Exhibit No.:	
Issue:	*Rate Design*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
Case No.:	*ER-2019-0374*
Date Testimony Prepared:	*March 9, 2020*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2019-0374

Jefferson City, Missouri
March 2020

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Q. Please state your name and business address.

A. My name is Sarah L.K. Lange and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. Who is your employer and what is your present position?

A. I am employed by the Missouri Public Service Commission ("Commission") and my title is Regulatory Economist III, Tariff/Rate Design Department of the Industry Analysis Division. A copy of my credentials is attached to the Staff's Class Cost of Service Report ("CCOS Report") filed on January 29, 2020, in this matter, to which I contributed.

Q. What is the purpose of your rebuttal testimony?

A. I will:

1) Correct errors at pages 20 and 23 of the CCOS Report
2) Respond to use of the word "demand," in rate design testimonies of Empire's witness Lyons and MECG's witness Maini and clarify the various types of demand that are relevant to this case;
3) Respond to Ms. Maini's presentation of EEI average bill data and provide accurate bill histories for various customer usage profiles;
4) Provide the results of Staff's CCOS using company-supplied hourly loads for Praxair and the PFM rate schedule in place of imputed non-customer specific loads, including the costs of energy to serve load, in response to MECG's proposed rate design.
5) Discuss the relationship of the proposed rate designs for the LP rate schedule to the cost of the energy to serve that load in response to MECG's proposed rate design,
6) Address the reliability of the CCOS studies in this case as it relates to the inaccuracy of Empire's sales data as discussed by Robin Kliethermes in her CCOS Rebuttal, and the insufficiency of Empire's data for weather normalization as discussed by Michael L. Stahlman in his COS Rebuttal.

Q. What are your corrections at pages 20 and 23 of the CCOS Report?

A. On page 20 of the CCOS Report I included a typographical misstatement of the Empire-requested LP non-summer demand charge. Also, due to a transcription error in the billing determinants in my underlying spreadsheet, the table of Staff's approximate rates for the LP rate schedule in the CCOS Report is not a reasonable approximation of the implementation of Staff's recommended rate design for the LP rate schedule. Corrected tables of both items are provided below:

LP	Current		Current Effective		Requested YE-2020-0029	
Temp. Tax Reduction	$	0.00298				
Customer Charge	$	283.55	$	283.55	$	325.00
Summer Demand	$	15.69	$	15.69	$	15.69
Winter Demand	$	8.66	$	8.66	$	8.66
Facilities Demand	$	1.88	$	1.88	$	2.86
Summer 1st 350 HU	$	0.06809	$	0.06511	$	0.06809
Summer Add. HU	$	0.03683	$	0.03385	$	0.03683
Winter 1st 350 HU	$	0.06048	$	0.05750	$	0.06048
Winter Add. HU	$	0.03552	$	0.03254	$	0.03550
EECR	$	0.00071	$	0.00071	$	0.00071

LP	Staff Rate Design	
Customer Charge	$	235.53
Summer Demand	$	13.03
Winter Demand	$	7.19
Facilities Demand	$	1.56
Summer 1st 350 HU	$	0.06161
Summer Add. HU	$	0.03565
Winter 1st 350 HU	$	0.05529
Winter Add. HU	$	0.03456

At page 23 I referred to the result of dividing the cost of energy obtained at transmission voltage to serve each class as "Average price per kWh @ customer meter." A better label would be "Average cost of transmission-voltage energy per metered kWh." The corrected and expanded table is provided below for reference:

	Residential	CB/SH	GP/TEB	Large Power	Feed & Grain	Contract Transmission	Lighting	System Average
Average price per kWh @ transmisison voltage:	$ 0.0323	$ 0.0319	$ 0.0311	$ 0.0300	$ 0.0312	$ 0.0293	$ 0.0275	$ 0.0314
Average cost of transmission-voltage energy per metered kWh:	$ 0.0310	$ 0.0307	$ 0.0301	$ 0.0293	$ 0.0300	$ 0.0293	$ 0.0264	$ 0.0303
Average loss-adjusted price per kWh:	$ 0.0342	$ 0.0338	$ 0.0330	$ 0.0312	$ 0.0330	$ 0.0293	$ 0.0291	

<u>“DEMAND” TYPES AND THEIR APPROPRIATE USES IN REVENUE RECOVERY</u>

Q. At page 36 of his testimony Mr. Lyons states that moving LP revenue recovery as a percent to demand charges better reflects “demand-related costs,” and on page 12 of MECG’s witness Maini’s direct she states that:

> . . . 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.

Are these characterizations of the relationship between generation capacity costs and Empire’s demand charge accurate?

A. No, both conflate a customer’s monthly Non-Coincident Demand with the system’s annual Coincident demand. Even within the context of rate design and class cost of service, the word “demand” has several different meanings. At its most basic, “demand” is simply consumption at a given point in time. In a familiar water analogy, the height of the water in a pipe in an instant is the demand, and the water that drains into the bucket is the energy. In that situation, the higher the water level in the pipe in an instant, the higher the demand. However, as used in energy regulation, “demand” always has a time component. For example, a customer’s energy consumption during a specified 15 minute interval or during a specified one hour interval are the most common meanings of demand. In discussing demand one must always be cognizant of the type of demand (coincident or non-coincident), the level of demand (for example, a single customer, a class of customers, an entire utility company, etc.), the frequency of demand (for example, daily, monthly, annual), and the duration of demand (for example, 15 minutes or 1 hour).

1. Customer Non-Coincident Peak Demand, or "NCP Demand," is the 15 minute interval during which a particular customer used the most energy during a month or year. Customer NCP Demand may be based on the annual peak usage or monthly peak usage. This is the demand that is measured by a customer's "Demand meter" and is the demand that is subject to Empire's "demand charge." On the LPS rate schedule, the "facilities demand" is the customer's annual "NCP Demand," and the "billing demand" is the customer's NCP in the applicable billing month.

2. Class NCP Demand, is the one hour interval during each month in which a studied rate class comprised of one or more rate schedules used the most energy in the relevant month. Generally, consolidating more than one rate schedule into a studied class will produce a lower total NCP Demand for the consolidated classes than measuring each rate schedule separately and adding them together.

3. Class Coincident Peak Demand is the usage of each studied rate class during the hour at which the system recorded the highest usage during a month or year.

