Exhibit No.:	
Issues:	Cost of Service | Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Parties:	Missouri Industrial Energy Consumers and Midwest Energy Consumers' Group
Case No.:	ER-2014-0370
Date Testimony Prepared:	June 5, 2015

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	**))))))**	**Case No. ER-2014-0370**

Surrebuttal Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers
and
Midwest Energy Consumers' Group

June 5, 2015

BRUBAKER & ASSOCIATES, INC.

Project 9979

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)	**Case No. ER-2014-0370**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers and Midwest Energy Consumers' Group in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my surrebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0370.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

M E Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 4th day of June, 2015.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2019
Commission # 15024862

Tammy S Klossner

Notary Public

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

BEFORE THE PUBLIC SERVICE COMMISSION
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In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	**)**	**Case No. ER-2014-0370**

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

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A Yes. I have previously filed direct testimony on revenue requirement issues and both direct and rebuttal testimony on cost of service/rate design issues presented in this proceeding.

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

A Yes. This information is included in Appendix A to my revenue requirement direct testimony filed April 2, 2015.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC") and Midwest Energy Consumers' Group ("MECG"). These organizations' members purchase substantial amounts of electricity from Kansas City Power & Light Company ("KCPL") and the outcome of this proceeding will have an impact on their cost of electricity.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A The purpose of my surrebuttal testimony is to address the rebuttal testimonies of Staff witnesses Michael Scheperle, Sarah Kliethermes and Robin Kliethermes. I also briefly address the rebuttal testimony of KCPL witness Tim Rush.

Q PLEASE SUMMARIZE YOUR PRIMARY FINDINGS AND RECOMMENDATIONS.

A They may be summarized as follows:

1. The Detailed Base, Intermediate and Peak method ("Detailed BIP") that Staff continues to propose is founded upon erroneous assumptions about how a utility is planned and operated. Staff's approach pretends that there are essentially three sub-systems (base, intermediate and peak) and makes separate cost allocations of each to each customer class. In reality, however, a utility system actually is planned and operated on a portfolio basis and all plants are used to serve all customers.

2. Staff's reference to a BIP method sponsored by KCPL in Case No. ER-2014-0174 is incomplete in that it fails to report that KCPL has abandoned that methodology and adopted a much different methodology for purposes of this rate case.

3. Staff's use of market energy prices, instead of the embedded cost of energy, is completely at odds with the embedded cost regulatory paradigm that is used in Missouri. The market price benchmark that Staff uses in rate design exceeds the embedded energy-related costs by 67%. Designing rates using this benchmark for energy prices significantly over-allocates costs to high load factor customers in the LPS and LGS customer classes, and should be rejected.

4. My rate design proposal for LGS and LPS is fully justified by costs, and Staff agrees it would not cause rate shock to any customer.

5. KCPL witness Rush disagrees with my recommendation to recognize four different voltage levels for purposes of applying losses in the context of a fuel adjustment clause. He does not offer any substantive response to my proposal, stating simply, without further explanation, that he thinks "…two voltage levels … are sufficient…" (Rush Rebuttal Testimony, page 21). KCPL's two voltage levels overstate losses by between 50% and 137% for high voltage customers.

6. Staff witness Sarah Kliethermes' analysis of reasons for the increase in this case is clearly faulty. The evidence clearly shows that the major driver is increased fixed costs.

Class Cost of Service Issues

Q AT PAGE 1 OF HER REBUTTAL TESTIMONY, STAFF WITNESS SARAH KLIETHERMES REFERENCES PAGE 9 OF YOUR DIRECT TESTIMONY WHERE YOU STATE THAT NOT ALL KILOWATTHOURS ARE THE SAME. SHE THEN USES THAT TO LAUNCH INTO A DISCUSSION OF WHY SHE BELIEVES STAFF'S DETAILED BIP METHOD IS APPROPRIATE FOR THE ALLOCATION OF GENERATION PLANT. DOES YOUR STATEMENT AT PAGE 9 HAVE ANYTHING TO DO WITH THE ALLOCATION OF GENERATION COSTS?

A No. My discussion at page 9 was in the context of explaining the meaning of "functionalization" in the electric utility system and describing why customers taking service at different voltage levels impose different costs on the utility.

