AG Exhibit 1

OAG EXHIBIT 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	)))	**CASE NO. 2007-00089**

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

AFFIDAVIT

The affiant, William Steven Seelye, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089, in the Matter of: An Adjustment of the Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony in such case.

William Steven Seelye

STATE OF INDIANA)
)
COUNTY OF MARION)

Subscribed and sworn to before me by William Steven Seelye, this the 18th day of April, 2007.

My Commission Expires: 2/14/2015

Notary Public, State at Large, Indiana

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor Delta Natural Gas Company Inc.'s ("Delta's") proposed rates for natural gas service; to describe the proposed allocation of the revenue increase; to sponsor the fully allocated class cost of service study based on Delta's embedded costs for the 12 months ended December 31, 2006; to sponsor the temperature normalization adjustment; and to sponsor Delta's depreciation study supporting the proposed depreciation rates and the pro-forma adjustment to depreciation expenses.

Q. Please summarize your testimony.

A. Delta is proposing to increase base rate revenues by $5,562,341. The Company has a large residential customer base, and, as a result, Delta is proposing to allocate $3,847,230 of the increase to the residential class. The Company is proposing to collect these revenues by increasing the residential customer charge. By recovering all of the residential increase through the customer charge, we are proposing to move in the direction of a "straight fixed variable" rate design, which is a methodology that has been adopted in other regulatory jurisdictions. More specifically, Delta is proposing to recover through the monthly customer charge most of the customer-related costs identified in the cost of service study. The Prime Group prepared a fully allocated, embedded cost of service study for Delta's test-year operations using a cost of service methodology that has been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to determine the contribution that each customer class is making towards Delta's overall rate of return. Rates of return are computed for each rate class. Delta was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service. Delta is also proposing to make a temperature normalization adjustment to sales and transportation volumes not covered by the Company's Weather Normalization Adjustment ("WNA") clause. In addition, Delta is proposing to change a number of its depreciation rates based on the depreciation study included as an exhibit to my testimony.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Rate Design and the Allocation of the Increase, (III) Cost of Service Study, (IV) Temperature Normalization Adjustment, (V) Revenue Adjustment to Reflect Year-End Customers, and (VI) Depreciation Study and Depreciation Expense Adjustment.

I. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have performed cost of service and rate studies for over 100 investor-owned utilities, rural electric cooperatives, and municipal utilities. I have also developed or modified fuel and purchased power adjustment mechanisms for numerous electric and gas utilities, including integrated investor-owned utilities, integrated municipal utilities and distribution cooperatives. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes, on many occasions. Concerning my background related to the subject matters addressed in this proceeding, I have testified in other proceedings regarding rate design, revenue requirements, cost of service studies, pro-forma adjustments and depreciation expenses. A listing of my testimony is included in Seelye Exhibit 1.

II. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

Q. Is Delta proposing to change the relationship between the customer charge and volumetric charge for the residential rate class?

A. Yes. The Company is proposing a significant increase in its customer charge. Delta has a traditional residential base rate design consisting of a customer charge and a volumetric charge. This type of rate design is referred to as a “two-part” rate. Under this design, a portion of Delta's non-gas costs are collected through a monthly fixed customer charge, which does not vary with usage, and a volumetric charge applied to each Ccf used. Delta's residential customer charge is currently $9.80 per month and the non-gas volumetric charge is $0.41592 per Ccf (or $4.1592 per Mcf). Gas costs are recovered through the Gas Cost Recovery Rate (GCR), which is a volumetric charge.

Some regulatory jurisdictions have shifted from a traditional two-part rate design to a design in which all non-gas costs are recovered through a fixed monthly customer charge. This type of rate structure is referred to as a "straight fixed variable" rate design. This rate design evolved from pipeline rate designs that recovered all fixed costs through a fixed charge and all variable costs through a volumetric charge. Because non-gas costs are *fixed* for a gas distributor, and do not vary with the amount of gas purchased by its customers, all non-gas costs are recovered through a *fixed* monthly customer charge under a straight fixed variable rate structure.

The Missouri Public Service Commission ("Missouri Commission") recently adopted a straight fixed variable rate design for Atmos Energy Corporation (*Case No. GR-2006-0387*, Order dated February 22, 2007) and Missouri Gas Energy, a division of Southern Union Company (*Case No. GR-2006-0422*, Order dated March 22, 2007). The straight fixed variable rate design was proposed by the Missouri Commission Staff in the Atmos proceeding. A straight fixed variable rate design is also used by the Atlanta Gas Light Company in Georgia.

In the Atmos Proceeding, the Missouri Commission accepted the Staff's recommendation to eliminate the traditional two-part rate structure and to adopt instead a straight fixed variable design because collecting fixed costs through a volumetric charge:

- Creates unnecessary volatility in customer bills by collecting too much cost in the winter months;
- Sends incorrect price signals to residential customers;
- Forces residential customers whose usage is greater than the average to pay more than the cost of service, while allowing smaller customers to pay less than the cost of service;
- Provides no incentive for the utilities to promote conservation.

(*Atmos Energy Corporation, Case No. GR-2006-0387*, Order dated February 22, 2007, pp. 19-20.)

Q. Is Delta proposing a straight fixed variable rate design?

A. No. Although Delta is not recommending a straight fixed variable rate design, the Company is proposing to move significantly in that direction. Specifically, Delta is proposing to leave the volumetric charge at the current level and recover all of the residential revenue increase in the customer charge. Under a straight fixed variable design the non-gas volumetric charge would be eliminated and all of Delta's non-gas costs would be recovered through the monthly customer charge.

Although Delta's proposed residential rate will fall far short of recovering all fixed costs in the customer charge, it will come reasonably close to recovering the customer-related costs identified in the fully allocated class cost of service study submitted in this proceeding. In the cost of service study, Delta's non-gas fixed costs are classified as either customer-related or demand-related. With a straight fixed variable rate design adopted in Missouri and

Georgia all of these costs – both customer-related and demand-related fixed costs – would be recovered through the monthly customer charge. In this proceeding Delta is proposing to recover most – but not all – of its customer-related costs through the monthly customer charge. Delta's customer-related cost for residential customers is currently $24.16 per month. However, the Company is only charging $9.80 per month, or 41% of the customer-related costs that were identified in the cost of service study. In this proceeding, Delta is proposing to increase the monthly customer charge to $19.74, which represents 82% of the customer-related costs identified in the cost of service study. Although this increase in the customer charge is far less than it would be with straight fixed variable rate design, Delta's proposal is a significant shift in that direction.

Q. What would the customer charge be under a straight fixed variable design?

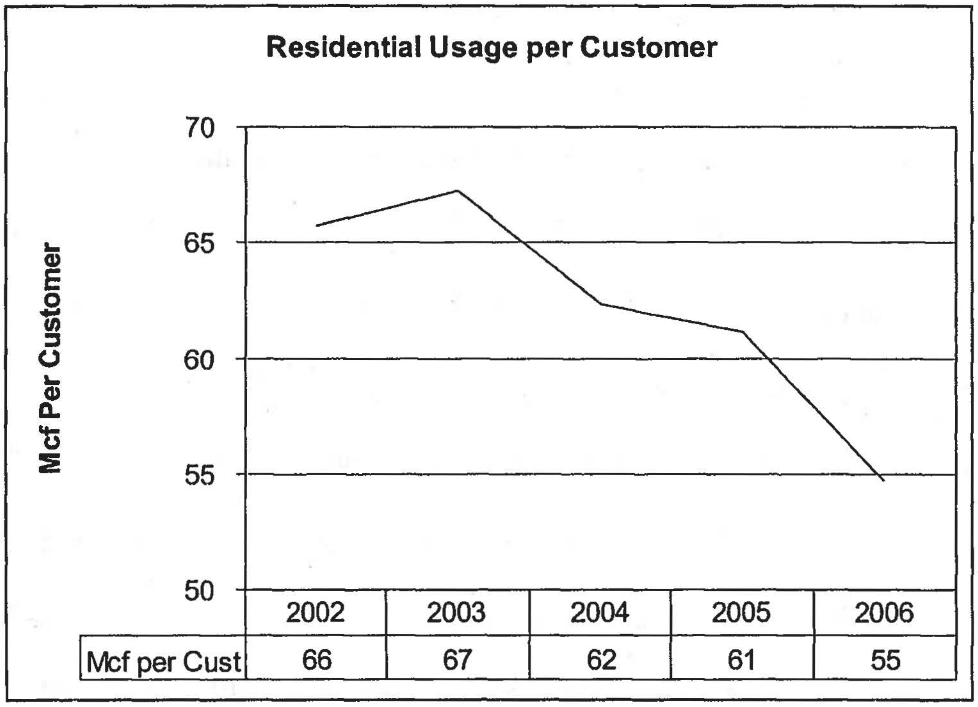
A. Under a straight fixed variable rate as was ordered by the Missouri Commission, the monthly customer charge would be $38.94, compared to the $19.74 charge proposed by Delta. Even with a $19.74 customer charge, approximately 50% of Delta's fixed costs will continue to be recovered through a volumetric charge.

Q. What are the benefits of recovering most of the customer-related costs through the customer charge?

A. Recovering more of Delta's customer-related costs through the fixed monthly customer charge will better reflect the actual cost of service through rates and will thus send a more accurate price signal to customers. In addition, Delta's proposed customer charge will reduce the volatility in customer bills by lowering the amount charged during the winter.

The Company's proposal will also eliminate rate subsidies within the residential customer class. Currently, customers with lower than average usage are being subsidized by customers with higher than average usage. Based on data that I have seen from other gas utilities, including a gas utility in the region, low income customers – contrary to a common misconception – tend to purchase more gas than the average customer. The likely reason for this is that low income customers often have poorly insulated homes, which causes their gas usage to be higher than the average even though their homes may have less square footage than the average. When customer-related costs are recovered through the volumetric charge, low income customers who use more than the average will subsidize customers who use less natural gas than the average.

Yet another advantage of Delta's proposal – and one which should be an important consideration for the Company – is that a higher customer charge should help mitigate the erosion in margins that Delta has been experiencing for a number of years. Delta's average Mcf per customer has been trending down for many years now. As shown in the following graph, in just four years the average residential usage has gone from 66 Mcf per customer in 2002 to 55 Mcf in 2006.



Because a large percentage of Delta's fixed costs have been recovered through a volumetric charge, the decline in customer usage has the effect of reducing the recovery of fixed costs and eroding the Company's earnings. Delta has not had an opportunity to earn the rate of return on equity authorized by the Commission in Delta's last three rate cases, and decreasing sales volumes have contributed heavily to this trend. Recovering more fixed costs through the customer charge should help mitigate this erosion in earnings. Furthermore, increasing the customer charge will work in tandem with the Experimental Customer Rate Stabilization ("CRS") Mechanism to provide Delta a reasonable opportunity to earn a fair, just and reasonable rate of return while preventing customers from being overcharged. Increasing the customer charge will in no way work at cross purposes with the CRS but, rather, will enhance the effectiveness of the proposed mechanism.

Q. Will the proposed rate design better position the Company to encourage conservation on the part of customers?

A. Yes it will, when considered in conjunction with the CRS and the proposed Conservation/ Efficiency Program (CEP) Cost Recovery Mechanism. Recovering a significant portion of fixed costs through a volumetric charge works to penalize the Company when customers conserve. Essentially all of Delta's non-gas costs are fixed and do not vary as customer volumes go up or down. With a significant portion of fixed costs recovered through volumetric charges, the Company's financial results are adversely affected from consumer conservation. Because Delta is not proposing to eliminate the volumetric charge for non-gas costs through the adoption a straight fixed variable rate design, the Company's non-gas revenues will continue to go down as a result of conservation, but not nearly as much as they would if Delta had proposed an increase in the volumetric charge. Furthermore, the adoption of the CRS and CEP Cost Recovery Mechanisms proposed by Delta will help position the Company so that it is not financially harmed by conservation on the part of customers. All three of these measures – increasing the customer charge, implementing the CRS Mechanism, and adopting the CEP Mechanism – work together as an integrated effort to help maintain Delta's financial integrity while encouraging customers to use less natural gas.

Q. Have you prepared an exhibit reconstructing Delta's test-year billing units?

A. Yes. In order to develop Delta's proposed rates it was necessary to reconstruct test-year billing units. The reconstruction of Delta's billing determinants is shown on Seelye Exhibit 2.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase apportioned to the individual customer classes?

A. Delta is proposing to increase its annual revenues by $5,641,650. As shown on Seelye Exhibit 3 , this amount would result in an increase of 9.2% in total operating revenue. In addition to requesting an increase in gas service rates, Delta is also proposing to increase the collection charge, reconnection charge, and bad check charge, all of which result in an increase in miscellaneous revenue of $79,309.

The proposed rates apportion the revenue increase among the customer classes as follows:

TABLE 1
Proposed Gas Increase

Customer Class	Proposed Increase	Percentage
Residential	$ 3,847,230	12.5%
Small Non-Residential	489,319	5.2%
Large Non-Residential	1,130,216	7.3%
Off-System Transportation	95,575	3.8%
Total Sales and Transportation	$ 5,562,341	9.2%

As shown on Seelye Exhibit 4, the effects on individual class revenues were determined by applying both the current and proposed charges to the adjusted billing determinants for each customer class.

