
35	E002/M-16-777	Xcel Wind Portfolio	Revenue Requirement Issues	Technical Comments - MN Chamber
36	E, G999/CI-17-895	Tax Reform	Recommendations regarding TCJA related savings (in progress)	Technical Comments - MN Chamber
37	Docket No. E002/M-19-688	Xcel Energy Stay Out Proposal	Evaluating Staying Out of Rate Case	Technical Comments - MN Chamber
		Wisconsin		
38	05-ES-103	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
39	05-ES-104	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
40	05-ES-105	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
41	05-ES-106	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
42	05-ES-107	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
43	05-ES-108	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
44	05-ES-109	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
45	05-EI-141	Planning Reserve Margin Requirements	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
46	05-EI-148	Advanced Renewable Tariffs	Rates	Technical Comments on behalf of WIEG
47	05-UI-113	Cost allocation associated with Energy Efficiency Programs	Cost Allocation	Technical Comments on behalf of WIEG
48	05-UI-114	Innovative Ratemaking	Rate Design	Technical Comments on behalf of WIEG
49	05-UI-115	Quadrennial Planning Process - Energy Efficiency	Policy Issues	Technical Comments - On behalf of WIEG et al
50	05-UI-116	Demand Response and ARC Participation	Policy Issues	Technical Comments on behalf of WIEG
51	9300-EI-100	Impacts or Activities related to MISO	Policy Issues	Technical Comments on behalf of WIEG
52	05-EI-150	Review Potential Excess Capacity in WI	Policy Issues	Technical Comments - On behalf of WIEG et al
53	6680-GF-126	Wisconsin Power & Light:Experimental Economic Development Rider	Rate Design	Technical Comments on behalf of WIEG
54	6630-GF-134	We Energies: RTMP Rate	Rate Design	Technical Comments on behalf of WIEG
55	3270-UR-117	Madison gas & Electric: SP3 Rate Changes	Rate Design	Technical Comments on behalf of WIEG
56	6680-GF-130	Application of ED Rider by Mercury Marine	Rate Design	Technical Comments on behalf of WIEG
57	1-AC-234	Renewable Resource Credit Rule Revisions after 2009 Wisconsin Act 406	Policy Issues	Technical Comments - On behalf of WI Ind. Associations
58	05-EI-137	Class Cost of Service and Rate Design	Policy Issues	Technical Comments on behalf of WIEG
59	05-FE-100	Quadrennial Planning Process - Energy Efficiency	Policy Issues	Technical Comments - On behalf of WIEG/WPC/WMC
60	6630-BS-100	Presque Isle - WEPCO/Wolverine Transaction	Policy Issues	Technical Comments on behalf of WIEG
61	05-UR-107	WEPCO Base Rate Application	Revenue Requirement	Expert Witness - WIEG and CUB