4. System Peak Demand is either the highest energy usage the system experienced during an hour of the year, or the system's load at the time that the relevant RTO experienced its highest energy usage during an hour of the year.

5. Customer Coincident Peak Demand is an emerging billing determinant reflecting the maximum usage of a customer during a specified interval within a specified

period, in which the specified period encompasses conditions that are associated with system peaks ranging from the local distribution system to the RTO system.

Q. How may a utility utilize each type of demand and how may each type of demand directly cause the costs incurred by a utility or influence the costs allocated within a CCOS study?

A.

1. Customer Non-Coincident Peak Demand, or "NCP Demand," (the 15 minute interval during a month or year during which a particular customer used the most energy) is a direct billing determinant for the LP, GP, TEB, Contract Transmission, and Special Contract-Praxair rate schedules. It is an indirect billing determinant for calculating the "hours use" energy blocks for customers served on the LGS and SPS rate schedules.[1]

Customer NCP Demand causes the utility to make long-term decisions concerning the size of the distribution system including and between that customer's meter and the first substation.[2] These decisions carry over to future customers. For example, if a welding shop were to be built on a vacant lot, Empire would install a different (and more expensive) meter than if a house were being built there. The costs associated with the necessary upgrades would be borne by the customer requesting service to the extent that the net revenues that customer is expected to produce do not cover the costs. If the welding shop closes and a small insurance office moves in, it is very unlikely that Empire would replace the lines, transformers, meters, and service drops with smaller infrastructure, unless distribution work happened to be

[1] "CB/SH" – Commercial Service and Small Heating Service; "GP/TEB" - General Power Service and Total Electric Building Service; "LPS" - Large Power Service; "Feed & Grain" – Feed Mill and Grain Elevator Service, Schedule PFM; Contract Transmission - Special Transmission Service.

[2] A large customer's NCP demand may have impacts beyond the first substation.

occurring in the area and the items were in need of repair (or Empire made an economic decision to replace them related to their level of net investment).

The costs that are reasonably related to customers' NCP Demand are those costs that are related to the demands the customer will exert on the local distribution system. These costs vary very little over the course of a typical year, with two exceptions. First, if a customer increases demand such that additional infrastructure is required, the Empire tariff outlines the allowances and contributions related to payments the customer will be required to make to address the costs of the infrastructure. Second, if Empire replaces infrastructure in an area, it may increase or decrease the capabilities of the system related to existing, changed, or anticipated customer NCP demands.

2. Class NCP Demand, (the one hour interval during each month during which a studied rate class comprised of one or more rate schedule(s) used the most energy in the relevant month) is a metric used in some Class Cost of Service Studies for allocating production capacity costs, transmission capacity costs, and distribution system costs. To the extent it is used for the allocation of production capacity costs, it is also relevant to the revenues obtained from the operation of generating facilities. It is not a direct billing determinant for any customer, and the costs that it is associated with do not vary within the year based on the level of NCP demand exerted by any class or rate schedule.

3. Class Coincident Peak Demand (the usage of each studied rate class during the hour at which the system recorded the highest usage during a month or year) is a metric used in some Class Cost of Service Studies for allocating production capacity costs, transmission capacity costs, and distribution system costs. To the extent it is used for the allocation of production capacity costs, it is also relevant to the revenues obtained from the

operation of generating facilities. It is not a direct billing determinant for any customer, and the costs that it is associated with do not vary within the year based on the level of demand coincident with peak exerted by any class or rate schedule. (The sum of the class loads is discussed as "System Peak Demand".)

4. System Peak Demand (typically the highest energy usage the system experienced during an hour of the year, or the system's load at the time that the relevant RTO experienced its highest energy usage during an hour of the year) relates to the level of capacity Empire is obligated to have available through ownership or contract for FERC, NERC, SERC, SPP, and Commission planning purposes. It is not a determinant for any particular class.

5. Customer Coincident Peak Demand (the maximum usage of a customer during a specified interval within a specified period, where the specified period encompasses conditions that are associated with system peaks ranging from the local distribution system to the RTO system) is not currently a billing determinant in use for any Missouri utility, although a variation of this determinant is under consideration for limited use in the pending Ameren Missouri rate case, Case No. ER-2019-0335. Ideally, this metric would be useful for allocation to the classes and recovery from customers of those costs that do vary with either local system conditions or RTO requirements and pricing. For example, if Empire experienced a need to increase the size of distribution system transformers due to heavy usage occurring on summer afternoons, a reasonable recovery for that cost would be the highest hour of use a customer exerts on a system on ANY summer afternoon. Similarly, a reasonable recovery (as a billing determinant) or allocation (for CCOS) for capacity costs may be the highest hour of use a customer exerts on the system on ANY Summer afternoon (for the billing determinant)

allocated for CCOS purposes on the sum of the highest hour of use all customers exerted on the system on ANY summer afternoon (for the allocation).

The rationale is twofold. First, the hour that the summer peak occurred will be unknown until after the summer is over. Second, the NCP demands of customers are largely independent variables. While cumulative air conditioning load appears to be the largest driver of summer peak loads, the independent choices of homes and businesses to consume electricity during times of extreme heat reduce the diversity typically associated with customer NCP demands. Meaning, the decision of a final cumulative customer to switch on a lightbulb in a dim warehouse on a summer afternoon may be what distinguishes the hour of system peak from just another high-consumption hour. Only a subset of HVAC load will be present in that hour. It would not be reasonable to punitively bill those customers who happened to be running HVAC equipment in that hour when the lightbulb was on versus identical conditions the day prior.

Q. How is each demand determined?

A. Customer Non-Coincident Peak Demand is a determinant retained by the company's billing system for customers on the currently-structured LP, GP, TEB, Contract Transmission, and Special Contract-Praxair rate schedules. Limited data is available for customers served on other classes.

Class Non-Coincident Peak Demand, Class Coincident Peak Demand, and System Peak Demand are all developed as weather-normalized metrics from load research data.

Q. What is the relevance of a customer's NCP demand to the cost of Empire's generation capacity whether owned or contractual?

A. A customer's NCP demand is not relevant to Empire's capacity requirements. The usage of a customer in the interval associated with the system peak is the determinant relevant to Empire's capacity requirements. There may have been a time where customer usage was so uniform that it could reasonably be assumed that a customer's NCP demand would coincide with system peak, but that is certainly not the case today. Therefore, it is no more reasonable to recover the costs associated with system peak demands via a customer's NCP demand than it is to recover those costs via a customer's energy consumption, and it is potentially less reasonable to do so.