Q. What was the basic underlying information that supported the proposed allocation among rate classes?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall return earned by the Company. The cost of service study indicated that the individual class rates of return ranged between 3.69%

and 19.11% as compared to an overall adjusted actual return on rate base of 5.71%, with residential being the lowest at 3.69%. This indicates a need to increase the revenues collected from the residential class more than the other classes. The rates of return for all of the rate classes except the special contracts were significantly higher than for residential. The cost of service study also showed that the earned return for the interruptible and off-system transportation rates were extremely high when compared to the other classes of service. Because the rate of return for the residential class is significantly below Delta's proposed overall rate of return of 8.82%, Delta is proposing to increase the residential rate by a larger percentage than the other classes in order to bring the residential rate of return more in line with the overall rate of return. The special contracts are served under fixed-price arrangements; therefore, none of the revenue increase will be allocated to these customers. Delta does not propose to increase the rates for the interruptible rate class because of the high rates of return for this rate class. With a rate of return of 19.11% for interruptible service, a rate increase for this rate class cannot be justified. Delta is proposing increases for the small and large non-residential rate classes that will result in a rate of return of around 10%, based on the results of the cost of service study, and the Company is proposing an increase in the off-system transportation rate that will produce a rate of return of approximately 9%.

Q. Is it important to consider competitive issues when designing rates?

A. Yes. It is extremely important to take into consideration the competitive pressures facing the utility when designing rates. Utility customers have many more options than they did in the past, and they are also becoming more sophisticated in how to utilize the various competitive products that are now available to them. However, the natural gas industry has always experienced keen competition from alternative fuels. When customers have alternatives (and the ability to substitute fuel oil for natural gas is only one example), gas distribution companies must be able to ensure that the revenues contributed by these customers are retained as long as they make some contribution to the utility's fixed costs. Industrial and commercial customers generally have more options than residential customers. Therefore, it is important not to charge rates to commercial and industrial customers that are uncompetitive and exceed the cost of providing service. Otherwise, large commercial and industrial customers will leave the system, forcing residential and small commercial customers, who have fewer options, to pay for fixed costs that are left stranded by the departing customers. Unlike volumetric costs, such as the cost of the gas commodity that a distribution company buys for its customers, a utility's fixed costs generally do not disappear if it sells less gas, but instead are spread over a lower volume of gas, thus causing the utility's rates to increase. Therefore, if a utility loses several large high-load factor industrial customers, then the utility's fixed costs do not suddenly disappear but are shifted to the remaining customers in future rate proceedings. On the other hand, if the utility can attract high-load factor customers or, even better, customers with off-peak usage, then the utility's fixed costs can be spread over a larger volume of gas thus causing gas rates to go down, benefiting all customers. Again, that is why it is important for Delta to keep the rates applicable to price sensitive customers as competitive as possible while considering the cost of serving these customers.

Q. What were the ratemaking objectives in developing the proposed gas rates?

A. As explained earlier, we tried to develop rates that more closely reflect the cost of providing service. Therefore, one of our key objectives was to bring the unit charges more in line with the unit costs derived from the cost of service study. Thus, we developed rates that moved the charges toward the unit costs indicated by the cost of service study.

Q. Have you analyzed the customer-related costs for Delta's rate classes?

A. Yes. Page 20 of Seelye Exhibit 6 shows the unit customer-related costs for each rate class based on the results of the cost of service study. The customer-related cost for each rate class was derived by calculating the customer-related cost of service, or "revenue requirement" and dividing this amount by the number of customers. Delta's cost of service includes (1) return on investment, (2) income taxes, (3) operation and maintenance expenses, (4) depreciation expenses, and (5) other taxes. The proposed overall rate of return of 8.82% was used to calculate the unit cost.

Q. What are the proposed unit charges for the small non-residential rate class?

A. Delta is proposing a customer charge of $25.00 per customer per month and a flat commodity charge of $0.4159 for all Ccf. The current rate consists of a customer charge of $20.00 and commodity charge of $0.3795 per Ccf.

Q. What are the proposed unit charges for the large non-residential rate class?

A. Delta is proposing a customer charge of $100.00 per customer per month and a commodity charge of $0.4159 for the first 2,000 Ccf, $0.2510 for the next 8,000 Ccf, $0.1714 for the next 40,000 Ccf, $0.1314 for the next 50,000 Ccf, and $0.1114 for all usage over 100,000 Ccf. The first block was set at the same level as the first block in the small non-residential rate, and the current charge differentials between the blocks were maintained.

Q. Is Delta proposing to modify the interruptible or off-system transportation rate schedules?

A. No. As indicated earlier, rate increases for these services cannot be justified in light of the high class rates of return.

Q. Is Delta proposing to increase the off-system transportation rate?

A. Yes. We are proposing to increase the off-system transportation rate from $0.26 to $0.27 per dekatherm.

III. GAS COST OF SERVICE

Q. Did you prepare a cost of service study for Delta's natural gas operations based on financial and operating results for the 12 months ended December 31, 2006?

A. Yes. I supervised and participated in the preparation of a fully allocated, embedded cost of service study for natural gas service based on Delta's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the 12 months ended December 31, 2006. The Commission in other rate case proceedings has accepted the methodology used in Delta's cost of service study. The objective in performing the cost of service study is to determine the rate of return on rate base that Delta is earning from each customer class, which provides an indication as to whether Delta's service rates reflect the cost of providing service to each customer class.

Q. Have you ever prepared an embedded cost of service study?

A. Yes, on many occasions. While employed at LG&E, I prepared numerous gas and electric cost of service studies, many of which were filed in rate cases before the Commission. Since leaving LG&E, I have prepared or supervised the preparation of well over 100 embedded cost of service studies for electric, gas and water utilities. In Kentucky, I supervised and participated in the preparation of gas cost of service studies for Delta (Case No. 99-176 and Case No. 2004-00067) and LG&E (Case No. 2003-00433 and Case No. 2000-080).

Q. Was the same methodology used in the cost of service study submitted in this proceeding that was used in the cost of service study filed by Delta in Case No. 2004-00067?

A. Yes.

Q. Did the Commission accept Delta's cost of service study filed in Case No. 2004-00067?

A. Yes it did, as set forth on page 57 of the Commission's November 10, 2004 Order in Case No. 2004-00067.

Q. Did you develop the model used to perform Delta's cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The cost of service study was prepared using the following basic procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups, (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to Delta's rate classes. This is a standard approach utilized in the preparation of embedded cost of service studies for gas utilities.

Q. What is the purpose of functionally assigning costs?

A. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a mechanism for separating assignable costs from joint costs, which must be allocated.

Q. What functional groups were used in the natural gas cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Storage, (2) Transmission, (3) Distribution Commodity, (4) Distribution Structures and Equipment, (5) Distribution Mains, (6) Services, (7) Meters, (8) Customer Accounts, and (9) Customer Service Expense.

Q. How were costs classified as commodity related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics which give rise to the costs can serve as a basis for allocation. Costs classified as *commodity related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand related. Distribution Structures and Equipment costs were classified as demand-related. Costs related to Distribution Mains were classified as demand-related and customer-related using the zero intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were all classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost of service study?

A. Yes. Seelye Exhibit 5 shows the results of the first two steps of the cost of service study: functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, Delta's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 5, Delta's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28 of Seelye Exhibit 5. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are shown on pages 29 and 30 of Seelye Exhibit 5. The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors." The results of the class allocation step of the cost of service study are included in Seelye Exhibit 6. The costs shown in the column labeled "Total System" in Seelye Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 5. The column labeled "Ref" in Seelye Exhibit 6 provides a reference to the results included in Seelye Exhibit 5.

Q. Please describe the allocation factors used in the gas cost of service study.

A. The following allocation factors were used in the gas cost of service study:

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on expected winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the expected winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Seelye Exhibit 7.

- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the basis of design-day demands determined at Delta's -3 degree F design-day mean temperature.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at Delta's -3 degree F design day mean temperature. These demands were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment will be discussed later in my testimony.

- **DEM05** is used to allocate the demand-related portion of the cost of distribution mains and represents maximum class demands determined at the design day mean temperature.

- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of December through March.)

- **COM03** is used to allocate Transmission commodity-related costs and represents annual throughput volumes (including both sales and transportation).

- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation) of customers served on the distribution system.

- **CUST01** is used to allocate the customer-related portion of

Delta's distribution mains and represents the year-end number of customers.

- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST03** is used to allocate Meters and is based on the estimated cost of meters and meter installation costs per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and is determined on the basis of the average number of customers.

- **CUST05** is used to allocate customer service expenses using the same allocation factor used to allocate Accounts 901, 902, 903, and 905 in CUST04.

Q. How are mains typically classified between demand and customer costs?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, a "minimum" standard pipe size is selected and the minimum system is obtained by pricing all of the distribution mains at the unit cost of this minimum size pipe. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology, rather than the minimum system methodology, was used to determine the customer component of mains. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size main to determine the customer component. In the zero intercept methodology, a zero-diameter pipe is the absolute minimum system.

Q. What is the theory behind the zero intercept methodology?

A. The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost ($/ft) of mains and the gas flow capability of the pipe, which is proportionate to its diameter. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the pipe,

x is the size of the pipe, and

a, b are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a pipe with zero diameter (or pipe with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of mains that is invariant to the size (and load carrying capability) of the pipe.

Like most gas distribution systems, the number of feet of mains on Delta's system is not uniformly distributed over all sizes of pipe. For example, Delta has over 4.5 million feet of 2-inch plastic mains, but only 74 thousand feet of 3-inch plastic mains. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Using a weighted regression analysis, the cost and diameter of each size pipe is, in effect, weighted by the number of feet of installed pipe. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i(y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor (in this case the feet of pipe) for each size of pipe, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Seelye Exhibit 8 is the zero-intercept analysis used in this study. The zero-intercept unit cost of $3.39 per foot pipe is applied to the total feet of mains in the analysis to determine the customer cost component. The listing on page 1 of the analysis indicates that the coefficient of determination R-squared for mains is 0.9194. The coefficient of determination is a relative measure of the goodness of fit, where a coefficient of 0.0 indicates no linear correlation between the independent variable and dependent variable and a coefficient of 1.0 indicates perfect linear correlation.

Q. Has the Commission accepted the use of the zero-intercept methodology in previous cases?

A. Yes, on many occasions. The Commission accepted the methodology in Delta's last rate case (Case No. 2004-00067). LG&E utilized the zero-intercept methodology in the cost of service studies submitted in its last two base rate cases (Case No. 2000-080 and Case No. 90-158) in which the Commission has issued orders and the Commission found them to be reasonable. The Commission also found the embedded cost of service study submitted by The Union Light Heat and Power in its gas base rate case (Case No. 2001-00092), which utilized a zero-intercept methodology, to be reasonable. In my experience, the zero-intercept methodology is the predominant method used in Kentucky and is used widely in other jurisdictions.

Q. Please summarize the results of the gas cost of service study.

A. The following table (Table 2) summarizes the rates of return on net cost rate base for each customer class before and after reflecting the rate adjustments proposed by Delta. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential	3.69%	7.88%
Small Non-Residential	7.03%	9.26%
Large Non-Residential	7.28%	10.10%
Interruptible	19.11%	19.11%
Special Contracts	3.23%	3.23%
Off-System Transportation	8.16%	8.81%
Total System	5.71%	8.82%

Q. Is the current rate of return for the residential class adequate?

A. No. As shown in Table 1, the rate of return for the residential class is below the rates of return for the other customer classes. Delta's overall adjusted rate of return is 5.17%, while the rate of return for the residential class is only 3.69%. In my opinion, Delta should be allowed to charge rates that bring the residential rate of return more in line with the overall rate of return.

Q. Would Delta's proposed rates move the company toward bringing the class rates of return closer together?

A. Yes. As can be seen in Table 1, the residential rates proposed by Delta result in a pro-forma rate of return of 7.88%, which brings the residential class within approximately 1 percentage point of the proposed overall rate of return of 8.82% (compared to 1.5 percentage points, currently).

IV. TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Please explain the calculations and methodology used to determine the temperature normalization adjustment to test period revenue.

A. Delta has a Weather Normalization Adjustment ("WNA") clause that automatically adjusts the commodity charge to reflect normal temperatures. The WNA clause is applicable to residential and small non-residential customers and is currently applied during the months of December through April. Because the WNA automatically normalizes customer billings for these two rate classes during the months of December through April it is not necessary to perform a temperature normalization adjustment for these two classes during these months. However, it is necessary to perform a temperature normalization adjustment for the residential and small non-residential customer classes to reflect the heating months not covered by the WNA. Additionally, it is necessary to perform a temperature normalization adjustment for rate classes not billed under the WNA, namely, large non-residential and interruptible rate classes.

Q. How was the gas temperature normalization adjustment performed for the rate classes not billed under the WNA?

A. A standard temperature normalization adjustment covering the entire heating season was performed for the large non-residential and interruptible rate classes. Heating degree days related to cycle billed customer deliveries were 196 below the 30-year average Weather Bureau heating-degree days of 4,662, where the 30-year average was determined using the period ended November 2006. Thus, Delta's actual revenues were understated due to warmer than normal temperatures experienced during the test period. The degree-day data used for purposes of calculating the temperature normalization adjustment was obtained from the Lexington, Kentucky weather station.

The first step in computing the temperature-related variance in deliveries was to determine the annual non-temperature sensitive and temperature sensitive volumes for each rate class. The determination of the non-temperature sensitive volumes was based on the gas deliveries that occurred in July and August since those months had the lowest volumes and also had no heating degree days. The volumes in those two months were then multiplied by six to calculate an annual non-temperature sensitive load that was deducted from total deliveries to arrive at the annual temperature sensitive volumes.