	Docket Number	Type by State/FERC	Major Issues	Role
62	6680-UR-120	WP&L Base Rate Application	CCOSS, Rate Design and Revenue Allocation	Expert witness on behalf of WIEG
63	6630-FR-106	WEPCO 2017 Fuel Cost Plan	Recommendations for Revenues Related to Excess Capacity	Expert witness on behalf of WIEG
64	05-BS-212 and 05-AI-100	WEC transfer of assets to UMERC and related affiliated interest agreements	Protecting interests of WI customers served by WEC	Comments on behalf of WIEG, WPC and CUB
61	9400-YO-100	Wisconsin Gas Earnings Sharing Mechanism	Refund method	Technical comments of behalf of WIEG and CUB
62	05-AE-208	Affiliated Interest Agreement between WPSC and WEPCO - capacity only transaction	Recommendations for accounting treatment and capacity prices	Technical comments of behalf of WIEG, WPC and CUB
63	5-UR-108	Joint Application of WEPCO, Wisconsin Gas and WPSC for Approvals Related to Settlement Agreement	Revenue Requirement Issues	Expert witness on behalf of WIEG and CUB
64	05-AF-101	TCJA Investigation	Tax Impacts and Related Recommendations	Technical comments of behalf of WIEG, WPC and CUB
65	6680-UR-121	Alliant Rate Case	Revenue Requirements/Settlement Negotiations	Expert witness on behalf of WIEG
66	05-FE-101	Quadrennial Planning Process - Energy Efficiency	Recommendations regarding Cost Effectiveness and Other Aspect	Technical Comments on behalf of Several Wisconsin Industrial Associations
67	05-EF-102	Disbursement of ATC refunds	Policy/Alternatives of returning ATC refunds	Technical comments on behalf of WIEG and WPC
68	5820-UR-114	Superior Water Power and Light Rate Case	Cost of Service, Revenue Allocation and Rate Design	Expert witness on behalf of Enbridge Energy, LLC
69	05-UR-109	WEPCO Base Rate Case	Revenue Requirement/Settlement Negotiation, Cost of Service, R	Expert witness on behalf of CUB and WIEG on revenue requirement and WIEG for all else
70	6690-UR-126	WPSC Base Rate Case	Cost of Service, Revenue Allocation and Rate Design	Expert witness on behalf of WIEG
		Sasketchewan		
71	2008	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Expert Witness on behalf of ERCO
72	2010	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Expert witness on Behalf of ERCO and Assistance to SIECA
73	2013	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Technical Consultant to SIECA
		Iowa		
74	WRU-2014-0009-0150	Alliant Energy	Revenue Requirement	Expert Witness on behalf of Department of Justice - Office of Consumer Advocate
		Missouri		
75	ER-2014-0351	Empire District Electric Rate Case	FAC, Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
76	ER-2016-0023	Empire District Electric Rate Case	Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
	FERC Dockets			
77	ER07-1372	Integrating Ancillary Services into Energy Markets	Market Design and Policy Issues	Joint Protest; Midwest Industrial Customers
78	ER08-394	Resource Adequacy	Market Design and Policy Issues	Joint Protest; Midwest Industrial Customers
79	ER08-404	Schedule 30 - Emergency Demand Response	Compensation/Design/Policy	Joint Protest; Midwest Industrial Customers
80	RM07-19-0000 and AD07-7-0	Effective Competition in Wholesale Markets	Market Design and Policy Issues	Joint Protest; Wisconsin Industrial Energy Group
81	ER10-1791-000	Multi Value Projects - Transmission	Cost Allocation and Rate Design	Joint Protest; Wisconsin Industrial Energy Group
82	ER11-4337-000	MISO's Order 745 Compliance Filing	Cost Allocation and Other Policy Issues	Joint Protest; Wisconsin Industrial Energy Group
83	ER13-37-000 and ER13-38-00	System Support Resource	Cost Allocation and Other Policy Issues	Joint Protest;MN Industrial Group, Wisconsin Industrial Energy Group and Wisconsin Paper Council
84	RM10-23-000	Transmission Planning and Cost Allocation	Planning and Policy	Joint Protest; Wisconsin Industrial Energy Group
85	ER13-76,ER13-1962	System Support Resource	Cost Allocation and Other Policy Issues	Joint Protest;MN Industrial Group, Wisconsin Industrial Energy Group and Wisconsin Paper Council
86	ER14-1242-000 and ER14-24	System Support Resource	Cost Allocation and Other Policy Issues	Joint Comments - Wisconsin Industrial Energy Group and Citizens Utility Board
87	EL14-34-000	WI Commission Complaint regarding Cost Allocation associated with WEPCO's Presque Isle System Supply Resource	Cost Allocation	Joint Comments (Wisconsin Industrial Energy Group and Citizens Utility Board)
88	E:16-1-000	Petition for Waiver by Heartland Consumers Power District on behalf of itself and of its customers for waivers of Section 292.402 obligations	Primarily lack of standby power provisions	Comments developed in conjunctions with another consultant and Soybean Food Processors

Highlighted States Included For Investor Owned Utilities' Average Industrial Rate