Q DO YOU AGREE WITH STAFF WITNESS SARAH KLIETHERMES' REBUTTAL TESTIMONY (AT THE BOTTOM OF PAGE 1 AND THE TOP OF PAGE 2) THAT STAFF'S COST OF SERVICE STUDY TAKES INTO ACCOUNT THE "REALITY" THAT THE COST OF PRODUCING A KWH OF ENERGY VARIES DEPENDING UPON WHAT PLANT IS PRODUCING THAT ENERGY AND WHAT PLANTS ARE OPERATING TO PRODUCE ENERGY AT A GIVEN TIME?

A No. While Staff likes to think of its Detailed BIP method as one that accomplishes this end, it actually ignores reality. The Detailed BIP method pretends that there are three separate groups of plants, or subsystems, that produce energy for the different classes of customers, and that the output of individual plants, or groups of plants, can be associated with service to portions of the load curve of the individual customer classes without regard to what plants are actually on line and generating, and the level at which they are generating, at any particular point in time. Under the guise of being more "detailed," the BIP method actually engages in gross over-simplifications and uses unrealistic assumptions about how a utility system is planned and operated.

Q PLEASE ELABORATE.

A No utility builds plants or groups of plants for the specific purpose of serving particular customer classes, or segments of its load. Rather, the combination of the loads of individual customer classes produces an overall utility load shape and service requirement. Whenever the utility is considering how to adjust its generation resource portfolio, it looks at its existing resources, the current and projected economics of different options, projected future loads, retirements, regulations and other important factors. It then selects the resources that best meet the needs of its customers giving due consideration to all of these factors. At no time is planning for generation resources based on loads of individual customer classes.

From an operational perspective, the utility operates the generation resources that it has (owned, purchased, or contracted for) in such a way as to provide reliable service at the lowest overall reasonable cost.

The approach accepted in the industry is to recognize the portfolio nature of a utility's generation resources and perform the allocations to customer classes accordingly. This is why all of the fixed costs of the generation resources typically are added together and allocated to customer classes on the basis of a reasonable measurement of demand (for example, A&E-4NCP) and all variable costs are added together and allocated to customer classes based on customer class energy requirements.

Q DO YOU HAVE ANY COMMENTS ABOUT STAFF WITNESS MICHAEL SCHEPERLE'S DISCUSSION OF THE REVENUE ALLOCATION FROM KCPL'S PRIOR GENERAL RATE CASE, CASE NO. ER-2012-0174?

A Yes, I do. He discusses a proposal by one of the parties in that case for an interclass revenue allocation adjustment that was implemented by the Commission. At pages 5 and 6 of his rebuttal testimony, Mr. Scheperle claims that my revenue neutral adjustments in this case will "contradict" what the Commission ordered in that case when it accepted an allocation proposal advanced by one of the parties.

Q IS MR. SCHEPERLE CORRECT?

A No. His statement is incorrect and misleading for two reasons. First, the cost of service results in this case show a much higher rate of return for the LPS class relative to the system average than was true in the prior case, even under Staff's faulty Detailed BIP methodology. Second, the cost of service study used by the Commission in developing the revenue allocation in the last case was sponsored by KCPL, and KCPL has abandoned that cost of service (BIP) methodology in its filing in this case.

Accordingly, no meaningful cost indicators can be drawn from the prior KCPL rate case.

Rate Design

Q PUTTING ASIDE FOR THE MOMENT THE ASSUMPTIONS MADE WHEN ALLOCATING COSTS AMONG CUSTOMER CLASSES, DO YOU HAVE ISSUES WITH RESPECT TO HOW STAFF HAS DEFINED ENERGY COSTS FOR PURPOSES OF ITS RATE DESIGN?

A Yes. Staff defines energy costs for rate design purposes as equal to wholesale market costs. I have a major disagreement with Staff in this regard.

Q WHAT IS THE NATURE OF THE DISAGREEMENT?

A Missouri is an embedded cost jurisdiction for purposes of revenue requirements and for purposes of cost of service. Embedded costs are also typically used as a benchmark in determining the customer, demand and energy costs for each class. KCPL does not simply buy power from the SPP to serve its load. Rather, it must build or acquire sufficient capacity to serve its load and must use fuel to generate power needed to serve that load, supplemented with net power purchases.

Q DOES STAFF ACKNOWLEDGE THAT IT IS APPROPRIATE TO ALLOCATE ACTUAL EMBEDDED VARIABLE COST AMONG CUSTOMER CLASSES FOR PURPOSES OF COST OF SERVICE?