The next step was to determine the volumetric adjustment required to normalize deliveries to reflect normal temperatures. The annual temperature sensitive volumes were divided by the actual heating degree days (4,662 for billing cycle customers) in the test period and the resulting Mcf per degree day was then multiplied by the degree-day departure from normal (196 HDDs) to arrive at the volumetric adjustment for each rate class. In the final step, the volumetric adjustment for each rate class was applied to the applicable distribution component (rate per Mcf) for each rate schedule not billed under the WNA.

Q. **How was the gas temperature normalization adjustment performed for the residential and small non-residential rate classes, which are billed under the WNA?**

A. The same methodology was used for the residential and small non-residential rate classes except that the difference in degree days was determined only for the months outside of the period when the WNA is applied. In other words the temperature normalization was only applied to the 7 non-WNA months of May through November. Since the WNA adjusts customer volumes during the months of December through April, it was not necessary to make a temperature normalization adjustment during these months. During the months of May through November, actual heating degree days related to cycle billed customer deliveries were 54 above the 30-year average Weather Bureau heating-degree days of 712 for those months. This difference was then used in the calculation of the temperature normalization adjustment for the residential and small non-residential rate classes.

Q. Please summarize the total impact of the gas temperature normalization adjustment.

A. The temperature normalization adjustment results in a net increase of $106,452 to Delta's gas operating revenue. The calculation of this amount is summarized on Seelye Exhibit 9.

V. REVENUE ADJUSTMENT TO REFLECT YEAR-END CUSTOMERS

Q. Is Delta proposing to make a pro-forma adjustment to reflect the number of customers served at the end of the year?

A. No, and it respectfully asks that a year-end customer adjustment not be made in this proceeding. The purpose of such an adjustment is to normalize annual revenues to reflect a going forward level of customers. The rationale for a year-end adjustment is to compare the number of customers at the end of the test year to the average number of customers during the test year. If the year-end level is higher than the average then it is assumed that the Company is adding customers and that the year-end level of customers and associated revenues is more appropriate than the average test-year level on a going-forward basis for purposes of setting rates. Delta does not believe that the year-end level of customers reflects an appropriate going forward level of customers. In fact, it is likely that the revenues associated with the year-end level will overstate Delta's going forward revenue because the year-end level of customers will almost certainly be higher than the average number of customers during the first full year that the rates go into effect.

In this proceeding, the year-end level of customers is not higher than the average because of customer growth, but, rather, because of the selection of the 12 months ended December as the test year. A significant number of customers disconnect service during the summer months and return to the system during the winter months. Because the test year in this proceeding ends in December – which is a winter month – using the year-end level of customers overstates the customer level that should be used for purposes of normalization. As can be seen from the following table, Delta is not adding customers. In fact, Delta has been consistently losing customers over the past several years:

TABLE 3
Average Customers by Year

Year	Total Average Customers
2002	40,185
2003	39,765
2004	39,358
2005	38,981
2006	38,117

Based on this trend, one could expect that the number of customers served by Delta will continue to decrease, thus suggesting that a downward adjustment should be made to normalize revenues to reflect the number of customers served on a going forward basis. Delta is not proposing to make a downward revenue adjustment to reflect this trend, and asks that the Commission not make a year-end adjustment in this proceeding. The standard year-end adjustment is included in Seelye Exhibit 10 in the event that the Commission rejects the recommendation not to make a year-end adjustment.

VI. DEPRECIATION STUDY AND DEPRECIATION EXPENSE ADJUSTMENT

Q. Did you supervise the preparation of a depreciation study for Delta?

A. Yes.

Q. Was a standard methodology used to determine the depreciation accrual rates?

A. Yes. Where suitable information was available, the Simulated Plant Record (SPR) methodology was used to determine the survivor curve that best fit the plant retirement data for Delta's plant accounts. The SPR methodology is described in *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners and in other publications. Where sufficient data were not available, or the resulting statistics were not satisfactory, we relied heavily on comparisons to the survivor curves and depreciation rates utilized by neighboring gas utilities. The methodology used to develop the depreciation accrual rates is described in more detail in the report included in Seelye Exhibit 11.

Q. Was the same methodology used in this depreciation study as in study filed by Delta in its last rate case (Case No. 2004-00067)?

A. Yes. The Company submitted a depreciation study and made some corrections to the study in rebuttal testimony filed in that proceeding. The Commission accepted the corrected depreciation study filed by the Company. The depreciation study filed in this proceeding follows the methodology used in the corrected study that was approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

AG Exhibit 2

OAG EXHIBIT 2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))))	CASE NO. 2016-00370

DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE MANAGING PARTNER THE PRIME GROUP, LLC

Filed: November 23, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. By whom and in what capacity are you employed?

A. I am the managing partner for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Kentucky Utilities Company ("KU" or "the Company"), which provides electric service in Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the proposed allocation of the revenue increases for KU's operations; (ii) to support KU's proposed rates, and (iii) to sponsor the fully allocated cost of service studies based on KU's embedded cost of providing service for the fully forecasted test year, which is the 12 months ending June 30, 2018.

Q. Please summarize your testimony.

A. In developing its proposed rates in this proceeding, KU relied heavily on the results of the cost of service studies. For the most part, the Company's class cost of service studies were prepared using methodologies that have been accepted by the Kentucky

Public Service Commission ("Commission") in previous rate cases. In this proceeding, however, KU is presenting two versions of the cost of service study. In one version, the Base-Intermediate-Peak ("BIP") methodology used in prior cost of service studies for time-differentiating and allocating fixed production costs will be utilized. In the other version, a methodology is used to allocate fixed production costs that is more reflective of the way generation resources are planned by the Company. This alternative version allocates costs by weighting hourly class loads by the hourly Loss of Load Probability ("LOLP"), which is a key measure that has been used by KU and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies'") for planning their generation resources for many years. I will present information comparing the results of the LOLP version of the cost of service study to the BIP version that has been used in prior rate cases.

The purpose of a class cost of service study is to determine the contribution that each customer class is making towards KU's overall rate of return. Rates of return are calculated for each rate class. A class cost of service study is also used as a tool for developing unit charges for electric service. Cost of service is a standard measure of reasonableness for utility rate design.

In this filing, KU is proposing rate design changes to begin to address fundamental changes that are taking place within the electric utility industry. Across the United States, electric utilities are beginning to see competitive pressures from various forms of distributed generation (e.g., solar generation, natural gas generation, and wind generation). As a result of customers installing behind-the-meter electric generation, and also customers finding ways to conserve energy or use energy more efficiently, many utilities are experiencing steep declines in their sales per customer. Regardless of the environmental benefits that may result from these initiatives, it is important that the utility ensure that the rate design is structured in a way that recovers the actual cost of serving customers who install distributed generation and pursue behind-the-meter energy efficiency measures. With improperly designed rates, it is possible for the utility's other customers (for example, customers who cannot or do not install distributed generation) to be unduly penalized by having costs improperly shifted onto them from customers who install distributed generation or reduce their energy consumption. Therefore, it is important for the utility to design its rates so that the actual cost of providing service is recovered through rates even when customers reduce their energy consumption but still require the same utility infrastructure to serve them. For example, if a customer reduces its energy consumption through the installation of solar generation, but falls back on the utility to deliver power to the customer when the solar generation is not operating, the utility still needs the same distribution infrastructure to serve the customer even though the customer might be using less energy.

KU is therefore taking some initial steps toward implementing rate changes that will provide appropriate and equitable cost recovery in a changing utility industry. We are proposing to separate out the infrastructure and variable cost components of the energy charge for Residential Service (RS), General Service (GS) and other two-part rates that include only a customer charge and an energy charge.

The purpose of this change in the presentation of these rate schedules is to provide more information to customers, stakeholders and employees about which costs are avoidable through the installation of distributed generation (i.e., the variable cost component) and which costs are less likely to be avoided (i.e., the fixed cost component). We are also proposing changes to the large customer rates, specifically Time-of-Day Secondary Service (TODS), Time-of-Day Primary Service (TODP), Retail Transmission Service (RTS), and Fluctuating Load Service (FLS), to provide better assurance that the actual costs of transmission and distribution service are recovered from customers that install distributed generation. I will discuss these changes in greater detail later in my testimony.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 16(7) and 16(8)?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

- Cost of Service Studies — Section 16(7)(v) — Tab 52
- Revenue Summary — Section 16(8)(m) — Tab 66

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Rate Design and the Allocation of the Increase, (IV) Increase in Miscellaneous Service Charges, and (VI) Cost of Service Study.

II. QUALIFICATIONS

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From 2014 through 2015 I completed an additional 12 hours of Electrical Engineering coursework at the University of Louisville's Speed School of Engineering (courses in computer design, microcontroller programming, digital signal processing, and computer communications). In addition, from 2012 through 2015, I was an instructor at Louisville's Walden School and a private tutor and instructor in advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.

Concerning my professional background, from May 1979 until July 1996, I was employed by LG&E. From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed or supervised the preparation of cost of service and rate studies for over 150 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. Therefore, including my time at LG&E, I have more than 35 years of experience in the utility industry. A more detailed description of my qualifications is included in Exhibit WSS-1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 50 regulatory and court proceedings in 13 different jurisdictions including the Kentucky Public Service Commission. I have testified on behalf of both KU and LG&E on numerous occasions. A listing of my testimony in other proceedings is included in Exhibit WSS-1.

Q. Please describe your work and testimony experience as they relate to topics addressed in your testimony?

A. I have performed or supervised the development of cost of service and rate studies for over 150 utilities throughout North America. I have also testified on numerous occasions regarding the rates proposed by electric, gas and water utilities, including KU.

III. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE REVENUE INCREASE

Q. Please summarize how KU proposes to allocate the revenue increase to the classes of service.

A. KU relied on the results of the cost of service studies to determine the revenue increases allocated to the classes of service. Specifically, larger relative portions of the overall revenue increase are allocated to the rate classes with low rates of return on rate base, and smaller relative portions of the overall increase are allocated to the rate classes with high rates of return. In other words, KU is proposing higher percentage increases for rate classes that have low rates of return and lower percentage increases for rate classes that have higher rates of return. KU is proposing rate increases for all rate classes except for Lighting Energy Service. A comparison of the rate of return at current rates and the percentage revenue increase proposed for each rate class is shown below in Table 1:

	Rate of Return on Rate Base		Revenue
Rate Class	**BIP Version**	**LOLP Version**	**Increase**
Residential Service	4.16%	4.36%	5.94%
General Service	9.10%	9.20%	5.06%
All Electric Schools	5.27%	6.77%	5.34%
Primary Service-Secondary	9.61%	9.26%	5.06%
Primary Service-Primary	11.83%	10.70%	4.71%
Time-of-Day Secondary Service	6.42%	6.06%	5.55%
Time-of-Day Primary Service	4.48%	4.05%	6.61%
Retail Transmission Service	4.55%	4.50%	6.71%
Fluctuating Load Service	1.50%	1.24%	7.25%
Lighting Energy Service	9.83%	18.57%	0.00%
Traffic Energy Service	10.02%	11.34%	4.71%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	6.14%
Total All Classes	5.56%	5.56%	6.45%

Table 1

Table 2 shows the same results as Table 1 except that the data is sorted from the highest to the lowest percentage increase:

Rate Class	Rate of Return on Rate Base BIP Version	LOLP Version	Revenue Increase
Fluctuating Load Service	1.50%	1.24%	7.25%
Retail Transmission Service	4.55%	4.50%	6.71%
Time-of-Day Primary Service	4.48%	4.05%	6.61%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	6.14%
Residential Service	4.16%	4.36%	5.94%
Time-of-Day Secondary Service	6.42%	6.06%	5.55%
All Electric Schools	5.27%	6.77%	5.34%
Primary Service-Secondary	9.61%	9.26%	5.06%
General Service	9.10%	9.20%	5.06%
Primary Service-Primary	11.83%	10.70%	4.71%
Traffic Energy Service	10.02%	11.34%	4.71%
Lighting Energy Service	9.83%	18.57%	0.00%
Total All Classes	5.56%	5.56%	6.45%

Table 2

As illustrated in Table 2, the percentage increases allocated to the rate classes are essentially inversely proportional to the class rate of return. In allocating the revenue increase to the classes, one of the Company's objectives was to limit the maximum increase to any class to approximately one percentage point above the overall increase. This results in the class with the lowest rate of return receiving a 7.25 percent increase and the class with the highest rate of return receiving a zero percent increase. The decision was made not to assign an increase for any rate class with a rate of return exceeding 15 percent. All other rate classes with a rate of return under 15 percent were allocated a rate increase within a bandwidth of approximately 1 to 1.75 percentage points of the average increase.

Q. Are there any rate classes that are not shown on the above table?

A. Yes. Residential Time of Day Service (RTOD) is a small rate class currently serving only 25 customers. This rate class was included with Rate RS in the cost of service study. KU is proposing an increase of 5.91 percent for this rate class.

Q. Are classes with the higher rates of return subsidizing classes with low rates of return?

A. Yes, from a cost of service perspective, they are. Of course, cost of service is just one factor that must be considered. Economic factors such as job creation and retention are also important considerations.

Q. Is KU proposing to eliminate all subsidies in this proceeding?

A. No. KU's objective is to eliminate subsidies gradually over time. While KU does want to address the issue of subsidies, the Company proposes to do so in a manner that doesn't create unduly large increases for any one major rate class.