Q. Ms. Maini's statement implied that lower NCP demand charges on the LP rate schedule would drive a need for additional generation investments,[3] is this a reasonable contention?

A. No. A customer's NCP demand is not relevant to Empire's capacity requirements, but also, Empire has represented that its recent decisions to increase its capacity have been related to environmental compliance requirements and energy market opportunities. Further, Empire's ongoing acquisitions of wind capacity are poorly suited to meeting coincident peak customer demand.

Q. How has the Regulatory Assistance Project addressed the use of NCP demand charges for recovery of production and transmission costs?

A. The RAP publication, "Smart Rate Design for a Smart Future," authored by Jim Lazar and Wilson Gonzalez includes the following:

> It is generally agreed that demand or capacity-related costs, to the extent they occur on a system, are primarily associated with the system peak demand, not the individual customer peak demand. Only very local

[3] See Maini Direct at page 12 "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."

components of the distribution system (service drop, line transformer) are sized to the individual customer load.

Because traditional demand charges are measured on the basis of the individual customer's peak, regardless of whether it coincides with the peaks on any portion of the system, this approach results in a mismatch between the system coincident peak costs used to set prices and the actual costs incurred at the time of the customer's noncoincident peak. While the revenue to be collected is represented by the system coincident peak costs, the billing units used to set the prices are the sum of all customers' individual non-coincident peaks. This results in a lower demand charge for everyone, but has the effect of requiring customers who are not contributing proportionately to the system peak to bear a greater share, while those who are contributing to the system peak bear a lesser share of revenue responsibility than would occur if demand charges were based on usage during the system coincident peak. A demand "ratchet" is a rate element that requires a customer to pay a demand charge in every month that is based on their highest usage during the year, often based on summer peak demand. These provide stable revenues to utilities, but discourage energy efficiency throughout the year, since a significant part of the cost of service is fixed and the savings from peak load reduction from energy efficiency are not realized until the ratchet period has been completed. This also has the effect of aggravating the mismatch.[4]

Demand charges were implemented for commercial and industrial customers in an era where sophisticated TOU metering was prohibitively expensive. Today, with smart meters and AMI, these costs are trivial. Although demand charges once served the useful function of providing a simple price signal to customers that their peak usage caused long-term costs for capacity to be incurred to meet peak demand even when those resources lay idle most of the time, they may not be appropriate in the presence of current market conditions, smart technologies, and other regulatory policies. Progress with demand response and the development of robust wholesale energy markets allows utilities to meet short-term peak needs with short-term resources, obviating the need for demand charges. Given these conditions, it is more appropriate to utilize more temporally granular time-differentiated rates, in lieu of demand charges. **AMI provides an opportunity to move away from the rather crude allocation of cost responsibility afforded by demand charges, and toward a cost recovery framework that is more focused on the costs that utilities and society incur to meet the daily and hourly needs of the system.**[5] [Emphasis added.]

[4] Pages 37 - 38.
[5] Page 50 - 51.

Q. Could you provide an illustration of this mismatch?

A. Yes. For simplicity, consider a hypothetical utility with only two classes, a General Service Class and a Residential Class, and a production capacity revenue requirement of $10 million. The characteristics of the General Service customers – as individuals – and the Residential Class are provided below:

			Demand During Summer Peaks	NCP Demand*	Energy Consumption
General Service Class	Customer A	Nighttime Usage, Year Round	10	100	437,835
	Customer B	Daytime Usage, Year Round	100	100	433,500
	Customer C	Daytime Usage, Summer Only	100	100	144,500
Residential Class			1,000	1,200	4,380,000
		*Sum of NCP demands of all Residential Customers			

A CCOS would result in allocation of approximately 17% of production capacity costs ($1.7 million) to the General Service Class, and 83% ($8.3 million) to the Residential Class.

If the General Service class's rates are designed to recover the General Service class's allocation of production capacity costs from the NCP demand charge (or from the first blocks of an Hour's Use energy charge) the resulting allocation of production capacity costs per GS customer is provided below:

		Demand During Summer Peaks	NCP Demand*	Energy Consumption	Class Allocation of Capacity Costs		General Service Intra-Class Allocation of Capacity Costs	
Customer A	Nighttime Usage, Year Round	10	100	437,835			33%	$ 578,512
Customer B	Daytime Usage, Year Round	100	100	433,500	17%	$ 1,735,537	33%	$ 578,512
Customer C	Daytime Usage, Summer Only	100	100	144,500			33%	$ 578,512

This design causes each customer to provide revenues to cover production capacity costs on the basis of that customer's NCP, even though Customer A contributes much less than Customer B or Customer C to the need for production capacity. However, if the Demand During Summer Peaks is used to allocate the costs directly to the customers, as shown in the table below, Customer A contributes proportionately to Customer A's contribution to the need for capacity costs, and Customers B & C contribute additional revenues to cover their contribution to the need for capacity costs. Notice that the Residential class's responsibility remains the same.

			Demand During Summer Peaks	NCP Demand*	Energy Consumption	Class Allocation of Capacity Costs		Reasonable and Equitable Allocation of Capacity Costs	
General Service Class	Customer A	Nighttime Usage, Year Round	10	100	437,835	17%	$ 1,735,537	1%	$ 82,645
	Customer B	Daytime Usage, Year Round	100	100	433,500			8%	$ 826,446
	Customer C	Daytime Usage, Summer Only	100	100	144,500			8%	$ 826,446
Residential Class			1,000	1,200	4,380,000	83%	$ 8,264,463	83%	$ 8,264,463

Q. Even if customers' NCP's were coincident with class CP and system CP, is it problematic to overallocate revenue recovery to demand charges?

A. Yes. Even if a low load factor customer peaks coincident with its class peak, if revenue recovery is overallocated to demand charges, then that customer leaving the class would take with them a bigger percent of class revenues than the level of allocated demand that they are eliminating.

Q. What is the significance of this rate case as it relates to this example and the quoted excerpt emphasized above?

A. Empire is beginning deployment of AMI meters and customer infrastructures. Once properly deployed, Staff is optimistic that Empire's rate structures will move toward that described in the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245, concerning residential and utility-wide rate design. A well-designed rate structure for customers currently served on the LP rate schedule would likely include time-variant energy charges and a coincident-peak demand charge for recovery of revenue, except that related to customer-specific expenses and installations.