A Yes. Staff witness Sarah Kliethermes acknowledges this on page 3 of her rebuttal testimony.

> "Q. Is it reasonable to allocate costs between classes using the assumption that KCPL generates its own energy to serve its own load?
>
> A. Yes. All parties calculate KCPL's net jurisdictional revenue requirement on the assumption that KCPL generates its own energy using its own resources to serve its own Missouri load. Because each party's CCOS studies are conducted to allocate

> that revenue requirement, it is not unreasonable to allocate costs among the classes using the assumption that KCPL generates its own energy using its own resources to serve its own Missouri load."

Q DO YOU AGREE WITH STAFF'S POSITION ON ALLOCATION?

A Yes. While we may differ on some of the components of the embedded energy cost, we agree in concept that it is appropriate to allocate KCPL's actual embedded cost of generation, both fixed costs and variable costs, to customer classes.

Q WHERE DO YOU DISAGREE?

A In the very next answer on page 3 of her rebuttal testimony, she states as follows regarding these embedded energy cost revenue requirement components:

> "However, these costs are not relevant to calculating the cost of energy to serve KCPL's customers, as is discussed in detail below concerning the cost-causation underlying energy charges."

She goes on to note that the energy-related costs contained in KCPL's revenue requirement (net of off-system sales revenues) are the costs KCPL incurs to generate electricity.

She then jumps to the following unwarranted conclusion on page 4 of her rebuttal testimony:

> "Because of KCPL's participation in the SPP integrated energy market, the cost to supply a customer with a kWh of energy is the cost of energy at the relevant KCPL node at the time that kWh is consumed (adjusted for transmission, ancillary services, and losses)."

Q DO YOU AGREE WITH HER CHARACTERIZATION?

A No. While it is true that on an hourly basis KCPL does clear all of its generation and all of its load in the SPP energy market, this does not mean KCPL purchases all of the power required to serve its customers. If that were the case, it would mean that the fuel and purchased power costs for power paid by customers would be equal to the wholesale market price of power – and not to KCPL's cost to produce power in its own generating units, supplemented by occasional wholesale market purchases. It also would mean that the entire output of KCPL's generation facilities would be dedicated to the production of market sales – and not to serving KCPL's retail customers. Under such circumstances, no fuel cost would be assigned to KCPL's retail customers – only purchased power costs. In addition, there would be no basis to include in rate base KCPL's investment in generation facilities, since those facilities would no longer be serving the company's retail customers.

Furthermore, Ms. Kliethermes' understanding is contrary to FERC Order 668 which specifies how hourly clearing in RTO markets of load and generation must be addressed. Under Order 668, a utility must net its SPP-cleared load and generation in each hour and report the net as either a sale for resale or a power purchase. In any given hour, therefore, a utility has either an off-system sale to SPP or a power purchase from SPP – but not both.

The reality is that KCPL offers all of its generation and bids all of its load into the SPP energy market in coordination with each other, on behalf of native load customers. The purpose of doing so is to supplement the energy available from its own generation with power purchases, and to engage in economy sales of excess energy from its own generation facilities.

Q WHAT DOES THIS MEAN IN TERMS OF STAFF'S PROPOSALS?

A Staff uses its misperception of the relationship between KCPL and SPP to justify defining the energy component that it views as appropriate for rate design purposes as the hourly SPP market cost of energy. In fact, though, KCPL invests in generation plant and purchases fuel to serve load, and that is why those costs are figured into the rates that its customers pay. Staff's misperception is further belied by the fact that, in most hours, KCPL is a net seller into the SPP energy market, and not a net buyer. Staff's fundamental flaw from a rate design perspective is the unwarranted reliance upon hourly market prices in SPP to measure the adequacy of the energy rates in KCPL's retail tariffs.

Q HOW MUCH OF AN ERROR DOES STAFF'S APPROACH INTRODUCE INTO THE RATE DESIGN ANALYSIS?

A It is significant. By using the market price proxy for energy cost, Staff must necessarily understate the other components of cost of service in order to avoid allowing KCPL to over-collect. As an example, Staff shows on page 13 of its rate design and class cost of service report, in Table 4, functionalized costs by class. Adding together the amounts attributed to "production energy" for the individual customer classes produces a total production energy component of $250 million. This is out of a total revenue requirement of approximately $900 million.