Q. Have you prepared schedules showing the proposed revenue increase for each standard rate schedule?

A. Yes. The revenue increase for each rate class is shown on Schedule M-2.1 of Section 16(8)(m) of the Filing Requirements. The detailed billing calculations for each rate schedule are shown on Schedule M-2.3. The proposed unit charges for each rate schedule are shown on Schedule M-2.3.

B. RESIDENTIAL SERVICE (RS)

Q. Please provide a brief description of Rate RS.

A. Rate RS is the standard rate schedule available to single-family residential service. Approximately 431,000 residential customers are served under this rate schedule.

Rate RS has a two-part rate structure that includes a Basic Service Charge and an Energy Charge.

Q. What are the charges that KU is proposing for Rate RS?

A. KU is proposing to *increase* the Basic Service Charge from $10.75 per month to $22.00 per month. The Company is proposing to *decrease* the energy charge from $0.08870 per kWh to $0.08523 per kWh.

Q. Is the Company proposing any changes in the presentation of the charges for Rate RS?

A. Yes, KU is proposing that the energy charge be broken down into a variable cost component (Variable Energy Charge) and a fixed cost component (Infrastructure Energy Charge). The Variable Energy Charge is $0.03508 per kWh and the Infrastructure Energy Charge is $0.05015 per kWh. These charges would also apply to Volunteer Fire Department Service (Rate VFD).

Q. Why is the Company proposing this change?

A. The purpose of showing the energy charge as consisting of both a variable cost component and a fixed cost component is solely educational and informational at this point in time. The Company wants customers, stakeholders and employees to be aware that two types of costs are included in the energy charge for Rate RS and other rates that have a two-part rate structure consisting of a Basic Service Charge and an Energy Charge. The energy cost component consists of costs, such as fuel expenses and variable operation and maintenance expenses, that vary directly with the kWh usage of customers. The fixed cost component consists of demand-related costs that do not vary directly with energy usage, such as depreciation expenses, return, taxes, and fixed operation and maintenance expenses related to utility infrastructure. It is important for customers, stakeholders and employees to understand that not all costs are automatically reduced when customers use less energy. For example, the fixed costs associated with poles, transformers, conductors, power plants, office buildings, etc., are not automatically reduced when consumers reduce their energy usage. As greater emphasis is placed on distributed generation and energy conservation in our society, it is important for customers, stakeholders and utility employees to understand the distinction between fixed and variable costs.

Q. What is the breakdown of total costs among these three cost components for Rate RS?

A. The following table shows how the cost of providing service to customers under Rate RS is broken down between customer-related fixed costs, demand-related fixed costs, and energy-related variable costs:

Cost Component	Percentage of Cost
Customer-Related Fixed Costs	20.9%
Demand-Related Fixed Costs (Infrastructure Demand Costs)	43.0%
Energy-Related Variable Costs	36.1%

Table 3

Q. How are these costs currently recovered from Rate RS customers?

A. Rate RS, as well as a number of other KU rate schedules that serve smaller commercial and industrial customers (for example Rate GS), are currently structured as a *two-part rate* consisting of a customer charge (Basic Service Charge) and an energy charge. The Basic Service Charge is billed as a flat monthly charge per customer, and the energy charge is a variable charge billed on a cents-per-kWh basis. Under a two-part rate design, all *three cost components* (customer costs, demand costs and energy costs) are recovered through *two rate components* (customer charge and energy charge). Unlike the three- and multi-part rates that are used for KU's larger customers, the two-part rate for Rate RS does not utilize a demand charge. Therefore, demand costs (costs associated with transformers, overhead and underground conductor, transmission lines, and generation capacity) must be recovered through either the customer charge or the energy charge. For Rate RS, all demand costs and a portion of the customer costs are currently being recovered through the energy charge. The following table compares the percentage of costs broken down by component (customer cost, demand cost, and energy cost) to the percentage of recovery through the rate components (customer charge and energy charge):

Component	Percentage of Cost	Rate Design
Customer	20.9%	9.3%
Demand	43.0%	0.0%
Energy	36.1%	90.7%

Table 4

As can be seen from this table, all demand costs and a significant portion of customer costs are currently recovered through a variable energy charge.

Q. What are three- and multi-part rate designs?

A. A *three-part rate* is a rate structure that includes a customer charge, energy charge and demand charge. KU's rate for medium commercial and industrial customers (Rate PS) is a three-part rate consisting of a customer charge, energy charge and demand charge. The rates for large commercial and industrial customers (Rate TODS, TODP, RTS, and FLS) are structured as a *multi-part rate* consisting of a customer charge, energy charge and multi-part demand charge that is unbundled between production fixed cost components and transmission/distribution fixed cost components. The reason that a two-part rate structure traditionally has been used in the industry for residential and small commercial and industrial accounts is that the cost of the metering technology necessary to bill a three- or multi-part rate for small customers has been prohibitive. This is changing in the industry. As utilities install advanced metering technology for all types of customers, it becomes more feasible to use three- or multi-part rates for residential and general service (small commercial and small industrial) customers.

Q. Does recovering fixed customer and demand costs through a variable energy charge create problems?

A. Yes, it certainly does. The Company must install generation, transmission and distribution infrastructure to serve customers. The costs associated with this infrastructure are fixed. As explained earlier, some of these fixed costs are demand-related and are thus related to utility infrastructure that is sized to meet maximum loads that customers place on the system, while other fixed costs are customer-related and are thus related to the number of customers that the utility serves. These fixed costs typically will not change if a customer uses more energy or if a customer uses less energy. For example, once the Company installs a distribution line, transformer, service line, and meter to serve a customer, the operation and maintenance expenses, depreciation expenses, property taxes, interest expenses, and other such costs are not decreased if a customer uses less energy. Once the facilities are installed they are invariant to customer usage and are therefore fixed. If the costs are improperly recovered through a volumetric charge rather than a fixed charge, then when a customer uses less energy these fixed costs will not be recovered from the customer, and those costs must be recovered from other customers. This is particularly problematic if a customer reduces energy consumption by installing distributed generation technology such as solar panels or a wind turbine but falls back on the utility when sunlight is unavailable or when the wind isn't blowing. In those instances, the customer will have reduced its energy usage with distributed generation but will still require the same generation, transmission and distribution capacity to meet its demand requirements. The customer will have reduced the billing of fixed costs collected through the energy charge but will not have caused the utility to reduce its fixed costs. In those instances, the fixed costs are thus shifted to customers who have not installed distributed generation technology.

Q. At this point, has distributed generation created problems for KU?

A. Nothing significant. However, the installation of customer-owned distributed generation is already creating problems with the erosion of fixed cost recovery for utilities in western states, such as New Mexico, Arizona, Nevada, and Colorado. At this point, it is important for KU to be aware of what is going on in other jurisdictions and to begin educating its customers, stakeholders and employees about the kinds of costs that are fixed and those that are variable and thus avoidable. In the short term, only variable costs are avoidable as a result of self-generation and conservation efforts by consumers. But even if distributed generation never becomes a major factor on KU's system, the changes that KU is proposing are still beneficial because the Company is moving toward a more cost-based rate structure. Thus, KU's rates provide for a more fair and equitable recovery of costs from customers.

Q. With the emergence of customer-owned distributed generation, what ratemaking frameworks are other utilities and commissions exploring to ensure

that costs are fairly and equitably recovered from customers?

A. They are looking into a number of options. In a recent rate case in New Mexico for which I was a witness, the commission staff proposed a rate design that would insure that all production, transmission and distribution fixed costs would be recovered fully from customers with distributed generation. Other utilities are considering the implementation of three- and multi-part rates for residential and small commercial and industrial customers. Under some of the approaches being adopted by utilities, residential customers would be billed under a rate that includes one or more types of demand charges; for example, the residential rate could include a demand charge that is billed on the basis of the customer's maximum monthly demand (that recovers transmission and distribution fixed costs) and a demand charge billed on the basis of the customer's demand determined at the time of the utility's system peak (coincident peak demand) (that recovers generation fixed costs.) Ultimately, rates that make use of multi-part rate structures allow utilities to price electric service in a more cost-based manner, thus greatly reducing, if not eliminating, intra-class subsidies.

Some utilities are also considering the use of straight-fixed variable ("SFV") rate designs that would collect all transmission and distribution costs through a monthly customer charge. An SFV rate is a rate design in which all the utility's fixed costs, or fixed transmission and distribution costs, would be recovered through a flat monthly charge, such as a customer charge. SFV rate designs have been used extensively in the natural gas industry to deal with declining usage, downward spiraling margins, and the equitable recovery of fixed costs. An SFV rate design would not only help protect the utility against lost revenue due to energy conservation and the installation of distributed generation but it would also ensure that fixed costs are fairly and reasonably distributed. Only the utility's avoidable costs would be recovered through an energy charge, specifically, the utility's variable energy costs. All fixed costs would be recovered through the customer charge or other fixed charge, thus fully ensuring the fixed costs are inappropriately shifted onto customers that do not implement distributed generation.

Other utilities are proposing revenue decoupling mechanisms to allow the utility to encourage the introduction of behind-the-meter distributed generation technologies without resulting in an erosion of fixed cost recovery. Revenue decoupling is designed to decouple the link between energy usage and the amount of net revenues collected by the utility. It is generally implemented as a rate adjustment mechanism that operates with annual surcharges or surcredits. With decoupling, the annual amount of net revenues, or fixed cost revenues, (total revenues less variable energy expenses) for a rate class would be compared to the fixed-cost revenue requirement determined from the utility's rate case for that rate class, as adjusted to reflect increases or decreases in the number of customers served. If the net revenues collected from the customer class for a 12-month period is less than the fixed-cost revenue requirement for the customer class determined from the rate case (as adjusted for changes in the number of customers served) then a surcharge is calculated based on the deficiency and then applied to kWh sales in a subsequent 12-month period. Likewise, if the net revenues collected from the customer class for a 12-month period are greater than the fixed cost revenue requirement for the customer class determined from the rate case (again, as adjusted for changes in the number of customers served) then a surcredit is calculated based on the excess revenues and applied sales in a subsequent 12-month period. Since decoupling allows the utility to collect net revenues equivalent to the fixed-cost revenue requirement from its last case, the utility would be protected against the loss of revenues due to the adoption of distributed generation technologies by customers. Decoupling and other lost revenue mechanisms have been implemented by several utilities in conjunction with energy conservation and demand-side management programs. Decoupling is often identified as a way to align the interests of the utility and customers in the adoption of energy saving technologies.

Q. Are these options that KU and LG&E should be evaluating?

A. Yes. It is important for the Companies to continue to monitor developments in the industry. But at this point, breaking out the energy charge in the Company's two-part rates into fixed and variable cost components is a good first step toward educating customers, stakeholders and employees about what makes up the cost of providing service to customers.

Q. What is the basis for the proposed increase in the Basic Service Charge for Rate RS?

A. The Company is proposing a cost-based Basic Service Charge that reflects the customer-related costs from the Company's cost of service study. As will be explained in greater detail in the portion of my testimony dealing with the cost of service study, the methodology that is used to classify costs as customer related corresponds to the methodology that has been accepted by the Commission in the past. The methodology for classifying costs as customer-related also corresponds to one of the standard methodologies set forth in the *Electric Utility Cost Allocation Manual* published by the National Association of Utility Regulatory Commissioners ("NARUC").

Q. Have you prepared an exhibit showing the calculation of the cost components for Rate RS?

A. Yes. Exhibit WSS-2 shows the calculation of the unit customer cost, demand related cost, and energy costs from the BIP version of the cost of service study. From this calculation, the customer cost is $23.93 per customer per month; the demand-related cost is $0.04849/kWh; and the energy cost is $0.03508/kWh. In the proposed rate, KU is proposing a Basic Service Charge of $22.00 which is below the unit cost from the cost of service study. The difference is recovered through the Infrastructure Energy Charge which KU is proposing to be $0.05015/kWh. The Company is proposing a Variable Energy Charge of $0.03508/kWh, which is the same as calculated from the cost of service study.

Q. Why is the Basic Service Charge rounded?

A. The Basic Service Charge is rounded to keep the charge as simple and easy to use as possible. The Companies are also proposing that the Basic Service Charge be the same for both KU and LG&E. The Companies are proposing a residential customer charge that represents the lowest rate that can be cost supported for KU and LG&E.

Because LG&E's customer cost is equal to $22.04 per month and KU's is equal to $23.93 per month, a customer charge of $22.00 was selected for the Companies because it reflected the lowest of the two unit costs after giving effect to rounding.

Q. Please explain the costs that are recovered through the Basic Service Charge.

A. The Basic Service Charge recovers the minimum system that each customer must have in place to access the electric grid. The customer charge also recovers the cost of operating and maintaining this minimum system as well as other costs not related to customer usage, such as meter reading, billing and customer service costs. The minimum system comprises the meter, service drop from the transformer, the transformer, the minimum size of wire, and poles extending to the distribution substation that is necessary to provide a customer with access to the electric grid. Once the cost of this minimum system is determined using the zero-intercept methodology (discussed later in my testimony), it can be allocated to each customer.