CUSTOMER BILL HISTORIES

Q. At page 9 Maini discusses EEI Typical Bills and Average Rate Report data from Summer 2019, and asserts that Empire's industrial rates have declined in competiveness since those in place in 2015. Does discussion of an "average rate" provide an accurate summary of the bills experienced by GP and LPS customers over time?

A. Unfortunately, discussion and comparison of multipart rates is complicated, and simple comparisons fail to account for the changing customer base (1) due to changes in customer characteristics and (2) due to changes in the total numbers of customers receiving service whether due to rate switching or due to customer growth/loss. While no metric is perfect, it is probably most useful to review the bills or average $/kWh that would be experienced by a given customer with that customer's characteristics held constant over time. Given the size of Empire's customer base and classes, it is impossible to accurately summarize these impacts for all potential customers. Further, it is possible that a customer experiencing the real-time effects of changes in rate design would change rate schedules one or more times.

To facilitate these comparisons, Staff created a set of Customer Profiles, and priced out the bills for those customers from the final rates promulgated from each rate case since Case No. ER-02-424. For example, the experienced average dollar per kWh for each of the studied Residential Profiles are provided below:

	12/1/2002	3/27/2005	12/14/2007	8/23/2008	9/10/2010	6/15/2011	4/1/2013	7/26/2015	9/14/2016	Net Tax	Empire Proposed	Staff
1,500 ft Home w/ Space Heat	$ 0.0697	$ 0.0772	$ 0.0873	$ 0.0931	$ 0.1055	$ 0.1100	$ 0.1176	$ 0.1249	$ 0.1323	$ 0.1272	$ 0.1353	$ 0.1272
Large Home AC only	$ 0.0694	$ 0.0766	$ 0.0868	$ 0.0926	$ 0.1049	$ 0.1092	$ 0.1169	$ 0.1242	$ 0.1316	$ 0.1264	$ 0.1339	$ 0.1264
Small Apt w/ Space Heat	$ 0.0749	$ 0.0825	$ 0.0930	$ 0.0992	$ 0.1124	$ 0.1152	$ 0.1230	$ 0.1305	$ 0.1382	$ 0.1330	$ 0.1422	$ 0.1330

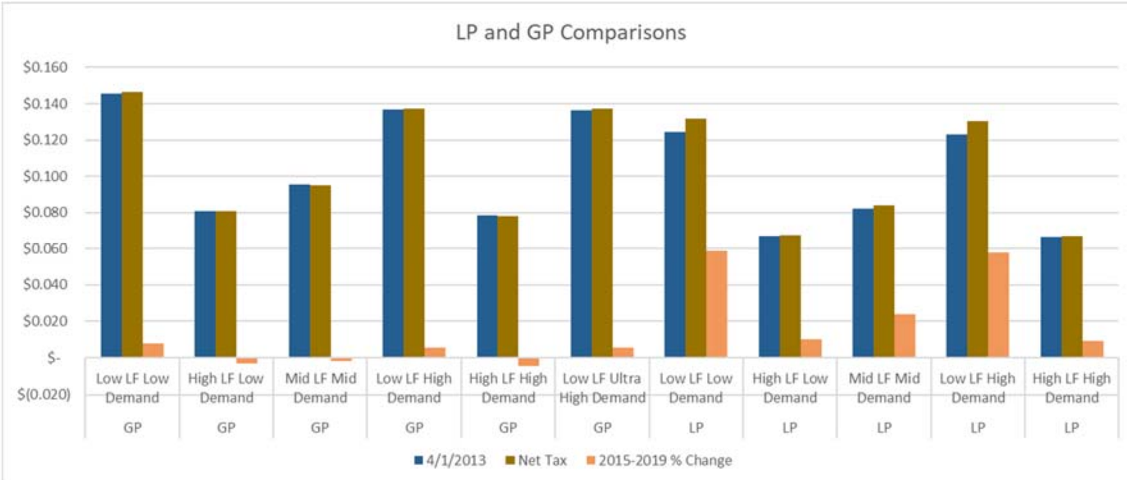
To facilitate comparisons across customers of very different sizes, Staff divided the total bills described above by the kWh of each customer. This produced an experienced average $/kWh that can be displayed on a graph with a readable scale when comparing the bill one may experience with a small apartment to the bill one may experience when participating in substantial industrial manufacturing.

The experienced average $/kWh by Customer Profile is provided below, with customer profiles that have experienced a decrease in average experienced dollar per kWh since 2015 indicated in red highlighting:

		12/1/2002	3/27/2005	12/14/2007	8/23/2008	9/10/2010	6/15/2011	4/1/2013	7/26/2015	9/14/2016	Net Tax	Empire Proposed	Staff	**2015-2019 % Change**
Res.	1,500 ft Home w/ Space Heat	$ 0.070	$ 0.077	$ 0.087	$ 0.093	$ 0.105	$ 0.110	$ 0.118	$ 0.125	$ 0.132	$ 0.127	$ 0.135	$ 0.127	8.12%
Res.	Large Home AC only	$ 0.069	$ 0.077	$ 0.087	$ 0.093	$ 0.105	$ 0.109	$ 0.117	$ 0.124	$ 0.132	$ 0.126	$ 0.134	$ 0.126	8.17%
Res.	Small Apt w/ Space Heat	$ 0.075	$ 0.083	$ 0.093	$ 0.099	$ 0.112	$ 0.115	$ 0.123	$ 0.130	$ 0.138	$ 0.133	$ 0.142	$ 0.133	8.12%
CB	Flat	$ 0.078	$ 0.085	$ 0.096	$ 0.102	$ 0.116	$ 0.121	$ 0.129	$ 0.133	$ 0.138	$ 0.133	$ 0.141	$ 0.120	2.89%
CB	24 Hour Retail	$ 0.068	$ 0.075	$ 0.085	$ 0.091	$ 0.103	$ 0.110	$ 0.118	$ 0.122	$ 0.126	$ 0.121	$ 0.127	$ 0.109	2.55%
CB	Small Office/Service	$ 0.083	$ 0.089	$ 0.100	$ 0.107	$ 0.121	$ 0.125	$ 0.134	$ 0.138	$ 0.143	$ 0.138	$ 0.146	$ 0.123	3.01%
GP	Low LF Low Demand	$ 0.087	$ 0.097	$ 0.109	$ 0.114	$ 0.129	$ 0.136	$ 0.145	$ 0.148	$ 0.151	$ 0.146	$ 0.152	$ 0.132	0.76%
GP	High LF Low Demand	$ 0.047	$ 0.052	$ 0.060	$ 0.063	$ 0.072	$ 0.076	$ 0.081	$ 0.082	$ 0.084	$ 0.081	$ 0.085	$ 0.076	-0.34%
GP	Mid LF Mid Demand	$ 0.056	$ 0.062	$ 0.071	$ 0.075	$ 0.085	$ 0.089	$ 0.095	$ 0.097	$ 0.099	$ 0.095	$ 0.099	$ 0.089	-0.16%
GP	Low LF High Demand	$ 0.082	$ 0.090	$ 0.103	$ 0.107	$ 0.122	$ 0.128	$ 0.137	$ 0.139	$ 0.142	$ 0.137	$ 0.142	$ 0.124	0.57%
GP	High LF High Demand	$ 0.046	$ 0.051	$ 0.058	$ 0.061	$ 0.070	$ 0.073	$ 0.079	$ 0.080	$ 0.082	$ 0.078	$ 0.082	$ 0.074	-0.46%
GP	Low LF Ultra High Demand	$ 0.081	$ 0.090	$ 0.102	$ 0.107	$ 0.121	$ 0.128	$ 0.136	$ 0.139	$ 0.142	$ 0.137	$ 0.142	$ 0.124	0.56%
LP	Low LF Low Demand	$ 0.073	$ 0.082	$ 0.092	$ 0.098	$ 0.111	$ 0.116	$ 0.124	$ 0.126	$ 0.135	$ 0.132	$ 0.140	$ 0.117	5.86%
LP	High LF Low Demand	$ 0.038	$ 0.043	$ 0.049	$ 0.053	$ 0.060	$ 0.062	$ 0.067	$ 0.068	$ 0.070	$ 0.067	$ 0.072	$ 0.064	0.99%
LP	Mid LF Mid Demand	$ 0.048	$ 0.053	$ 0.061	$ 0.065	$ 0.073	$ 0.077	$ 0.082	$ 0.083	$ 0.087	$ 0.084	$ 0.089	$ 0.077	2.38%
LP	Low LF High Demand	$ 0.072	$ 0.081	$ 0.091	$ 0.097	$ 0.110	$ 0.115	$ 0.123	$ 0.125	$ 0.133	$ 0.130	$ 0.139	$ 0.116	5.79%
LP	High LF High Demand	$ 0.038	$ 0.043	$ 0.049	$ 0.052	$ 0.059	$ 0.062	$ 0.067	$ 0.068	$ 0.070	$ 0.067	$ 0.072	$ 0.063	0.93%
		$ 0.065	$ 0.072	$ 0.082	$ 0.087	$ 0.099	$ 0.103	$ 0.110	$ 0.113	$ 0.118	$ 0.114	$ 0.120	$ 0.106	3.17%

Q. What type of customers have received above-average increases since the rates took effect in 2015?

A. Lower load factor customers on the GP and LP rate schedules – such as factories that operate a single shift – have seen the largest increases outside of the residential class. CB customers, regardless of commercial or industrial classification have also seen large increases. A more detailed comparison of the customer profiles for the LP and GP rate schedules are provided below, as is a simple average summary of the above table.



	2015-2019 % Change
High load factor average:	0.28%
Mid load factor average:	1.11%
Low load factor average:	2.71%
CB & Res. average:	5.48%

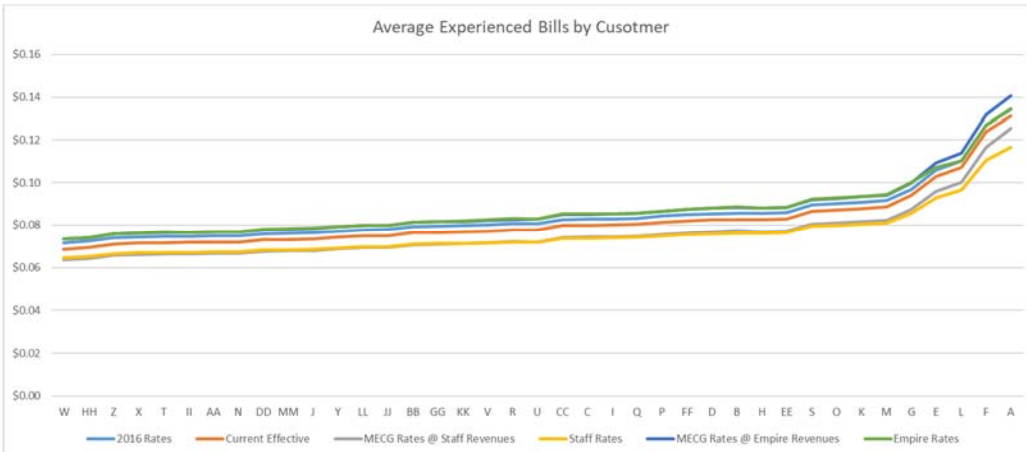
Q. If Empire's and MECG's recommendations to place any increases to the GP and LP rate schedules on the customer and demand elements is implemented, would the disparity between high and low load factor customer rates be impacted?

A. Yes, the disparity would grow. If the demand charges are increased disproportionately to the energy charges, or if the energy charges are reduced while the demand charges are held constant, the customers that are already paying the rates Ms. Maini characterizes as uncompetitive[6] would pay rates that are less competitive, while the customers that are already paying below-average rates would pay rates even more below average.

Q. Have you reviewed the actual bills currently experienced by customers served on the LP rate schedule and compared them to what those bills would be under each party's proposed rate design?