Based on the same approximately $900 million revenue requirement, KCPL determines an energy component (with which I agree) of approximately $150 million. Accordingly, Staff's misplaced reliance upon market energy prices for purposes of rate design analysis overstates the energy component by $100 million or by about two-thirds (67%).

Staff's approach is a material departure from generally accepted procedures in the industry, and, if applied, would result in a material distortion in rate design. Since it inflates the cost of energy and deflates the cost of capacity, it would over-price high load factor customers and under-price low load factor customers. This is not only inequitable, but it would reduce the incentive for customers to minimize their peak demands because the cost consequences to the customer of imposing higher demands would be under-priced relative to the cost of serving it.

Q AT PAGE 4 OF HER REBUTTAL TESTIMONY WITNESS SARAH KLIETHERMES CRITICIZES YOU FOR MENTIONING THAT THE AVERAGE VARIABLE COST IS LESS THAN 1.7¢/KWH WITHOUT DISCUSSING THE FACT THAT THIS CALCULATION RELATES TO KCPL'S COST TO GENERATE ENERGY, NOT ITS COST TO OBTAIN ENERGY THROUGH SPP. HOW DO YOU RESPOND?

A I respond as I did above. Her criticism is based on misconceptions and is unwarranted. 1.7¢/kWh is KCPL's true and accurate average variable cost of electric supply, and should be used as a benchmark for establishing energy charges in KCPL's embedded cost-based retail rates.

Q ARE THERE ANY CIRCUMSTANCES IN WHICH THE MARKET COST IS RELEVANT?

A Yes. The market cost is relevant in circumstances other than full embedded cost ratemaking, such as when an analysis is being conducted to determine an appropriate price to be charged to an "at risk" customer in order to preserve the load on the system, rather than to lose the load. In such circumstances, a comparison between the price to be charged to the customer and the price that power would fetch in the market (SPP market price) is a relevant consideration. However, for the traditional embedded cost ratemaking that we are doing in this case, it is not a relevant factor.

Q HAVE YOU REVIEWED TABLE 1 ON PAGE 5 OF WITNESS SARAH KLIETHERMES' REBUTTAL TESTIMONY?

A Yes. This table purports to be a measurement of "average cost of energy" by customer class under certain different assumed load shapes, and also shows a total dollar cost of energy that Staff attributes to each customer class.

Q DO YOU AGREE THAT THIS TABLE REPRESENTS THE "AVERAGE COST OF ENERGY"?

A No, I do not. The table is based on Staff's market prices of energy, and does not represent the average cost of energy as that term normally is used in connection with class cost of service determinations.

Q COULD TABLE 1 BE ADJUSTED TO REFLECT MARKET ENERGY COSTS MORE ACCURATELY?

A Yes. Instead of using average market costs as Ms. Kliethermes has done, a more accurate indication would require taking into account off-system sales revenues as well as the cost of operating KCPL's generation fleet.

Q HAVE YOU MADE THESE ADJUSTMENTS?

A Yes. Table 1 below adjusts Ms. Kliethermes' rebuttal Table 1 to also incorporate a consideration of off-system sales revenue and the cost of generation.

While not as accurate or relevant as a traditional embedded cost analysis, the revised Table 1 at least includes all of the major components of market transactions, namely hourly prices, cost to generate and revenues from off-system sales. Note that the entries on the next to the last line of the table, denominating "class load factor annual" are less than $17/MWh (1.7¢/kWh) for all of the major customer classes.

Table 1[1]						
Net Market Cost of Energy at Meter (voltage-adjusted) per MWh by Class By Season						
	Residential	**SGS**	**MGS**	**LGS**	**LPS**	**Lighting**
Perfect Load Factor Summer:	$ 14.00	$ 14.00	$ 14.00	$ 13.96	$ 13.73	$ 14.00
Perfect Load Factor Non-Summer:	$ 18.79	$ 18.79	$ 18.78	$ 18.73	$ 18.42	$ 18.79
Perfect Load Factor Annual:	$ 17.17	$ 17.17	$ 17.17	$ 17.12	$ 16.84	$ 17.17
Class Load Factor Summer:	$ 13.66	$ 13.64	$ 13.61	$ 13.71	$ 13.66	$ 15.94
Class Load Factor Non-Summer:	$ 18.74	$ 18.69	$ 18.72	$ 18.68	$ 18.41	$ 18.65
Class Load Factor Annual:	$ 16.64	$ 16.82	$ 16.76	$ 16.94	$ 16.68	$ 17.86
Cost of Energy at Generation:	$ 43,002,015	$ 7,212,465	$ 19,496,905	$ 39,804,642	$ 37,313,886	$ 1,603,909

[1] Table 1 from the rebuttal testimony of Sarah Kliethermes, adjusted to reflect net market cost of energy

Q HAVE YOU REVIEWED TABLE 2 ON PAGE 7 OF MS. KLIETHERMES' REBUTTAL TESTIMONY?