Q. What other costs need to be recovered from customers?

A. Customers often need more equipment than the minimum system in order to receive adequate service. The cost of this equipment above the minimum is related to the customer's usage level and is a demand-related fixed cost that is recovered through either a demand or energy charge. A cost of service study is performed for the purpose of allocating costs as accurately as possible based on cost causation. In a cost of service study, it is important to distinguish the distribution system costs related to demand from the distribution system costs that are related to the minimum system which are not related to demand, as discussed in the NARUC <u>Electric Utility</u>

Cost Allocation Manual. As discussed earlier, the Company must install the minimum amount of equipment to provide customers with access to the electric grid. This minimum amount of equipment is not related to the volume of electricity used by the customer, and each customer must have that minimum amount of equipment in place to obtain electric service. These non-volumetric fixed distribution costs are associated with serving the customer and therefore should be borne by the customer through a fixed customer charge regardless of usage. The remainder of the distribution costs, which are related to installed capacity, are classified as demand-related and are collected through a kWh energy charge for Rate RS or through a kW charge for customer classes billed under a three- or multi-part rate that has a demand charge. This split of distribution system costs between volumetric and fixed assures that customers only have to pay for what they are actually using, namely the basic minimum system that all customers require plus as much additional equipment as required to meet their needs.

Q. Does the current Basic Service Charge of $10.75 recover all KU's customer-related costs for Rate RS?

A. No. The current Basic Charge of $10.75 per customer per month does not recover all of the customer-related fixed costs of $23.93. Based on Exhibit WSS-2, there are $13.18 in customer-related fixed costs per customer per month (calculated as $23.93 - $10.75 = $13.18) that are not being collected through the Basic Service Charge. When this under-recovery of $13.18 per customer per month is multiplied by the billing units of 5,167,560 customer months for Rate RS during the test year, the result is $68,108,441 in fixed customer-related costs that are not being recovered through the Basic Service Charge under the current rate design. When these customer charge fixed costs are recovered through the Energy Charge instead, the result is about 1.1 cents per kWh of non-volumetric fixed cost collected through the Energy Charge (calculated as $68,108,441/ 6,091,291,833 kWh = $0.011/kWh). Thus, the current Basic Service Charge is $13.18 per customer per month too low and the Energy Charge is 1.1 cents per kWh too high based on data from the cost of service study. This recovery of non-volumetric fixed costs through the energy charge assessed on a kWh basis results in intra-class subsidies and in unrecovered fixed costs if kWh usage declines due to energy efficiency, conservation or mild weather.

Q. Will KU's proposed residential rate help to eliminate subsidies?

A. Yes. There are two types of subsidies that need to be considered – inter-class subsidies and intra-class subsidies. The term "*inter-class subsidies*" refers to subsidies that are provided from or to one class of customers to or from another class of customers, and the "*intra-class subsidies*" refers to subsidies that are provided from or to customers within the same rate class. KU's proposed rates are designed to make progress towards reducing both *inter-* and *intra-class* rate subsidies. As will be discussed, the apportionment of the total revenue increase to the customers was developed in such a manner as to provide a reduction in *inter-class subsidies*.

The rate making principle to follow to avoid *intra-class subsidies* is that fixed costs should be recovered through fixed charges (such as the customer charge and demand charge), and variable costs should be recovered through variable charges (such as the energy charge and the fuel adjustment charge). If fixed costs are recovered through variable charges, such as the energy charge assessed on a kWh basis, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of the utility's fixed costs, while customers using less energy than the average customer in the class are paying less than their fair share of the utility's fixed costs. These fixed costs should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is not the correct cost driver for collecting fixed costs.

The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. In order to eliminate this source of intra-class subsidies, KU proposes a rate design that more closely follows the ratemaking principle of recovering fixed costs through fixed charges and variable costs through variable charges than does its current rate design.

Increasing the Basic Service Charge will eliminate subsidies by bringing the charges toward the actual cost of providing service. Increasing the Basic Service Charge from $10.75 to $22.00 will eliminate subsidies that high usage customers are currently providing low usage customers.

C. RESIDENTIAL TIME-OF-DAY ENERGY AND DEMAND SERVICES

Q. Please provide a brief description of KU's residential time-of-day rates.

A. KU offers two time-of-day rates, RTOD-Energy and RTOD-Demand. Rate RTOD-Energy is a time-of-day rate that includes a time differentiated energy charge. Under the rate, customers are charged a significantly lower energy charge for off-peak usage. There are approximately 25 customers currently taking service under RTOD-Energy. The Company is not proposing any structural changes to Rate RTOD-Energy.

Rate RTOD-Demand is a time-of-day rate that includes a flat energy charge but a time differentiated demand charge. There are currently no customers taking service under RTOD-Demand. KU is proposing structural changes to Rate RTOD-Demand to more accurately reflect costs and thus encourage customers to sign up for the rate.

Q. What are the charges that KU is proposing for Rate RTOD-Energy?

A. KU is proposing to *increase* the Basic Service Charge from $10.75 per month to $22.00 per month and to *decrease* the off-peak energy charge from $0.05740 per kWh to $0.05266 per kWh. The Company is proposing to increase the Basic Service Charge to the same level as being proposed for Rate RS. The off-peak energy charge is being reduced to a level that yields a revenue increase for Rate RTOD-Energy that is approximately equal to the percentage increase for Rate RS.

Q. What structural changes is KU proposing for Rate RTOD-Demand?

A. KU is proposing to eliminate the off-peak demand charge and replace it with a base demand charge that is applied to the customer's maximum usage whenever it occurs. This is the same structure that has been used for several years for KU's large customer rates and seems to operate effectively. Using a base demand charge rather than an off-peak demand charge prevents customers from being penalized for improvements in load factor. KU is proposing to *increase* the Basic Service Charge from $10.75 per month to $22.00 per month and to *decrease* the off-peak energy charge from $0.04370 per kWh to $0.03508 per kWh. The Company is proposing to replace the demand charge for off peak hours of $3.70 per kW with a demand charge for all hours of $3.44 per kW, and to decrease the demand charge for on peak hours from $13.05 per kW to $7.87 per kW.

D. GENERAL SERVICE (GS) AND ALL ELECTRIC SCHOOLS SERVICE (AES)

Q. Please provide a brief description of Rate GS.

A. Rate GS is the standard rate schedule available to small commercial and industrial customers served at secondary voltages (available voltages *less than* 2,400/4,160Y volts). The rate schedule is limited to customers whose 12-month average monthly demands do not exceed 50 kW. Approximately 83,000 small commercial and industrial customers are served under this rate schedule. Rate GS has a two-part rate structure that includes a Basic Service Charge and an Energy Charge.

Q. What are the charges that KU is proposing for Rate GS?

A. KU is proposing to increase the Basic Service Charge for Rate GS from $25.00 per month to $31.50 per month for single-phase service and from $40.00 to $50.40 per month for three-phase service. The Company is proposing to increase the energy charge from $0.10426 per kWh to $0.10685 per kWh. As with Rate RS, the energy charge for Rate GS will be broken down into Variable Energy Charge and

Infrastructure Energy Charge. The Variable Energy Charge is $0.03548 per kWh and the Infrastructure Energy Charge is $0.07137 per kWh.

Q. Please provide a brief description of Rate AES.

A. Rate AES is a rate generally available for school buildings, although the rate is closed to new customers and is limited to customers that were qualified for, and being served on, Rate AES as of July 1, 2011. There are approximately 590 schools taking service under Rate AES. KU is proposing to increase the Basic Service Charge for Rate AES from $25.00 per month to $85.00 per month for single-phase service and from $40.00 to $140.00 per month for three-phase service. The Company is proposing to increase the energy charge from $0.08369 per kWh to $0.08519 per kWh. As with Rates RS and GS, the energy charge for Rate AES will be broken down into Variable Energy Charge and Infrastructure Energy Charge. The Variable Energy Charge is $0.03523 per kWh and the Infrastructure Energy Charge is $0.04996 per kWh.

E. POWER SERVICE (PS)

Q. What are the charges that KU is proposing for PS?

A. PS is a rate available for large commercial and industrial customers served at secondary voltages (available voltages *less than* 2,400/4,160Y volts) whose 12-month average loads exceed 50 kW but do not exceed 250 kW and for large commercial and industrial customers served at primary voltages (2,400/4,160Y volts, 7,200/12,470Y volts, or 34,500 volts) whose 12-month average do not exceed 250 kW. KU is not proposing an increase to Basic Service Charge for customers served at secondary voltages. Therefore, the Basic Service will remain at $90 per customer per month for secondary voltage customers. The Company is proposing to increase the Basic Service Charge from $200.00 to $240.00 per customer per month for customers served at primary voltages. The Company is not proposing to change the Energy Charge for either secondary voltage customers. Thus, the energy charge will remain at $0.03572 per kWh for secondary voltage service. KU is proposing to increase the energy charge from $0.03446 to $0.03472 per kWh for primary voltage service. For secondary voltage service, the Company is proposing to increase the Summer Demand Charge from $19.05 to $20.71/kW/Mo and to increase the Winter Demand Charge from $16.95 to $18.43/kW/Mo. For primary voltage service, the Company is proposing to increase the Summer Demand Charge from $19.51 to $20.78/kW/Mo and to increase the Winter Demand Charge from $17.41 to $18.54/kW/Mo.

Q. **In its Order in Case No. 2015-00417 dated June 29, 2016, the Commission ordered KU to include in its next application for a general adjustment in rates testimony in support of the monthly billing demand provisions of Rate PS. Will you be the witness addressing this issue?**

A. Yes.

Q. **How is the billing demand determined under Rate PS?**

A. For Rate PS, the monthly billing demand is determined as the greater of the following:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or

b) a minimum of 50% of the highest measured demand in the preceding eleven (11) monthly billing periods, or

c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Q. Is this a standard provision in the electric utility industry?

A. Yes. It is common for utilities to determine billing demands on the basis of a minimum demand (as in provisions (a) and (c) as shown above) or based on a percentage of the highest demands during a previous 11-month period (as in provision (b) as shown above) or both. Determining billing demands on the basis of a percentage of the highest demand during a previous 11-month or other period is referred to as a "demand ratchet" in the electric utility industry, and is a standard practice in the industry. In a standard treatise on electric utility ratemaking, Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies* (CRC Press: 2009), the author states:

> A *demand ratchet* processes a customer's metered maximum demand for the prior eleven months by applying a specified percentage to those demands in all or a portion of those months and then selects the highest resulting calculated demand as the current month's billing demand – if it exceeds the current month's maximum demand. (*Id.*, at pp. 312.)

Not only are demand ratchets standard provisions in the industry, but the use of a demand ratchet percentage of 50% or greater is also common.

Q. Do other utilities in Kentucky, Indiana, and Ohio have demand ratchets?

A. Yes. The medium and large power tariffs of the major utilities in the region use some form of a demand ratchet. Below is a summary of the ratchets used by investor-owned utilities in Kentucky, Indiana, and Ohio:

i) For Kentucky Power Company's Medium General Service Tariff M.G.S., the monthly billing demand is the maximum of (a) the minimum billing demand of 6 kW or (b) 60% of the greater of (1) the customer's contract capacity in excess of 100 kW or (2) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW.

ii) For Duke Energy Kentucky's and Duke Energy Ohio's Rate DS Service at Secondary Voltage, the billing demand is the higher of (a) 85% of the highest monthly kW demand established in the summer period and effective for the next succeeding 11 months or (b) 1 kW for single phase secondary voltage service and 5 kW for three-phase secondary voltage service.

iii) For Indianapolis Power & Light Company's Rate PL Primary Service, the billing demand cannot be less than 60% of the highest billing demand that has been established in any of the immediately preceding 11 months and in no case less than 500 kW.

iv) For Indiana Michigan Power Company, the monthly billing demand in Indiana cannot be less than 60% of the customer's highest previously established monthly billing demand during the past 11 months, or 100 kVA.

v) For Ohio Edison, the monthly billing demand is the maximum of 1) the measured demand during the month; 2) 5 kW; or 3) the contract demand (where the contract demand is 60% of the customer's expected, typical monthly peak load.)

Q. Is the ratchet provision in KU's Rate PS in line with these other utilities?

A. Yes. All of these utilities except Duke Energy Kentucky and Duke Energy Ohio have a 60% ratchet provision. Duke Energy Kentucky and Duke Energy Ohio have an even higher ratchet percentage of 85%, but the ratchet is only applied to demands metered during the summer months. The ratchet percentage used in KU's Rate PS is lower than these other utilities.

Q. What is the justification for including a demand ratchet in a large power tariff such as Rate PS?

A. A utility must install distribution, transmission, and generation facilities to serve a customer's demand. Just because a customer's demand is not always at the maximum level does not mean that the fixed costs of the facilities installed to meet the customer's maximum demand will disappear. The fixed costs of the facilities installed to meet a customer's maximum demand will be incurred even when the customer has a lower demand. In the case of localized facilities, such as primary and secondary distribution lines, transformers, substations, and transmission facilities, the utility must install sufficient capacity to meet the customer's maximum demand, whenever the demand occurs. Therefore, a utility's transmission and distribution fixed costs are correlated to the customers' maximum demands, not their average monthly demands. Generation fixed costs are correlated to customer demands at the time of the system peak. For most but not all customers, the customer's maximum demands occur near the system peak. For system peak demands, which drive the cost of generation fixed assets, customer load diversity has an effect on the generation requirements that individual customer demands place on the system. Therefore, while a 100% ratchet percentage is justified for the recovery of transmission and distribution fixed costs, a lower ratchet could possibly be justified for the recovery of generation fixed costs. For this reason, in an unbundled rate environment in which generation fixed costs are billed separately from transmission and distribution fixed costs, a 100% ratchet percentage would be justified for the transmission and distribution component, while a lower percentage, such as 50%, would typically be used for the generation fixed cost component of the rate. With a bundled rate, such as KU's Rate PS, in which generation, transmission and distribution fixed costs are recovered through a single demand charge, it is not uncommon to see demand ratchets for a bundled demand charge in the 50 to 90% range.