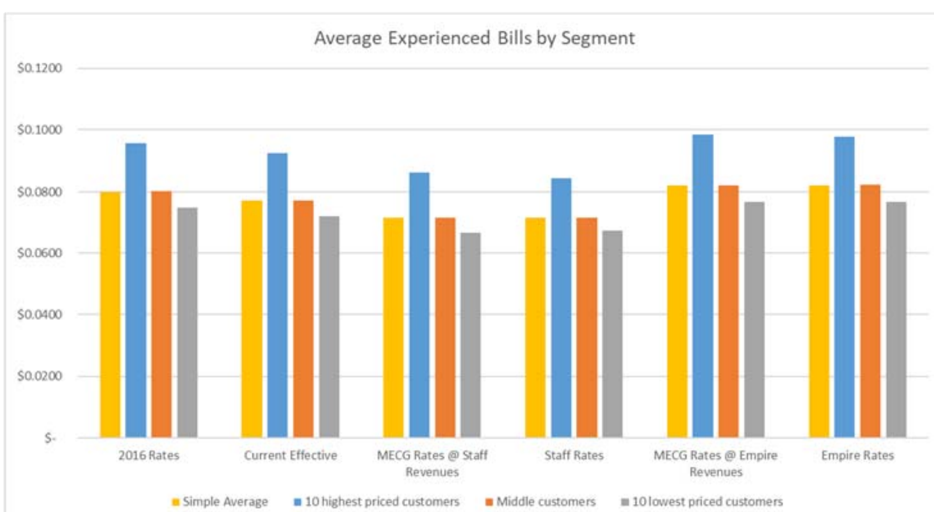
[6] Maini page 9.

A. Yes. The average experienced $/kWh by customer is graphed below for the rates implemented in the last rate case, those rates net of the currently effective tax rider, and what that value would be under each party's proposed rate design.



Q. Are the average experienced customer bills within the LP class uniform?

A. No. The average cost per kWh varies by LPS customer from approximately $0.0687 per kWh to approximately $0.1313 per kWh, a disparity of 91%. MECG's proposed rate design would increase this disparity to 97%, while Staff's would decrease it to 80%. The average $/kWh for the current 10 highest priced LP customers, the 10 lowest priced LP customers, and the remaining LP customers are provided below under the current and proposed rate designs.



PRAXAIR REVENUES AND RESULTS OF PRAXAIR-SPECIFIC CCOS

Q. Is it appropriate to "firm up" revenues for interruptible customers as discussed by Ms. Maini at page 23?

A. It depends. If a customer was interrupted at the time of peak in the test period, then it would be reasonable to either impute demand or to firm up revenues, consistent with the terms of the contract giving rise to the interruption. In its direct filing, Staff did not study Praxair's rate schedule as a distinct schedule from the Contract Transmission rate schedule. Rather, Staff studied hypothetical Contract Transmission load as described in the CCOS Report. Staff used firmed Praxair revenues in its study of the hypothetical load.

Q. Have you reviewed the impact of replacing generic Contract Transmission load with the Empire-provided Praxair hourly load on the overall CCOS results?

A. Yes. I replaced the generic Contract Transmission and Feed & Grain loads with the Empire-provided loads for Praxair and the PFM customers. The results are summarized in the table below:

	Residential	CB/SH	GP/TEB	LPS	PFM - Empire hourly	Praxair Actuals	Lighting
Cost of service by class	$245,067,428	$51,151,698	$121,756,457	$65,008,510	$179,889	$4,505,808	$4,600,056
CCoS net of other revenues	$225,458,993	$46,823,561	$110,255,850	$57,905,612	$174,887	$3,934,469	$4,363,886
Revenue produced by tariffed rates	$222,592,677	$54,735,420	$128,659,792	$66,825,848	$82,171	$4,588,888	$7,817,187
Tax credit	$8,505,642	$2,059,225	$4,729,095	$2,156,806	$2,319	$156,100	$245,100
Revenue produced by tariffed rates reduced by tax credit	$214,087,035	$52,676,195	$123,930,697	$64,669,042	$79,852	$4,432,788	$7,572,087
Rate of return provided by tariffed rates	6.71%	12.78%	12.49%	12.08%	-35.85%	12.71%	30.34%
Rate of return provided with tariffed rates reduced by tax credit	5.46%	11.31%	11.11%	10.88%	-36.92%	11.38%	28.70%
$ change to tariffed rates to equalize rate of return	$ 2,866,316	$ (7,911,859)	$ (18,403,942)	$ (8,920,236)	$ 92,716	$ (654,419)	$ (3,453,301)
$ change to tariffed rates reduced by tax credit to equalize rate of return	$ 11,371,958	$ (5,852,634)	$ (13,674,847)	$ (6,763,430)	$ 95,035	$ (498,319)	$ (3,208,201)
% change to tariffed rates to equalize rate of return	1.29%	-14.45%	-14.30%	-13.35%	112.83%	-14.26%	-44.18%
% change to tariffed rates reduced by tax credit to equalize rate of return	5.11%	-10.69%	-10.63%	-10.12%	115.66%	-10.86%	-41.04%
% (Under) Over contribution at current tariffed rates	-1.27%	16.90%	16.69%	15.40%	-53.01%	16.63%	79.13%
% (Under) Over contribution at current rates reduced by tax credit	-5.04%	12.50%	12.40%	11.68%	-54.34%	12.67%	73.52%

Q. Are the results from the study of a Praxair-specific load different enough from the results from the study of a generic Contract Transmission load that a different recommendation is appropriate if the Commission determines that it is more appropriate to rely on Praxair-specific loads than a generic load that would be more suitable to other potential Special Contract customers?

A. Yes. The results of including Praxair's revenue requirement in the rate schedules to be reduced in excess of the tax reduction decrease is provided below:

	Residential	CB/SH	GP/TEB	LPS	PFM - Empire hourly	Praxair Actuals	Lighting
Revenue produced by tariffed rates	$222,592,677	$54,735,420	$128,659,792	$66,825,848	$82,171	$4,588,888	$7,817,187
All classes except Feed & Grain reduced to current revenue net of taxes	$214,087,035	$52,676,195	$123,930,697	$64,669,042	**$82,171**	$4,432,788	$7,572,087
BB/SH, GP/TB, LP and Praxiar receive indicated shares of remaining decrease		25%	50%	23%		2%	
Additional reduction		$ 4,633,189	$ 9,266,379	$ 4,262,534		$ 370,655	
Class Revenue Requirement	$214,087,035	$48,043,006	$114,664,318	$60,406,508	$82,171	$4,062,133	$7,572,087
Rate of Return produced	5.46%	8.01%	8.42%	8.52%	-35.85%	8.22%	28.70%
Reduction by class	$8,505,642	$6,692,414	$13,995,474	$6,419,340	$0	$526,755	$245,100

<u>RELATIONSHIP OF LP TAIL BLOCK CHARGE AND MARKET ENERGY COSTS</u>

Q. Based on Maini's testimony at page 36, if a rate decrease is ordered in this case, is it likely that the cost to certain LP customers to obtain an additional kWh of energy will be less than the market value of that energy at the customer's meter?