Average Industrial Rates by Investor Owned Utility

No	Utility	State	Rate (Cents/kWh)
1	KCPL	Kansas	10.05
2	Indiana Michigan Power	Michigan	9.79
3	Northwestern Wisconsin Electric	Wisconsin	9.40
4	Duke Energy - Ohio	Ohio	9.04
5	Tucson Electric Power	Arizona	9.01
6	Montana Dakota Utilities	North Dakota	8.99
7	Montana Dakota Utilities	South Dakota	8.89
8	Indianapolis Power & Light	Indiana	8.88
9	Black Hills Power	Wyoming	8.61
10	Black Hills Power	Colorado	8.51
11	Empire	Kansas	8.45
12	Empire	Missouri	8.37
13	Arizona Public Service	Arizona	8.33
14	Madison Gas & Electric	Wisconsin	8.28
15	Black Hills Power	South Dakota	8.24
16	Westar - KPL	Kansas	8.16
17	Northern States Power	Minnesota	8.15
18	We Energies	Wisconsin	8.07
19	Consumers Energy	Michigan	7.91
20	Southern Indiana Gas & Electric	Indiana	7.91
21	KCPL	Missouri	7.85
22	Nevada Power	Nevada	7.85
23	American Electric Power - Columbus	Ohio	7.72
24	Wisconsin Power & Light	Wisconsin	7.68
25	American Electric Power - Ohio Power	Ohio	7.67
26	Northern States Power	Wisconsin	7.62
27	Empire	Oklahoma	7.61
28	Montana Dakota Utilities	Wyoming	7.59
29	Duke Energy - Kentucky	Kentucky	7.53
30	Interstate Power & Light	Iowa	7.52
31	CLECO Power	Louisiana	7.49
32	Duke Energy - Indiana	Indiana	7.49
33	Empire	Arkansas	7.45
34	Northern States Power	South Dakota	7.38
35	Northwestern Energy	Montana	7.29
36	Entergy New Orleans	Louisiana	7.21
37	Otter Tail Power	North Dakota	7.17
38	Northern Indiana Public Service	Indiana	7.16
39	Southwestern Electric Power	Louisiana	7.12
40	Northern States Power	North Dakota	7.11
41	AEP - Indiana Michigan	Indiana	7.04
42	Otter Tail Power	South Dakota	7.00
43	Montana Dakota Utilities	Montana	7.00
44	Unisource Electric	Arizona	6.93
45	Northwestern Energy	South Dakota	6.92
46	Black Hills Power	Montana	6.90

Average Industrial Rates by Investor Owned Utility

No	Utility	State	Rate (Cents/kWh)
47	Ohio Edison	Ohio	6.88
48	Commonwealth Edison	Illinois	6.88
49	PacifiCorp	Idaho	6.87
50	El Paso Electric	Texas	6.86
51	El Paso Electric	New Mexico	6.84
52	Mississippi Power	Mississippi	6.82
53	Louisville Gas & Electric	Kentucky	6.69
54	Westar - KGE	Kansas	6.68
55	Toledo Edison	Ohio	6.67
56	GMO	Missouri	6.64
57	Minnesota Power Company	Minnesota	6.59
58	Otter Tail Power	Minnesota	6.59
59	Entergy Mississippi	Mississippi	6.55
60	DTE Electric	Michigan	6.55
61	American Electric Power	Kentucky	6.50
62	Cheyenne Light, Fuel & Power	Wyoming	6.38
63	Dayton Power & Light	Ohio	6.37
64	Ameren	Missouri	6.36
65	Southwestern Electric Power	Texas	6.31
66	Public Service Company of Colorado	Colorado	6.30
67	Superior Water, Light & Power	Wisconsin	6.30
68	Northern States Power	Michigan	6.29
69	Alabama Power	Alabama	6.17
70	PacifiCorp	Wyoming	6.15
71	American Electric Power	Tennessee	6.12
72	Kentucky Utilities	Kentucky	5.96
73	Southwestern Electric Power	Arkansas	5.92
74	PacifiCorp	Utah	5.91
75	Wisconsin Public Service	Wisconsin	5.83
76	Entergy Arkansas	Arkansas	5.80
77	Upper Michigan - Wisconsin Public Service	Michigan	5.72
78	MidAmerican	Iowa	5.67
79	Upper Michigan - We Energies	Michigan	5.51
80	Public Service Company of New Mexico	New Mexico	5.49
81	Idaho Power	Idaho	5.45
82	MidAmerican	Illinois	5.35
83	Sierra Pacific	Nevada	5.24
84	Avista	Idaho	5.17
85	Upper Peninsula	Michigan	5.11
86	Entergy Gulf States	Louisiana	5.08
87	Southwestern Public Service	New Mexico	5.01
88	OG&E Electric	Arkansas	5.00
89	Public Service Company of Oklahoma	Oklahoma	4.95
90	Entergy Louisiana	Louisiana	4.89
91	MidAmerican	South Dakota	4.85
92	Entergy Texas	Texas	4.76
93	OG&E Electric	Oklahoma	4.73
94	Cleveland Electric Illuminating	Ohio	4.30
95	Southwestern Public Service	Texas	4.16