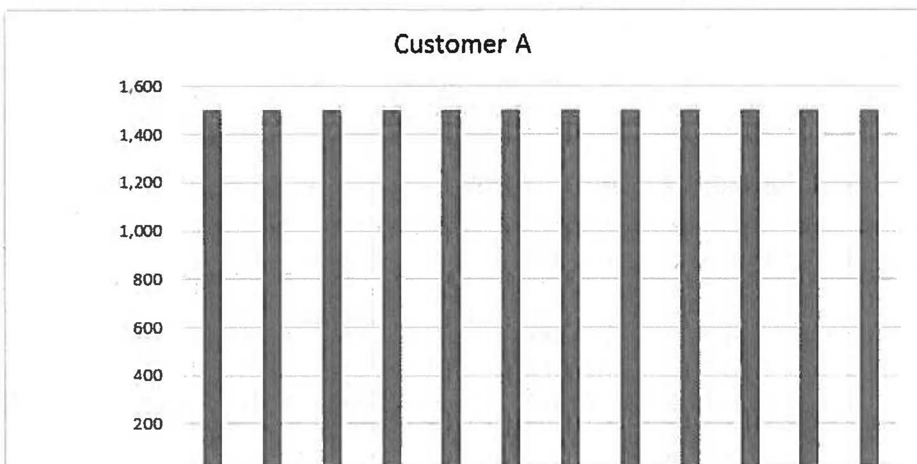
Q. Do demand ratchets more accurately reflect the actual cost of providing service?

A. Yes, in general they do. Because demand-related fixed costs do not disappear when customers have lower demands during the year, demand ratchets ensure that customers with month-to-month fluctuations in their demand pay an appropriate share of fixed costs. Without demand ratchets, customers with demands that fluctuate from month to month end up being subsidized by customers with steady demands.

Q. Can you provide an example that shows how, without a demand ratchet,

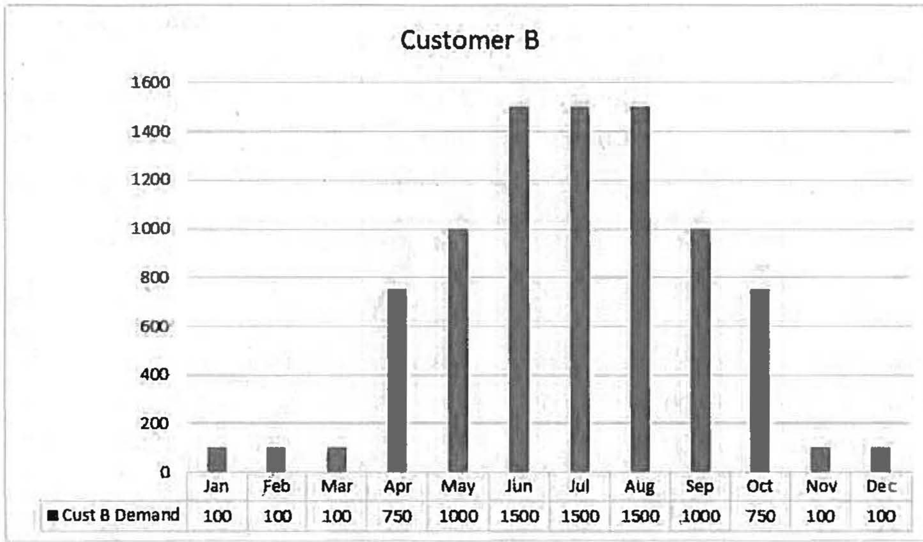
customers with steady demands end up subsidizing customers with fluctuating demands?

A. Yes. Consider two customers – Customer A and Customer B – both with a maximum demand of 1,500 kW during the year. In this example, Customer A has a steady demand of 1,500 kW every month. Customer B has a demand of 1,500 kW that only occurs during the summer peak months, but during the non-summer months Customer B's demands are significantly lower. For purposes of this example, we will assume that both customers' summer demands are coincident with the summer system peak. This is a simplifying but not unrealistic assumption. The following two graphs show the monthly demands for Customer A and Customer B.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cust A Demand	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500

Graph 1



Graph 2

In this example, if there are no significant topographical differences between serving the two customers, the fixed generation, transmission and distribution costs would be essentially the same for both customers. Both customers have a 1,500 kW demand coincident with the summer system peak; therefore, the generation fixed costs necessary to serve both customers would be the same. Both customers have a maximum non-coincident demand of 1,500 kW; therefore, the transmission and distribution delivery costs would be the same for both customers. Therefore, in this example, the fixed generation, transmission and distribution costs are the same to serve both customers. Yet, even though it costs the same to serve both customers, without a demand ratchet, the demand charge revenues collected from the two customers are starkly different. The following table shows the demand charge revenue that would be collected from the two customers under the current Rate PS Secondary demand charges without a ratchet:

	Customer A			Customer B		
Month	kW Demand	Demand Charge	Demand Charge Revenue	kW Demand	Demand Charge	Demand Charge Revenue
Jan	1,500	16.95	$ 25,425	100	16.95	$ 1,695
Feb	1,500	16.95	25,425	100	16.95	1,695
Mar	1,500	16.95	25,425	100	16.95	1,695
Apr	1,500	16.95	25,425	750	16.95	12,713
May	1,500	19.05	28,575	1000	19.05	19,050
Jun	1,500	19.05	28,575	1500	19.05	28,575
Jul	1,500	19.05	28,575	1500	19.05	28,575
Aug	1,500	19.05	28,575	1500	19.05	28,575
Sep	1,500	19.05	28,575	1000	19.05	19,050
Oct	1,500	16.95	25,425	750	16.95	12,713
Nov	1,500	16.95	25,425	100	16.95	1,695
Dec	1,500	16.95	25,425	100	16.95	1,695
Total			$ 320,850			$ 157,725

Table 6

As can be seen from the table, KU would collect less than half the revenue in demand charges from Customer B than from Customer A, even though the fixed costs associated with serving the two customers are the same. Without a ratchet Customer A would be overpaying and Customer B would be underpaying for service. In other words, Customer A would be subsidizing Customer B.

Q. What happens in the example if the Company's current demand ratchet for Rate PS is used?

A. Under the demand ratchet for Rate PS, the billing demand cannot fall below 50% of the customer's monthly demands during the preceding 11 months. If the same load pattern used in the example reoccurs year after year, then Customer B's billing demand could not fall below 750 kW (1,500 x 50% = 750 kW). Of course, Customer

A's billing demand could not fall below 750 kW either, but in this example Customer A's demand is a constant 1,500 kW and thus Customer A is unaffected by the demand ratchet. The table below shows the demand charge revenue that would be collected from the two customers under the current Rate PS demand charges with the current ratchet:

	Customer A			Customer B		
Month	kW Demand	Demand Charge	Demand Charge Revenue	kW Demand	Demand Charge	Demand Charge Revenue
Jan	1,500	16.95	$ 25,425	750	16.95	$ 12,713
Feb	1,500	16.95	25,425	750	16.95	12,713
Mar	1,500	16.95	25,425	750	16.95	12,713
Apr	1,500	16.95	25,425	750	16.95	12,713
May	1,500	19.05	28,575	1000	19.05	19,050
Jun	1,500	19.05	28,575	1500	19.05	28,575
Jul	1,500	19.05	28,575	1500	19.05	28,575
Aug	1,500	19.05	28,575	1500	19.05	28,575
Sep	1,500	19.05	28,575	1000	19.05	19,050
Oct	1,500	16.95	25,425	750	16.95	12,713
Nov	1,500	16.95	25,425	750	16.95	12,713
Dec	1,500	16.95	25,425	750	16.95	12,713
Total			$ 320,850			$212,813

Table 7

As can be seen, the demand ratchet in Rate PS significantly reduces the subsidies received by Customer B. In this example, the subsidies still exist but they are reduced.

Q. **Would it be possible to eliminate all fixed-cost subsidies?**

A. In this idealized example it would be possible to eliminate all subsidies. This can be done by increasing the ratchet percentage to 100%. If a 100% demand ratchet is applied, Customer B's billing demand would be 1,500 kW each month (100% x 1,500 kW = 1,500 kW). Again, Customer A's billing demands would be unchanged. With a 100% ratchet, the demand billings would be the same for both customers, as illustrated in the following table:

	Customer A			Customer B		
Month	kW Demand	Demand Charge	Demand Charge Revenue	kW Demand	Demand Charge	Demand Charge Revenue
Jan	1,500	16.95	$ 25,425	1500	16.95	$ 25,425
Feb	1,500	16.95	25,425	1500	16.95	25,425
Mar	1,500	16.95	25,425	1500	16.95	25,425
Apr	1,500	16.95	25,425	1500	16.95	25,425
May	1,500	19.05	28,575	1500	19.05	28,575
Jun	1,500	19.05	28,575	1500	19.05	28,575
Jul	1,500	19.05	28,575	1500	19.05	28,575
Aug	1,500	19.05	28,575	1500	19.05	28,575
Sep	1,500	19.05	28,575	1500	19.05	28,575
Oct	1,500	16.95	25,425	1500	16.95	25,425
Nov	1,500	16.95	25,425	1500	16.95	25,425
Dec	1,500	16.95	25,425	1500	16.95	25,425
Total			**$ 320,850**			**$ 320,850**

Table 8

Q. If a 100% percent demand ratchet would eliminate all of the subsidies in the example, then why isn't KU proposing to use a 100% demand ratchet percentage?

A. As mentioned earlier, the example is somewhat idealized. Specifically, it was assumed that both customers' maximum demands occur at the time of the system peak. This means that the cost of the generation capacity installed to serve both customers would be the same. Not all customers with a load pattern that fluctuates like Customer B will have a maximum demand that occurs at the time of the Companies' system peak. Some low-load factor customers will have a maximum demand that coincides with the system peak and others may not. The relationship between a customer's demand at the time of the system peak and the customer's maximum demand is referred to as the coincidence factor. Coincidence factors for commercial and industrial customers during a month will typically range from 50% to 100%. Because coincidence factors are on average less than 100% it is reasonable to use a demand ratchet for generation fixed costs that is less than 100%. This is the reason that demand ratchets for generation fixed costs are typically between 50% to 90% for rates that are not billed based on a coincident peak demand.

Q. Do demand ratchets encourage customers to use power more efficiently?

A. Yes. Demand ratchets encourage customers to manage their peak demands and purchase energy at a more constant rate. If a customer avoids monthly spikes in its demands, then the customer can avoid the application of the ratchet. Therefore, a ratchet provides an incentive for customers to maintain more steady demands, without month-to-month load fluctuations, which will result in a lower average cost of providing service. Because a utility must install capacity to meet spikes in a customer's demands, if a customer avoids demand spikes the utility can then install less distribution, transmission and generation capacity to serve the customer's load. Demand ratchets induce customers to use power more efficiently and allow demand rates to send a better price signal.

F. LARGE CUSTOMER RATES (TODS, TODP, RTS, FLS)

Q. What are the standard large customer rates offered by KU?

A. KU offers four standard rates for large commercial and industrial customers: Time-of-Day Secondary Service (TODS), Time-of-Day Primary Service (TODP), Retail Transmission Service (RTS), and Fluctuating Load Service (FLS). TODS is available to customers served at secondary voltages (available voltages *less than* 2,400/4,160Y volts) with average demands between 250 kW to 5,000 kW. TODP is available to customers served at primary voltages (2,400/4,160Y volts, 7,200/12,470Y volts, or 34,500 volts) with average demands greater than 250 kVA. RTS is available to customers served at transmission voltages (69,000 volts or higher) with average demands greater than 250 kVA. FLS is available to customers served at primary or transmission voltage whose demands are 20,000 kW or greater. Customers with demands of 20,000 kW or greater whose loads either increase or decrease 20 MVA or more per minute or whose load either increase or decrease 70 MVA or more in ten minutes, when any such increases or decreases occur more than once during any hour of the month, are required to take service under FLS. The proposed charges for TODS, TODP, RTS, and FLS are shown on pages 9, 10, 11, and 12, respectively, of Schedule M-2.3 of the Filing Requirements.

Q. Do all of these rate schedules have the same basic rate structure?

A. Yes. All four of these rates have a rate structure consisting of a Basic Service Charge, an Energy Charge, and a Maximum Load Charge comprising a Peak Demand Charge, an Intermediate Demand Charge, and a Base Demand Charge. For example, the unit charges for TODS are ***currently*** as follows:

Basic Service Charge	$200.00 per customer
Energy Charge	$0.03527 per kWh
Maximum Load Charge:	
Peak Demand Charge	$6.13/kW/Mo.
Intermediate Demand Charge	$4.53/kW/Mo.
Base Demand Charge	$5.20/kW/Mo.

The Peak Demand Charge applies to billing demands (maximum demands) that occur during the weekday hours ("Peak Demand Period") from 1:00 PM to 7:00 PM during the summer months of May through September (summer peak months") and during the weekday hours from 6:00 AM to 12:00 Noon during winter months of October through April (winter peak months). The Intermediate Demand Charge applies to billing demands that occur during the weekday hours ("Intermediate Demand Period") from 10:00 AM to 10:00 PM during the summer peak months and from 6:00 AM to 10:00 PM during the winter peak months. The Base Demand Charge applies to the billing demands that occur at any time during the month.