A. Yes. I reviewed the loss-adjusted simple average cost of energy at wholesale by month for the hours of 8 am – 7 pm, and the hours of 7 pm – 8 am.

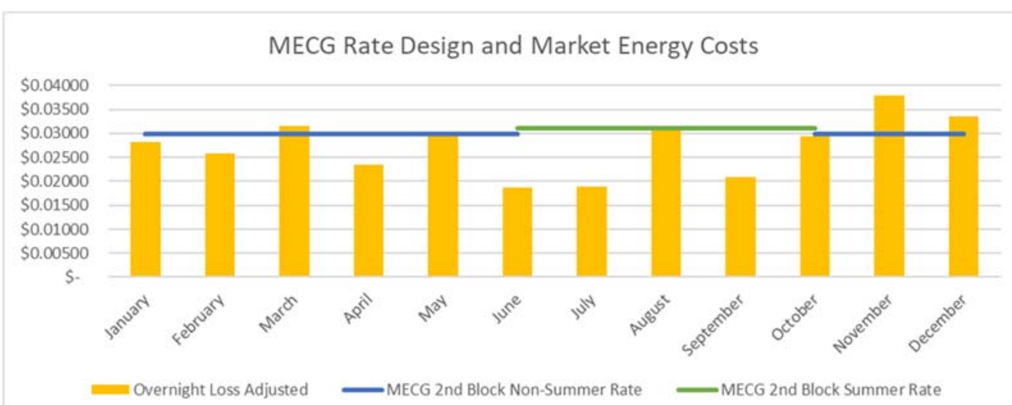
	January	February	March	April	May	June	July	August	September	October	November	December
Daytime	$ 30.54	$ 27.42	$ 37.19	$ 29.85	$ 38.00	$ 29.32	$ 29.31	$ 42.51	$ 29.06	$ 37.61	$ 44.47	$ 36.28
Overnight	$ 27.13	$ 24.76	$ 30.34	$ 22.58	$ 28.62	$ 18.00	$ 18.15	$ 29.90	$ 20.11	$ 28.25	$ 36.41	$ 32.23
Daytime Loss Adjusted	$ 31.79	$ 28.55	$ 38.72	$ 31.08	$ 39.56	$ 30.53	$ 30.52	$ 44.25	$ 30.26	$ 39.15	$ 46.30	$ 37.77
Overnight Loss Adjusted	$ 28.25	$ 25.78	$ 31.59	$ 23.50	$ 29.80	$ 18.74	$ 18.89	$ 31.13	$ 20.94	$ 29.41	$ 37.91	$ 33.56

I also applied the MECG proposed rate design described at page 36 of Ms. Maini's testimony to the Staff's recommended LPS revenue requirement, and to Empire's recommended LPS revenue requirement, to derive the rates summarized below. The rates resulting from the 2016 rate case and those rates net of the currently effective tax rider are included for reference:

LP	2016 Rates	Current Effective	MECG Rates @ Staff Revenues	Staff Rates	MECG Rates @ Empire Revenues	Empire Rates
Customer Charge	$ 283.55	$ 283.55	$ 283.55	$ 235.53	$ 325.00	$ 325.00
Summer Demand	$ 15.69	$ 15.69	$ 15.69	$ 13.03	$ 16.92	$ 15.69
Winter Demand	$ 8.66	$ 8.66	$ 8.66	$ 7.19	$ 9.34	$ 8.66
Facilities Demand	$ 1.88	$ 1.88	$ 1.88	$ 1.56	$ 2.03	$ 2.86
Summer 1st 350 HU	$ 0.06809	$ 0.06511	$ 0.05738	$ 0.06161	$ 0.06809	$ 0.06809
Summer Add. HU	$ 0.03683	$ 0.03385	$ 0.03104	$ 0.03565	$ 0.03683	$ 0.03683
Winter 1st 350 HU	$ 0.06048	$ 0.05750	$ 0.05096	$ 0.05529	$ 0.06048	$ 0.06048
Winter Add. HU	$ 0.03552	$ 0.03254	$ 0.02993	$ 0.03456	$ 0.03552	$ 0.03550

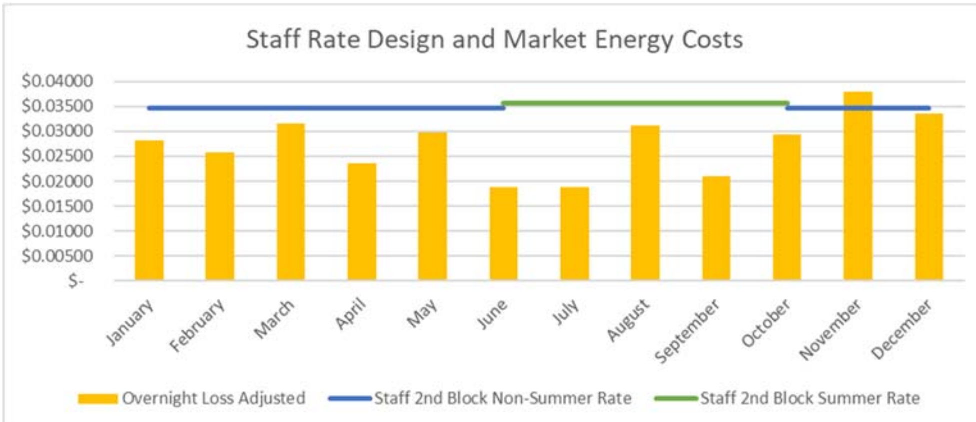
I compared the tail block rates produced by MECG's proposed rate design on Staff's LP revenue requirement, by season, to the average monthly loss-adjusted value of "overnight" energy.