A&E 6NCP Production Allocator Excluding Interruptible Load

Column	1	2	3	4	5	6	7
	Peak Demand	**Energy Sales**	**Average**	**Excess**	**Average**	**Excess**	**Total**
	6 NCP	**with Losses**	**Demand**	**Demand**	**Demand**	**Demand**	**Allocator**
Rate Class	**(KW)**	**(kWh)**	**(KW)**	**(KW)**	**(%)**	**(%)**	**(%)**
RG-Residential	555,082	1,795,766,369	204,996	350,086	40.56%	58.82%	50.31%
CB-Commercial	87,696	340,118,907	38,826	48,869	7.68%	8.21%	7.96%
SH-Small Heating	23,644	91,300,331	10,422	13,222	2.06%	2.22%	2.15%
GP-General Power	187,848	923,531,065	105,426	82,422	20.86%	13.85%	17.11%
SC-P PRAXAIR Transmission	826	5,339,586	610	216	0.12%	0.04%	0.08%
TEB-Total Electric Bldg	83,690	384,856,858	43,933	39,756	8.69%	6.68%	7.62%
PFM-Feed Mill/Grain Elev	200	451,386	52	149	0.01%	0.03%	0.02%
LP-Large Power	149,874	847,092,535	96,700	53,174	19.13%	8.93%	13.68%
MS-Miscellaneous	18	149,208	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,805	24,077,589	2,749	3,056	0.54%	0.51%	0.53%
PL-Private Lighting	4,667	13,882,074	1,585	3,082	0.31%	0.52%	0.42%
LS-Special Lighting	1,277	825,400	94	1,182	0.02%	0.20%	0.11%
Total	1,100,626	4,427,391,308	505,410	595,216	100.00%	100.00%	100.00%

Load Factor	46.57%
1 - Load Factor	53.43%
Average Demand	505,410
	1,085,224

Note: Interruptible load as specified in response to MECG 2.3 was removed from GP and SC-P classes.

Derivation of Firmed Up Present Revenues

Column	1	2	3	4
	Present Base Revenues ($)	Interruptible Credits ($)	Recovery of Interruptible Credits ($)	Firmed Up Present Base Revenues ($)
RG-Residential	214,578,480		(190,116)	214,388,364
CB-Commercial	43,172,528		(30,094)	43,142,434
SH-Small Heating	9,894,348		(8,113)	9,886,235
GP-General Power	84,229,832	12,144	(64,663)	84,177,314
SC-P PRAXAIR Transmission	4,049,334	365,712	(286)	4,414,761
TEB-Total Electric Bldg	36,067,139		(28,781)	36,038,358
PFM-Feed Mill/Grain Elev	71,595		(68)	71,527
LP-Large Power	61,612,711		(51,704)	61,561,007
MS-Miscellaneous	14,471		(6)	14,465
SPL-Municipal St Lighting	2,185,762		(1,994)	2,183,769
PL-Private Lighting	4,064,689		(1,597)	4,063,092
LS-Special Lighting	131,578		(434)	131,145
Total Company	460,072,468	377,856	(377,856)	460,072,468