Q. Is there a cost basis for this rate structure?

A. Yes. KU and LG&E must install sufficient generation resources to meet its peak demands. Peak demand conditions occur during the summer peak months and the winter peak months. Furthermore, peak conditions occur during hours between 6:00 AM in the morning and 10:00 PM at night, but varying by season. KU and LG&E must also install sufficient transmission and distribution facilities to deliver the power to the individual customers, no matter when they need power, whether it is during the peak or intermediate period or otherwise. Over the years, the Companies have structured the Peak Demand Charge and the Intermediate Demand Charge so that these charges would essentially provide recovery of generation fixed costs. The Base Demand Charge was structured so that the charge would basically provide recovery of transmission and distribution demand-related costs. (The structure was initially developed by LG&E and included only a peak and base charge, but was eventually adopted by KU and modified to include an intermediate charge to give customers greater opportunities to control their demands and reduce their demand costs.) Therefore, the Maximum Load Charge was, and is, essentially unbundled between generation fixed costs, which are recovered through the Peak and Intermediate Demand Charges, and transmission and distribution demand-related fixed costs, which are recovered through the Base Demand Charge.

Q. How are the billing demands determined?

A. The billing demands for the Peak and Intermediate Demand Charges are determined as the greater of (a) the maximum measured load during the Peak or Intermediate Demand Periods, or (b) 50% of the highest measured demand for the Peak or Intermediate Demand Periods during the preceding 11 monthly billing periods. This means that a 50% demand ratchet applies to the Peak and Intermediate Demand Charges. The billing demands for the Base Demand Charge is determined as the greater of (a) the maximum measured load during the month (i.e., all hours of the months), (b) 75% of the highest measured demand determined the same way in the preceding 11 monthly billing periods, or (c) 75% of the contract capacity based on the customer's maximum load. This means that a 75% demand ratchet applies to the Base Demand Charge. A higher ratchet was implemented for the Base Demand Charge because the charge was designed to recover transmission and distribution demand-related costs which must be adequately sized to meet the customer's maximum demand whenever the demand occurs.

Q. What changes is KU proposing to the rate structure?

A. KU proposes to keep the same basic rate structure but to increase the demand ratchet for the Base Demand Charge to 100%. The Company is not proposing to change the demand ratchets for the Peak and Intermediate Charges at this time.

Q. Why is KU proposing this change?

A. The modification to the demand ratchets for the large customer rates is being proposed in conjunction with the elimination of the Company's standard rider for Supplemental or Standby Service (Rider SS). The Company has concluded that Rider SS is not adequate in light of fundamental changes that are taking place in the electric utility industry. Rider SS is available to customers who are regularly supplied with electric energy from generating facilities (distributed generation) owned by the customer and who desire to contract with KU for reserve, breakdown, supplemental or standby service. Fundamental changes are taking place in the electric utility industry whereby more customers are installing distributed generation to meet their power needs and falling back on the utility to supply power when their facilities are not operating. In some jurisdictions, there has been a surge in the installation of customer-owned renewable distributed generation such as solar generation or wind generation. In general, utilities are supportive of these initiatives as long as the utility's other customers are not subsidizing customers that install distributed generation facilities. Therefore, it is important for utilities to have a rate structure that prevents the subsidization of distributed generation by customers who have chosen not to install distributed generation.

It is also important for a utility to implement rates that allow the utility to recover the appropriate amount of fixed costs associated with serving customers who have installed distributed generation facilities but who want to rely on the utility to provide generation, transmission and distribution service when the distributed generation facilities are not operating. But KU also wants to offer a rate design that provides reasonable cost recovery while not discriminating against customers who install distributed generation and that isn't excessively harsh or onerous to customers who install distributed generation but want backup service.

Q. Why is the current standby rate inadequate?

A. In addition to the administrative problems with the rider that are addressed in the Direct Testimony of Robert M. Conroy, there has generally been an unwillingness on the part of customers with distributed generation to sign up under the rider because it is viewed as "too harsh" or "too onerous". Rider SS, which is a rider that would generally be applicable to customers served under Rates PS, TODS, TODP, RTS, or FLS, requires a standby customer to establish a contract demand for its entire load. The customer would then be billed a minimum demand charge that is the greater of (1) the customer's total demand charge billed under the customer's primary rate schedule (PS, TODS, TODP, RTS, or FLS), or (2) the demand charge calculated by applying the demand charges set forth in Rider SS to the customer's contact demand. Currently, the demand charges set forth in Rider SS are as follows:

Secondary Voltage:	$12.84 per kW (or kVA) per month
Primary Voltage:	$11.63 per kW (or kVA) per month
Transmission Voltage:	$10.58 per kW (or kVA) per month

These charges were designed to provide full recovery of all production, transmission, and distribution fixed costs. Therefore, for a customer who has installed its own distributed generation facilities, the customer will have paid for its own generation facilities plus the full fixed costs per kW (or kVA) of KU's generation facilities on a monthly basis. From the customer's perspective, under this arrangement the customer will view this as paying for the cost of generation assets twice.

Q. But if the utility is standing ready to provide generation backup service to customers who have installed their own generation, then shouldn't the customer pay a portion of the fixed costs?

A. Yes, they should. The challenge, though, is determining the appropriate level of fixed costs that the customer should pay. The amount that a distributed generator should pay largely depends on the operating characteristics of the distributed generation facilities that are installed. In all cases, a standby customer should pay for all of the transmission and distribution plant installed to serve the customer's maximum demand. As discussed earlier in the portion of my testimony addressing the demand ratchet for Rate PS, sufficient transmission and distribution capacity needs to be installed to deliver power to the customer whenever the customer needs it. For a customer who has installed distributed generation facilities, the utility must have transmission and distribution capacity to deliver sufficient power to meet the customer's load requirements whenever the customer's distributed generation facilities aren't operating. But for generation capacity, the cost of backing up the customer depends on the operating characteristics of the customer's generating facilities. For example, if the customer has installed solar generation, then the utility would be called upon to provide backup power whenever there isn't sufficient sunlight to energize the solar panels, which is likely to occur during periods when the utility is experiencing peak load conditions, such as during a winter system peak which typically occurs during nighttime hours. Likewise, if the customer has installed wind generation, then the utility would be called upon to provide backup power whenever the wind isn't blowing, which is also likely to occur during summer and winter system peak load conditions. Therefore, for these types of distributed generation facilities, it is highly likely that the utility would be called upon to provide backup power during time periods when the utility is experiencing peak load conditions. On the other hand, if the customer has installed a coal- or gas-fired generating facility that operates basically continuously at a low forced outage rate, then it is less likely that the utility would be called upon to provide generation backup power during peak load conditions. Therefore, it would, in general, be less costly to provide generation backup service to a customer who has a generating facility that is operated 24 hours per day, seven days per week, but with a random forced outage rate than to provide generation backup service to a customer whose generating facility is subject to wind conditions and available sunlight.

Q. How will the costs of providing backup service be addressed if Rider SS is eliminated?

A. Under KU's proposal, a customer with distributed generation facilities who relies on KU to provide backup service to its generating facilities would be served on the same rate as any other customer. Therefore, the Company will not discriminate between a customer who has distributed generation facilities and any other customer with similar fluctuating load requirements. If a customer with distributed generation meets the load requirements for one of the Company's standard rate schedules, then the customer will be served under that rate schedule. However, this policy necessitates a change in the demand ratchet for Rates TODS, TODP, RTS, and FLS.

Q. Please explain how serving standby customers under TODS, TODP, RTS, and FLS and changing the ratchet will help provide proper recovery of fixed generation, transmission, and distribution demand-related costs.

A. As explained earlier, generation fixed costs are essentially recovered through the Peak and Intermediate Demand Charges. A 50% demand ratchet is applied in determining the billing demand for these rate components. Importantly, the billing demands are based on measured demands during the Peak and Intermediate Billing Periods. Therefore, if a standby or other customer has a demand that occurs during the peak and intermediate hours (and most customers do), then the Peak and Intermediate Demand Charges will apply to those demands. But if the customer's demand occurs outside of the Peak and Intermediate Billing Periods, then there will be no measured demands during those periods and the Peak and Intermediate Demand Charges will not apply.

Furthermore, the 50% ratchet will be applied based on the maximum demands that have occurred during the preceding 11 months. ***KU is not proposing to change the ratchet percentages applicable to the Peak and Intermediate Demand Charges at this time.*** The structure for determining the billing demand allows the Company to recover at least 50% of a maximum demand that occurred during the peak and intermediate periods for the current and preceding 11 months. This demand ratchet therefore provides recovery of at least 50% of the annual fixed generation costs that the Company has incurred to supply generation capacity to the customer. At this point, the Company believes that the 50% demand ratchet, along with the change to the proposed ratchet for the Base Demand Charge, strikes a reasonable balance *between* (i) providing a pricing structure for recovering a reasonable portion of the annual fixed generation costs incurred to provide service to standby customers and to customers with intermittent loads that fluctuate from month to month *and* (ii) offering a pricing structure that isn't unduly harsh or onerous to standby or customers with intermittent loads. It should be kept in mind that the two components that provide recovery of generation fixed costs – the Peak and Intermediate Demand Charges – represent most of the total demand charges billed under Rates TODS, TODP, RTS, and FLS. Under KU's current rates, the peak and intermediate demand charges represent from approximately 67% to 75% of the total demand charges. (For example, by calculating a simple percentage of the peak and intermediate demand charges to the total of the peak, intermediate and base demand charges for Rate TODS, the percentage is 67% [($4.53 + $6.13) ÷ ($4.53 + $6.13 + $5.20) = 67%]. For Rate TODP, the percentage to the total is 75% [($4.39 + $5.89) ÷ ($5.89 + $4.39 + $3.34) = 75%]. Therefore, peak and intermediate demand charges, which represent most of the demand charges for these rate schedules, will be unaffected by the proposed change in the ratchet.

For transmission and distribution costs, it is important to increase the ratchet percentage to provide assurance that the fixed costs of the transmission and distribution facilities installed to deliver power to customers any time they need the power are appropriately recovered from standby customers and from customers with large month-to-month fluctuations in their loads. As explained in the portion of my testimony dealing with the demand ratchets for Rate PS, transmission and distribution facilities must be sized to deliver the maximum load that the customer creates on the system. Unlike generation facilities, transmission and distribution facilities are designed to meet localized demands placed on the system by customers. The Company is therefore proposing to implement a 100% ratchet for the component of the demand charge that provides for recovery of transmission and distribution fixed costs. The 100% ratchet will only apply to the Base Demand Charge which currently represents between 25% and 33% of the total demand charges (based on the above calculations).

Q. What is the effective *overall* demand ratchet if you consider all three rate components?

A. As I explained, for TODS, TODP, RTS, and FLS, the 100% ratchet would only apply to the Base Demand Charge and the current 50% ratchet would continue to apply to the Peak and Intermediate Demand Charges. Based on a simple analysis, since the 50% ratchet would apply to the demand charge components (Peak and Intermediate Demand Charge) that represent between 67% to 75% of the demand charges, whereas the 100% ratchet would apply to the demand charge component (Base Demand Charge) that represents between 25% and 33% of the cost, the simple weighted effect of both ratchets works out to be equivalent to a demand ratchet of 62.5% to 66.5%. [75% x 50% + 25% x 100% = 62.5% and 67% x 50% + 33% x 100% = 66.5%.] These effective ratchet percentages are not out of line with demand ratchet percentages typically included in rates applicable to large commercial and industrial customers.

Q. Will changing the demand ratchet for the Base Demand Charge have a large impact on customer's bills?

A. Because the impact will be factored into the determination of the revenue requirement for the rate classes, the change will not result in any more or any less revenue calculated for the class. Specifically, the revenues calculated at the proposed rates are determined by applying the proposed Base Demand Charges for TODS, TODP, RTS and FLS to billing demands for the test year that are reflective of the revised ratchet.

In other words, in determining the proposed revenue for the Base Demand Charges the charges are multiplied by billing demands that are higher than what would otherwise be billed during the forecasted test year. Therefore, from the Company's perspective, the change is revenue neutral. The Company is not expected to collect any more revenue from customers as a result of making this change. While the proposed demand ratchet may protect against revenue erosion if customers install distributed generation, it is not anticipated that the Company will collect additional revenues coming out of the rate case as a result of this change. However, on an individual customer basis, the change will affect some customers more than others. Specifically, the change will result in larger increases to customers with large fluctuations in their monthly demands and in smaller increases to customers with steady demands that don't fluctuate from month to month. A number of manufacturing customers on KU and LG&E's system will benefit from the change, particularly high-load-factor manufacturing or commercial customers with relatively constant demands from month to month. Of course, customers with intermittent loads will see a larger increase.

Q. Do you have any other comments about the proposed change in the demand ratchet?

A. Yes. It is important to note that this proposal will create a level playing field for customers who install distributed generation and rely on KU for backup service and customers with large fluctuations in their monthly demands. From the utility's perspective there is not much difference between serving either type of customer.

Therefore, the proposed rate structure represents a non-discriminatory approach to serving both types of customers while helping to ensure that the utility's other customers are not subsidizing standby customers or customers with large swings in their monthly demands.

G. CURTAILABLE SERVICE RIDER (CSR)

Q. **Please describe the proposed changes to CSR.**

A. The Curtailable Service Rider is a rider that provides a credit to industrial or commercial customers that will interrupt a portion of their load when called upon by KU. Curtailable customers receive a discount in the form of a credit to their demand charges in exchange for their willingness to receive curtailable service on a designated portion of their load. A customer taking service under CSR is subject to a maximum of 375 hours of curtailment (or interruption) during a 12-month period. KU is proposing to lower the CSR credit from \$6.40 to \$3.20 per kVA of curtailable billing demand for transmission voltage service and from \$6.50 to \$3.31 per kVA for primary voltage service. As also discussed in Mr. Conroy's testimony, the Company is proposing to restrict the rider so that it will only be available to customers served under the schedule as of the date new rates go into effect as a result of this proceeding.