A Yes. The first line on Table 2 is taken from Table 4 in Staff's Cost of Service report, and the second line is taken from Table 1 in Ms. Kliethermes' rebuttal testimony.

Q WHAT IS YOUR ASSESSMENT OF TABLE 2?

A As noted, the second line of data is taken from Ms. Kliethermes' rebuttal Table 1 and accordingly contains all of the shortcoming associated with her Table 1 calculations, which I have discussed above. The data for the first line, which comes from Table 4 on page 13 of the Staff report, is described as "…functionalization in dollars by class and by the percent of each function in that class' class cost of service." A further description of the energy component from this table is provided on page 12 of the Staff report which says that production energy costs "…are those costs related directly to the customer's consumption of electrical energy (i.e., kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs."

Q IS THIS AN ACCURATE DESCRIPTION OF WHAT IS INCLUDED IN THE PRODUCTION ENERGY COST LINE IN TABLE 4 ON PAGE 13 OF STAFF'S REPORT?

A No, this is a misleading description. In point of fact, what is included on that line (which forms the basis for the first line on Ms. Kliethermes' rebuttal Table 2) is not only the cost attributed to generation for retail customer load, but it also includes the cost of generation associated with energy that is sold off-system. So, in other words, this represents the total energy cost, not only for retail customers as the title might suggest, but for off-system sales as well. This is at best misleading, and any reliance upon the data as class costs would lead to erroneous conclusions.

Q HAVE YOU PREPARED A CORRECTED VERSION OF TABLE 2?

A Yes. It appears below. In the first line of data is a corrected version of Staff's functionalized embedded energy-related costs to reflect an offset for off-system sales revenue associated with the additional energy cost that Staff has allocated to retail customer classes. Note that all of these values are about $10/MWh lower than Staff's inflated numbers. The second line of data is taken from revised Table 1, above.

Table 2[1]

Average (voltage-adjusted) Embedded Cost of Energy Production Compared to Net Market Costs

	Residential	SGS	MGS	LGS	LPS	Lighting
Functionalized Embedded Energy-Related Costs $/MWh @ Customer Meter:[2]	$ 19.00	$ 20.59	$ 19.56	$ 18.29	$ 16.62	$ 20.67
Net Market Cost of Energy $/MWh @ Customer Meter:	$ 16.64	$ 16.82	$ 16.76	$ 16.94	$ 16.68	$ 17.86

[1] Table 2 from the rebuttal testimony of Sarah Kliethermes, adjusted to reflect net market cost of energy (Table 1) and corrected functionalized embedded energy costs (Table 4 of Staff Report)

[2] Staff's designated embedded energy costs include income taxes and A&G expense and therefore are overstated by more than $2.00/MWh.

Q I NOTE THAT YOU HAVE NOT INCLUDED THE LAST THREE LINES OF STAFF'S TABLE 2. WHY IS THAT?

A The last three lines were a comparison between the first line and the second line, and this additional information has no particular meaning and adds no value to the analysis.

Q NOTWITHSTANDING THESE ISSUES, DO STAFF'S ANALYSES NEVERTHELESS SHOW THAT OFF-PEAK ENERGY CHARGES IN THE LPS AND LGS TARIFFS ARE IN EXCESS OF MARKET ENERGY PRICES?

A Yes. Table 3 on page 8 of Staff witness Sarah Kliethermes' rebuttal testimony shows off-peak market energy costs ranging from about $22/MWh at transmission voltage level to about $23/MWh at secondary voltage level.

This should be compared to the tail block rates in the tariffs. The LPS tail block energy rate currently is about $25/MWh, and the tail block energy charge for the LGS rates ranges between $35/MWh in the winter and $42/MWh in the summer. Obviously, all of these numbers are in excess of even the market cost of energy, which itself is an overstated benchmark for purposes of evaluating the adequacy of tail block rates.

Q WHAT NUMBER SHOULD BE USED TO EVALUATE THE ADEQUACY OF THE TAIL BLOCK RATES?