Note: Present Base Revenues adjusted for TCJA (Column 1) from COSS model in response to MECG 2.2 (Target Revenues tab – Row 13)

SCHEDULE KM-4

MECG COSS Results Summary at Present Rates (1)

Empire District Electric (MISSOURI)	Total Company	Res Gen RG	Comm CB	Small Heating SH	Prax SC-P	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Lts MS	Street Lts SPL	Private Lts PL	Spec Lts LS
Rate Base	1,457,360,469	788,605,880	124,879,088	30,454,706	7,922,758	96,918,943	220,377	164,854,063	29,882	19,173,329	6,655,900	1,773,555
Current Base Rate Revenues (Adj for TCJA)	460,072,468	214,578,480	43,172,528	9,894,348	4,415,046	36,067,139	71,595	61,612,711	14,471	2,185,762	4,064,689	131,578
Operating Revenues	538,145,269	245,076,376	49,109,480	11,449,205	5,548,908	42,505,741	79,799	76,789,640	16,870	3,510,334	4,355,210	146,079
Operating Expenses												
O&M Expenses	334,960,616	167,565,430	27,820,902	6,801,283	3,605,107	23,152,057	37,173	48,239,779	16,389	1,852,288	1,208,023	177,864
Depreciation & Amortization	82,298,434	47,183,621	7,428,155	1,717,276	359,562	4,845,232	11,781	7,942,627	2,015	1,179,654	708,532	124,239
Taxes Other than Income	27,922,821	15,893,858	2,494,097	583,216	129,175	1,681,798	3,961	2,805,340	898	304,037	237,835	40,738
Gains / Losses	-	-	-	-	-	-	-	-	-	-	-	-
Interest on Customer Deposits	863,681	715,176	109,145	18,288	-	6,710	76	-	16	-	-	667
Total Operating Income	92,099,716	13,718,292	11,257,181	2,329,143	1,455,065	12,819,945	26,807	17,801,894	(2,448)	174,355	2,200,820	(197,430)
Less:												
Interest Expense	33,957,956	18,375,306	2,909,808	709,625	184,608	2,258,308	5,135	3,841,265	696	446,758	155,089	41,326
Net Income Before Taxes	58,141,760	(4,657,014)	8,347,373	1,619,518	1,270,457	10,561,636	21,672	13,960,629	(3,145)	(272,402)	2,045,731	(238,755)
Total Income Tax	13,861,070	(1,110,238)	1,990,024	386,095	302,877	2,517,908	5,167	3,328,232	(750)	(64,941)	487,705	(56,920)
Excess ADIT Amortization & ITC	(10,804,220)	(5,846,372)	(925,798)	(225,778)	(58,736)	(718,514)	(1,634)	(1,222,154)	(222)	(142,143)	(49,344)	(13,148)
Net Income after Taxes	89,042,866	20,674,902	10,192,954	2,168,826	1,210,924	11,020,551	23,274	15,695,816	(1,477)	381,439	1,762,459	(127,362)
Earned ROR	6.11%	2.62%	8.16%	7.12%	15.28%	11.37%	10.56%	9.52%	-4.94%	1.99%	26.48%	-7.18%

(1) MECG used the COSS model provided in response to MECG 2.2 to make its adjustments as described in testimony. The model, including the data, allocators and costs are all the same as provided in the Company's Workpapers. Unlike the original COSS, however, the calculation of the proposed $26.5 million deficiency compared to current base rate revenues is shown more clearly. The summary of MECG results are from Alloc – Income taxes tab and current base revenues are from Revenue Target tab (Row 13). See Kavita Maini Workpapers, MECG DR 2.2 EDE MO COSS Model (Excel spreadsheet)