	January	February	March	April	May	June	July	August	September	October	November	December
Daytime	$ 0.03054	$ 0.02742	$ 0.03719	$ 0.02985	$ 0.03800	$ 0.02932	$ 0.02931	$ 0.04251	$ 0.02906	$ 0.03761	$ 0.04447	$ 0.03628
Overnight	$ 0.02713	$ 0.02476	$ 0.03034	$ 0.02258	$ 0.02862	$ 0.01800	$ 0.01815	$ 0.02990	$ 0.02011	$ 0.02825	$ 0.03641	$ 0.03223
Daytime Loss Adjusted	$ 0.03179	$ 0.02855	$ 0.03872	$ 0.03108	$ 0.03956	$ 0.03053	$ 0.03052	$ 0.04425	$ 0.03026	$ 0.03915	$ 0.04630	$ 0.03777
Overnight Loss Adjusted	$ 0.02825	$ 0.02578	$ 0.03159	$ 0.02350	$ 0.02980	$ 0.01874	$ 0.01889	$ 0.03113	$ 0.02094	$ 0.02941	$ 0.03791	$ 0.03356
MECG 2nd Block Non-Summer Rate	$ 0.02993	$ 0.02993	$ 0.02993	$ 0.02993	$ 0.02993	$ 0.02993				$ 0.02993	$ 0.02993	$ 0.02993
MECG 2nd Block Summer Rate						$ 0.03104	$ 0.03104	$ 0.03104	$ 0.03104	$ 0.03104		



This analysis suggests that MECG's rate design would result in tail block energy sales failing to meet the market value of energy in three of the non-summer billing months, even before consideration of realtime balancing costs and the costs of ancillary services or other market costs that are allocated to load serving entities by load-ratio share.

While Staff's recommended tail block rate design at the recommended LP revenue requirement fails to meet the cost of energy in one month, it more consistently meets the cost of energy, with an allowance for other market costs.

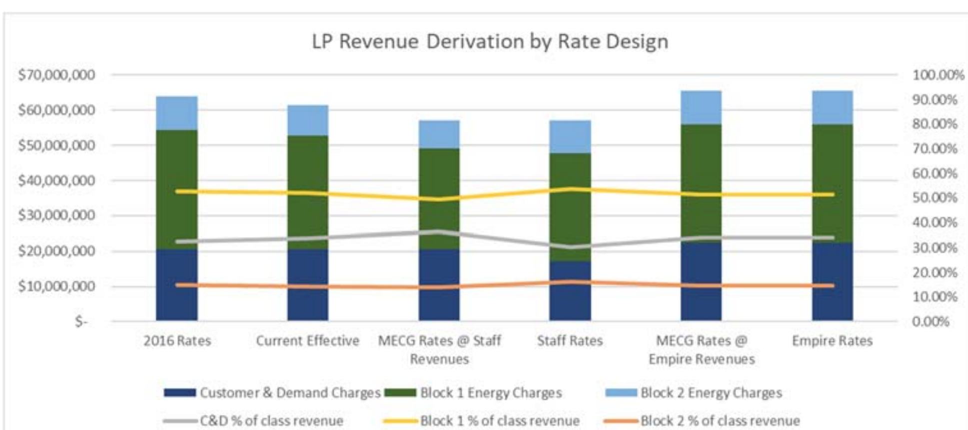


Q. Is it reasonable to assume that all usage in the LP tail block occurs in overnight hours?

A. No. Unfortunately, the hours use rate design fails to recognize the relationship between the time of energy consumption and the value of the energy consumed. Instead, it relies on simplified assumptions of the relationship between the coincidence of customer load and load factor.

Q. How do the parties' proposed LP revenue requirements and rate designs relate to the overall recovery of each component as a percent of total class recovery?

A. A summary of the revenue derivation by rate design is provided below:



CONCLUSION

Q. Are there factors that interplay in this case to support an overall cautious approach to major changes in relative rate recovery in this case?

A. Yes. First, given the concerns with data quality described by Michael Stahlman and Robin Kliethermes in their rebuttal testimony, no party's CCOS is of a particularly high quality, and billing determinants are uncertain. As Staff continues to investigate the estimated bill and data sufficiency concerns, it is possible that Staff will determine none of the three submitted CCOS studies are reliable due to the unavailability of reliable data to establish class and system peaks and billing determinants. Second, as I have illustrated in this testimony, tail block energy charges for the LP rate schedule are decreasing towards the marginal cost of energy, and the reliance on an NCP demand-charge for costs beyond local distribution system costs is misplaced. Third, as discussed in the CCOS Report, Empire has significant rate-switching and rate misalignment issues involving the CB and SH rate schedules, the GP and TEB rate schedules, and the PFM and GP/TEB rate schedules. Finally, as noted above, Empire will soon be deploying AMI. With proper AMI deployment and the ability to gather better customer data, the poor quality of Empire's load research and revenue data will be less significant – and – Empire will have the ability to implement rate schedules with time-variant rate structures.

Q. Based on the interplay of these factors, what is Staff's recommendation?

A. These factors emphasize the need for implementation of data retention measures, particularly as it relates to load research and hourly customer data. At this time Staff maintains its direct-filed CCOS recommendation.[7] Regardless of interclass revenue responsibility shifts that may be ordered in this case, Staff recommends that the CB and SH rate schedules be realigned for consistency of all rate elements except the charge for non-summer usage in excess of 700 kWh per customer per month. Staff recommends the GP and TEB rate schedules be consolidated, and that the Feed & Grain rate schedule rates be held constant in this case and that the Feed & Grain rate schedule be merged into the consolidated GP and TEB rate schedule in a future proceeding. Staff generally recommends that non-residential revenue requirement changes from the revenues produced by existing rates be implemented as an equal percentage adjustment to all rate elements as isolated for the voltage-adjusted cost of energy obtained to serve load.

In the event that the Commission orders a reduction to the Residential class in excess of the temporary tax rider amount, Staff recommends that the reduction be applied to the first energy block for each season, effectively creating a summer incline and reducing the winter decline. This approach would reduce the impact experienced by customers and facilitate a transition to time-variant rates in a future proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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[7] Staff recommends that the Feed & Grain rate schedule revert to its pre-tax reduction tariffed revenue level. Staff recommends that the Residential, Contract Transmission, and Lighting rate schedules retain the current level of revenue production which is net of the current temporary tax reduction rider, and that the CB/SH, GP/TEB, and LPS class revenue requirements be adjusted by the following process:

Reduce class revenue requirements by the level of the temporary tax reduction;

Determine the amount of additional reduction available after the above-referenced reductions have been applied, (approximately $18.5 million at Staff's recommended revenue requirement);

Further reduce the CB/SH and LPS revenue requirements by 25% each of the amount identified in step 2;

Further reduce the GP/TEB revenue requirements by 50% of the amount identified in step 2.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2019-0374

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Rebuttal Testimony*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 5th day of March 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070

D Suzie Mankin
Notary Public