A The actual true average embedded cost of energy, which is about $17/MWh (1.7¢/kWh), is a reasonable proxy. Were we to look at the average embedded cost during off-peak hours versus the average during all hours, we would find that the average cost during off-peak hours is even lower than these amounts.

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF STAFF WITNESS ROBIN KLIETHERMES?

A Yes. At page 8 of her rebuttal testimony she discusses the LPS and LGS rate design and addresses my recommendation.

Q DOES SHE GENERALLY AGREE WITH YOUR EXPLANATION OF HOW THESE RATES WORK?

A Yes, she does. However, she points out that the correlations between load factor and the time that energy is used is not perfect – a point which I would readily acknowledge. However, it generally is true that just as a result of the ordinary nature of commerce, the higher load factor customers, particularly those who have significant usage in the tail block of the rate (load factor over 50%) tend to have their maximum demands during the day and purchase considerable amounts of energy during off-peak hours. The only way that a low load factor customer could have considerable usage during off-peak hours would be if the customer had its maximum demand at night. Certainly, there can be some customers like this, but it would be unlikely that we would find many customers who were imposing their maximum demands on the utility system at night.

Q DO YOU HAVE ANY EVIDENCE TO SUPPORT THAT?

A Yes. I looked at KCPL's load research data and, for LGS and LPS, compared the class coincident peak (which occurs when the system has its peak – principally during the daytime) with the sum of the maximum demands of the individual customers in each class in order to determine the extent to which these maximum customer demands are correlated with class coincident peaks. Schedule MEB-COS-SR-1 shows these results.

A high ratio of class coincident peak to the sum of individual customer maximum demands indicates that the maximum customer demands are occurring near the times of the system coincident peaks. As an example, for the LPS schedule, note that the monthly ratios range from 77% to 89%, and average 83% for the year. This is a clear indication that, for the most part, maximum demands of customers are occurring during the hours when the utility system peaks, and not during night or weekend times. This adds further credence to the association of third block energy usage with off-peak times, and supports my rate design recommendation.

Q DOES MR. SCHEPERLE HAVE ANY COMMENTS WITH RESPECT TO YOUR LPS AND LGS RATE DESIGN PROPOSAL?

A Yes. First, he comments at the bottom of page 5 of his rebuttal testimony that my recommendation would "distort" rate continuity between the small, medium and large general service rate schedules.

Q DO YOU AGREE?

A No. The redesign recommendation I make in this case is identical to the rate design recommendation I have made in the last several KCPL rate cases. There has been no reported problem of rate continuity as a result of those rate design changes being implemented, and Mr. Scheperle provides absolutely no evidence that there would be any distortion as a result of adopting my rate design recommendation in this case.

Q WHAT OTHER COMMENTS DID STAFF MAKE ABOUT YOUR LPS AND LGS RATE DESIGN RECOMMENDATION?

A On pages 13 and 14 of his rebuttal testimony, Mr. Scheperle recites my recommendation and states that although Staff has not opposed such a concept in the past, it does not support it in this case "at this time."

Q DOES STAFF AGREE THAT YOUR RATE DESIGN RECOMMENDATION WOULD NOT CREATE RATE SHOCK FOR ANY CUSTOMER ON THE LPS TARIFF?

A Yes. Mr. Scheperle says so at page 14 of his rebuttal testimony:

> "Staff analyzed each customer on the LPS rate tariff schedule and believes that rate shock would not occur for any customer."

In response to Data Request No. 0595 (MIEC 2.18), Mr. Scheperle confirmed that his conclusion applies to my rate design recommendation.

Q DID STAFF HAVE ANY OTHER SUGGESTED CRITERIA FOR EVALUATING RATE DESIGNS?

A Yes. At the same point in his rebuttal testimony, Mr. Scheperle also raised the question of whether or not each rate component covers marginal cost. As I have testified above, I do not believe this is a valid criteria to apply in an embedded cost state. Notwithstanding that objection, the evidence which I have provided previously in this surrebuttal testimony clearly demonstrates that at current rates the tail block charges of both the LGS and LPS tariffs are in excess of even Staff's evaluated calculation of marginal energy cost. Accordingly, this should not be an impediment or road block to acceptance of my rate design recommendations.

Loss Factors in Fuel Adjustment Clause

Q IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT IF THE COMMISSION APPROVES AN FAC FOR KCPL THAT IT SHOULD DISTINGUISH LOSSES AT FOUR DIFFERENT VOLTAGE LEVELS, INSTEAD OF TWO AS PROPOSED BY KCPL. DID ANYONE RESPOND TO THIS PROPOSAL?

A Only witness Tim Rush for KCPL.

Q WHAT DID MR. RUSH SAY?

A He didn't say anything substantive, he merely asserted that he believed that the two voltage levels "…are sufficient to appropriately distinguish the cost recovery." (Rush Rebuttal Testimony, page 21).

Q DO YOU AGREE?

A No. As shown on Direct Testimony Schedule MEB-COS-9, lines 42 and 43, the difference in loss factor between the primary voltage level and the substation voltage level is 1.22 percentage points (3.707% - 2.483% = 1.22%),[1] or 50% of the substation level loss factor (1.22% ÷ 2.483%[2] = 49%). The difference between the transmission level losses and primary losses is even greater at 2.14 percentage points, or 137% of the transmission voltage level losses (3.707%[3] - 1.565%[4] = 2.142%; 2.142% ÷ 1.565% = 137%).

[1]See lines 42 and 43, column (3).
[2]See line 43, column (3).
[3]See line 42, column (3).
[4]See line 44, column (3).

Reasons for this Rate Increase

Q DID STAFF WITNESS SARAH KLIETHERMES TAKE ISSUE WITH YOUR STATEMENT THAT THIS RATE CASE PRIMARILY IS DRIVEN BY CAPACITY ADDITIONS, SO THAT MOST OF THE INCREASE IN REVENUE REQUIREMENT IS CAPACITY-RELATED?

A Yes. She does so on pages 10 and 11 of her rebuttal testimony.

Q IS HER ANALYSIS CORRECT?

A No. In her analysis she compares certain revenue requirement components in this case to those in the prior case, Case No. ER-2014-0174. In so doing, she failed to recognize a major difference in the categorization by KCPL between this case and the last case of fuel, purchased power expense, and off-system revenues. She states on page 11 of her rebuttal testimony that the difference in expenses between the two cases is $427 million.[5] However, $378 million of the difference in expense is attributable to changes in the fuel and purchased power categories. What she fails to realize, however, is that other revenues (primarily off-system sales revenues) increased by $365 million. The increase in fuel and purchased power expense is essentially offset by the increase in other revenues. In fact, the net change in this category is only $13 million. By failing to recognize KCPL's different categorizations of expenses and revenues between the two cases, Ms. Kliethermes reaches a completely erroneous conclusion.

[5]Ms. Kliethermes mixed up her calculated difference in rate base with her calculated difference in expenses. The calculated difference in expenses is $422 million.

Q IS THERE ANY INDEPENDENT SOURCE OF INFORMATION THAT DELINEATES THE REASONS FOR THE REQUESTED INCREASE IN REVENUES IN THIS CASE?

A Yes. KCPL provided such an analysis in Appendix 2 to its Application in this case. For convenience, a copy of that appendix is included as Schedule MEB-COS-SR-2.

Q WHAT DOES IT SHOW?

A In this presentation, KCPL analyzed changes in costs and the reasons for its requested rate increase and explained what makes up the requested $121 million rate increase. Notably, $47 million is attributable to increased fixed costs associated with La Cygne, $29 million is associated with increased fixed costs on Wolf Creek, $17 million is associated with Other Infrastructure Investments, and $10 million is associated with increased Property Taxes as a result of the above investments. These are all clearly fixed costs. The other $18 million is attributable to Transmission costs ($17 million) and Other costs ($1 million). This other $18 million is the maximum amount of cost increase that could be something other than fixed costs. Accordingly, my conclusion that the requested rate increase is primarily driven by additional fixed costs is also supported by KCPL's own analysis [$103 million out of $121 million (85%)]. Ms. Kliethermes' claims to the contrary are inaccurate.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

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KANSAS CITY POWER & LIGHT COMPANY

Load Research Coincident Peak (CP) and Maximum Diversified Demand (MDD) of Customers

		LGS			LPS		
Line	Month	CP (MW)	MDD (MW)	Ratio	CP (MW)	MDD (MW)	Ratio
		(1)	(2)	(3)	(4)	(5)	(6)
1	January	343	499	69%	233	294	79%
2	February	329	481	68%	239	298	80%
3	March	310	493	63%	231	301	77%
4	April	311	442	70%	273	313	87%
5	May	321	450	71%	270	348	78%
6	June	365	471	77%	294	353	83%
7	July	358	469	76%	316	355	89%
8	August	349	483	72%	299	354	85%
9	September	374	494	76%	302	345	88%
10	October	351	474	74%	280	324	86%
11	November	277	455	61%	235	296	80%
12	December	319	482	66%	236	294	80%
13	Total	4,005	5,693	70%	3,209	3,873	83%

Note:
(1) CP is the demand of all customers on the rate at the time of the KCPL monthly peak.
(2) MDD is the summation of the maximum demands of all of the customers on the rate.

Source: KCPL Allocators MO Rev 10-9-14 Avg-Pk 4 CP - not included in 12-1-14 wkps.xls

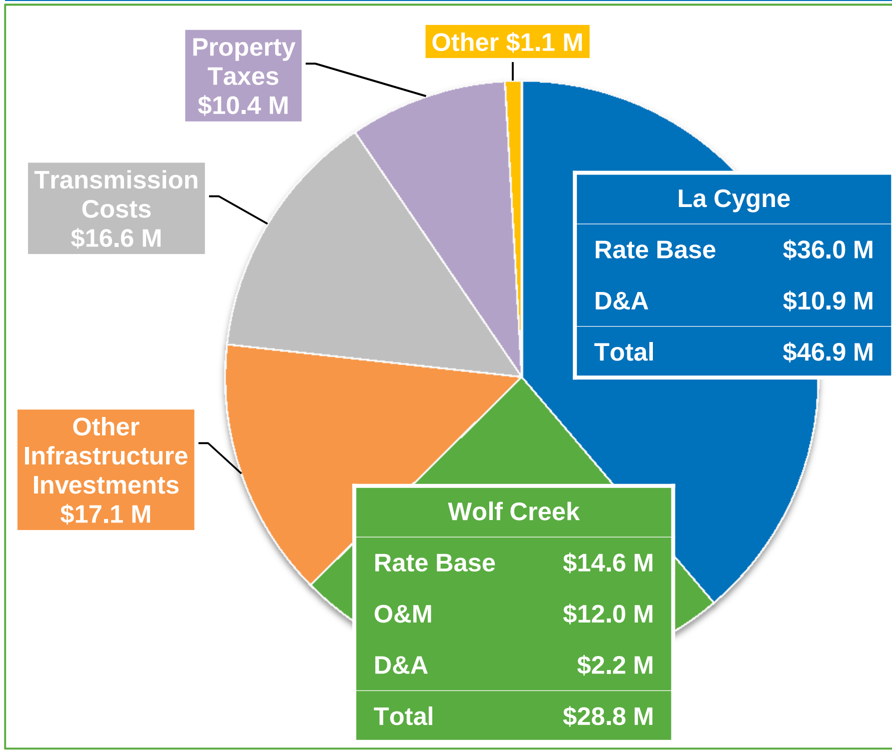
KCP&L – Missouri Rate Case Summary

Case Number	Date Filed	Requested Increase (in Millions)	Requested Increase (Percent)	Rate Base (in Millions)	ROE	Cost of Debt	Rate – Making Equity Ratio	Capital Structure ROR	Anticipated Effective Date of New Rates
ER-2014-0370	10/30/14	$120.9	15.75%	$2,557[1]	10.3%	5.56%	50.36%	7.94%	9/30/15

Rate Case Attributes:

- Test year ended March 31, 2014 with May 31, 2015 true-up date
- Primary drivers of increase:
  - Environmental investments at the La Cygne Generating Station and upgrades to the Wolf Creek Nuclear Generating Station
  - New infrastructure investments to ensure reliability, security and dependable service to customers
  - Transmission costs and property taxes
- Requested authorization to implement:
  - Fuel adjustment clause (FAC) including transmission costs
  - Property tax tracker
  - Critical Infrastructure Protection Standards (CIPS) / Cybersecurity tracker
  - Vegetation management tracker

$120.9 Million Rate Increase Request:



La Cygne	
Rate Base	$36.0 M
D&A	$10.9 M
Total	$46.9 M

Wolf Creek	
Rate Base	$14.6 M
O&M	$12.0 M
D&A	$2.2 M
Total	$28.8 M

[1] Projected rate base is approximately $505 million or 25% higher than at the conclusion of the last rate case

GREAT PLAINS ENERGY

Appendix 2

Schedule MEB-COS-SR-2