Q. **What is the basis for the proposed credit?**

A. As also discussed in the Direct Testimony of David S. Sinclair, KU is proposing to determine the credit based on the fixed carrying costs of the large-frame combustion turbines jointly owned by KU. Specifically, the credit is based on Brown Units 8, 9, 10, and 11, which are wholly owned by KU, and on KU's portion of the fixed costs of the jointly-owned Brown Units 5, 6, and 7, Trimble County Units 5, 6, 7, 8, 9, and 10, and Paddy's Run Unit 13. These units were installed during the late 1990s and early 2000s. It is appropriate to use the fixed carrying costs of these combustion turbine units because these units would be dispatchable for a similar number of hours as the hours of curtailment set forth in the CSR tariff. These units are typically dispatched after KU and LG&E's base load coal-fired steam units, gas-fired combined cycle facility, solar generation facility, and hydro-electric units. Traditionally, load designated to be served under CSR has been used to avoid or defer the installation of peaking units such as combustion turbines which have been dispatched fewer hours of the year than coal-fired steam generating units or gas-fired combined cycle generating units. In the past, the CSR credit has been based on the avoidance or deferral of a hypothetical combustion turbine unit. The Companies currently expect they will have no need to install peaking or other generation capacity through the end of the forecasted test year. Therefore, instead of using the cost of a hypothetical future combustion turbine unit that may or may not be installed during the next decade or more to establish the credit, the Company is proposing to use the fixed carrying costs of the most-recently installed conventional combustion turbines as the basis for the CSR credits.

Q. What do you mean by a "conventional combustion turbine"?

A. A conventional combustion turbine, as opposed to a combined-cycle combustion turbine, is a single cycle turbine for which there is no heat-recovery system that allows heat from the combustion gas to be reused to operate at higher efficiencies. Combined-cycle units have higher fixed costs but operate at greater capability and higher efficiencies, which allows the units to be operated for more hours during the year. KU's combined cycle unit will typically operate for more than 8,000 hours during the year. The operational hours of a combined cycle generating unit or of a coal-fired steam generating unit are in no way comparable to the hours of curtailment set forth in the CSR tariff.

Q. What is a "large-frame combustion turbine"?

A. Beginning in the 1980s, utilities began installing larger combustion turbines that achieved higher efficiencies than their earlier, and typically smaller, counterparts. Large-frame combustion turbines operate at higher capabilities and higher pressures allowing the units to achieve higher efficiencies. All the combustion turbines that KU installed since 1999 have been large-frame units.

Q. How many hours are these combustion turbines dispatched during a 12-month period?

A. It varies from year to year, but the Companies' large-frame combustion turbines will typically be dispatched from 200 to 1,500 hours during a 12-month period. The following table shows the number of hours that the large-frame Brown, Trimble and Paddy's Run combustion turbines owned or jointly-owned by KU were dispatched during the 12 months ended June 30, 2016:

Kentucky Utilities Company's Large-Scale Conventional Combustion Turbine Units	
Generating Unit	**Hours of Operations**
Brown Unit 5	644
Brown Unit 6	270
Brown Unit 7	257
Brown Unit 8	1465
Brown Unit 9	1341
Brown Unit 10	1958
Brown Unit 11	678
Trimble 5	1614
Trimble 6	982
Trimble 7	1632
Trimble 8	371
Trimble 9	1081
Trimble 10	382
Paddy's Run 13	973

Table 9

These units will typically operate for more hours than the maximum number of hours of annual curtailment under the CSR tariff, and they typically have start-up times that are shorter than the 30-minute period that CSR customers can respond to a curtailment. Brown 8, 9, 10, and 11 and Trimble 8 and 10 are quick-start units that can be brought on line and fully loaded in 10 minutes or less. Trimble 8 and 10 are often held in reserve as quick-start capacity for emergencies. While the combustion turbine units listed in Table 9 have operating characteristics that offer greater flexibility than curtailable load, these are still the generating units in the Companies' fleet that are the most comparable in terms of the hours' use of the units and the startup times to the terms and conditions of the CSR rate schedule. The Companies' combined-cycle and coal-fired base load units will typically operate over 8,000 hours per year and have longer startup times, and the Company's older combustion turbines will typically operate less than 100 hours during a 12-month period. Furthermore, the large-frame units listed in the above table are the most recent combustion turbines installed by the Companies.

Q. How are the fixed carrying costs for the large-frame combustion turbine units calculated?

A. The carrying costs are calculated based on the total fixed cost of the units for the fully-forecasted test-year. The fixed carrying charges for the units include the following standard cost-of-service components: (1) return on net investment (rate base), (2) income taxes, (3) depreciation expenses, (4) operation and maintenance expenses, and (5) property taxes. These are the standard items included in a utility's revenue requirements.

Q. Have you prepared an exhibit showing the derivation of the CSR credits?

A. Yes. Exhibit WSS-3 shows the calculation of the CSR credit based on the fixed carrying costs of the Brown, Trimble County, and Paddy's Run 13 combustion turbines. This analysis shows that the credit should be \$3.20/kVA/Month for transmission voltage service and \$3.31/kVA/Month for primary voltage service.

Q. Why is KU proposing to restrict the CSR schedule so that it will only be available to existing customers after the new rates go into effect?

A. As mentioned earlier, KU has no need for additional generation capacity during the next decade or so. The Companies have not issued any curtailments under Rider

CSR since January 2015. Because the current generation mix was planned to take into account CSR capacity and its use in avoiding combustion turbine capacity, the Companies believe that it is appropriate to provide *current* CSR customers a credit based on the actual fixed cost of the most recent combustion turbines that were installed by the Companies.

H. LIGHTING RATES

Q. Explain how the rate increases were determined for the lighting rates?

A. KU offers two rates that include the lighting fixture along with the delivered energy to operate the lights. Those two rates are Lighting Service (LS) and Restricted Lighting Service (RLS). The Company also offers two types of delivered energy service to customers who own their own lighting fixtures or traffic lights. Those two rates are Lighting Energy Service (LE) and Traffic Lighting Service (TE).

The proposed rates for each type of light under Rate LS and Rate RLS were determined by allocating the revenue requirement for the lighting class to each light type based on the cost of each type of lighting fixture. Those costs include the carrying charges, distribution energy costs, and operation and maintenance expenses. The maximum increase for any type of fixture was capped at 20%. KU is proposing comparatively smaller increases for mercury vapor lights because incandescent and mercury vapor lights are no longer being replaced and, in some cases, they are approaching their depreciable lives. The current unit revenue requirement of fixtures under Rate LS and Rate RLS is shown in Exhibit WSS-4. The proposed charge for each fixture type is shown on pages 16 through 21 of Schedule M-2.3 of the Filing Requirements.

KU is not proposing an increase to Rate LE. Therefore, the Energy Charge for Rate LE remains at $0.07328/kWh. For Rate TE, the Company is not proposing to increase the Basic Service Charge from its current level of $4.00 per delivery point per month; however, KU is proposing to increase the Energy Charge from $0.08740/kWh to $0.09289/kWh.

Q. Is KU proposing to offer any new types of lights?

A. Yes. KU wants to be proactive in encouraging energy efficiency by offering light emitting diode ("LED") lights. The lights being offered correspond to the size and style of the most popular conventional lights offered by the Company. The new lights to be offered are: (1) 50 Watt Open Bottom Overhead Yard Light; (2) 80 Watt Overhead Cobra Head Light; (3) 134 Watt Overhead Cobra Head Light; (4) 228 Watt Overhead Cobra Head Light; (5) 80 Watt Underground Cobra Head Light; (6) 134 Watt Underground Cobra Head Light; (7) 228 Watt Underground Cobra Head Light; and (8) 68 Watt Underground Colonial Light. While LED lights are more energy efficient than traditional lighting fixtures, the cost of an LED fixture tends to be higher than the cost of a conventional fixture, and the average service life ("ASL") for an LED fixture is expected to be lower. This could ultimately result in higher depreciation expenses for all lights.

Q. How did KU develop the proposed charges for these new lights?

A. The rates for these lights were determined using a standard revenue requirement approach, with carrying charges, distribution energy costs, and operation and maintenance expenses included as revenue requirements for the monthly rates. The carrying charges include depreciation expenses, return on investment, income taxes and property taxes. The support for the proposed rates for LED lights is included in Exhibit WSS-5.

I. REDUNDANT CAPACITY (RC)

Q. Please describe KU's Redundant Capacity rider.

A. The Redundant Capacity rider allows customers that have one or more redundant distribution feeds to reserve back-up capacity on the distribution system. This rider would typically be used by customers who want greater assurance that their service will not be interrupted because of an outage on a distribution line. These customers would want a redundant feed along with automatic relay equipment capable of switching from a principal circuit to a backup circuit if electric service from the primary feed is lost. With the greater use of technology, some customers are finding it increasingly difficult to tolerate electrical outages for even short periods of time.

Q. How is a customer charged for redundant capacity?

A. A customer who wants a second feed must pay the cost of the customer-specific facilities required to provide the feed, including the second distribution line, automatic relay equipment, or other customer-specific facilities that may be required. Customers can pay for the customer-specific facilities by either making a contribution-in-aid-of-construction or by taking service under the Company's Excess Facilities rider. If the customer wants to have full backup capacity on the second feed, there are additional costs incurred by KU of ensuring that there is sufficient network distribution capacity to provide full backup if a relay occurs on the automatic switchgear. To ensure that there is sufficient capacity on the redundant feed to serve the load if the primary feed goes down, the utility must plan the distribution facility as if there were two customers placing demands on the system. For this reason, KU assesses a demand charge to cover the distribution demand-related cost of providing backup service for new customers with redundant feeds. The demand charge is applied to the customer's monthly billing demand determined under the standard rate schedule under which the customer receives service. Rider RC includes a charge for customers taking service at primary voltages and a charge for customers taking service at secondary voltages.

Q. What changes is KU proposing to the Redundant Capacity charges?

A. KU is proposing to decrease the demand charge for primary voltage customers from \$1.11 to \$0.90 per kW per month and from \$1.12 to \$1.09 per kW per month for secondary voltage customers. The cost support for the proposed redundant capacity charges is included in Exhibit WSS-6.

IV. MISCELLANEOUS SERVICE CHARGES

A. POLE AND STRUCTURE ATTACHMENTS (RATE PSA)

Q. Is the Company proposing to adjust the pole attachment charge?

A. Yes. Changes to the tariff language are discussed in Mr. Conroy's testimony. As described in Mr. Conroy's testimony, the Company is broadening the tariff to include not only charges for cable television attachments but also charges for telecommunication wireline and wireless facilities that are attached to KU's poles and cable television and telecommunications wireline facilities utilizing the Company's underground infrastructure. In the proposed schedule, the Company is proposing three charges: (1) an annual charge per standard pole attachment which is based on one foot of the usable space on the pole; (2) an annual charge per attachment for wireless telecommunication facilities such as antennas, risers, transmitters, and receivers when they are attached to the Company's poles; (3) an annual charge per linear foot of duct that will be applicable when the Company's underground infrastructure is utilized for cable television or telecommunication wireline facilities. Cable television companies are currently covered by the Company's rate schedule, but other telecommunication attachments are billed pursuant to individual contracts with the companies or organizations that attach to KU's poles. KU is proposing that as these individual contracts expire then the attachments would be transitioned to and covered by Rate PSA. I will address the derivation of the charges for the rate schedule in my testimony below.

Q. Is KU proposing any increases to the attachment charges that would be applicable to cable television companies?

A. No. The Company is proposing to maintain the pole attachment charge applicable to cable television companies at the current level of $7.25 per attachment. When I calculated the attachment charges using forecasted costs based on a revenue requirements reflecting net cost plant (net cost rate base), the analysis resulted in a unit cost for KU and LG&E of $7.45 per attachment. Because the current charge reasonably reflects the updated cost based on forecasted net plant, the Company decided not to propose a change in the rate at this time.

Q. Is the Company proposing to apply this same rate to other wireline attachments?

A. Yes.

Q. Please describe the methodology used to calculate the charges.

A. In its Order in Administrative Case No. 251, the Commission prescribed a methodology for determining the attachment charges. The calculations set forth in Exhibit WSS-7 follow the guidelines established in Administrative Case No. 251. In this exhibit, the weighted average carrying costs are calculated for 35, 40 and 45 foot poles. The charge is calculated by multiplying a usage factor of 0.0759 by the annual carrying costs of a bare pole. The 0.0759 usage factor was the prescribed percentage for a three-user pole set forth in the Commission's Order in Administrative Case No. 251 dated September 17, 1982, and assumes that a cable television attachment would utilize one foot of the usable space on the pole. In calculating bare pole costs, 15% of the pole costs have been removed from plant in service costs for 35, 40 and 45 foot poles to reflect the elimination of appurtenances.

The calculations set forth in Exhibit WSS-8 for the duct attachment charge follow the same carrying charge methodology except the cost of conduit investment is utilized. In calculating the cost per foot of duct, the methodology for determining the applicable linear feet of duct is consistent with the methodology described in the *Report and Order* issued in CS Docket No. 97-98 by the Federal Communications

Commission on April 3, 2000.

Q. How are the carrying charges calculated?

A. They are calculated using a standard revenue requirement (cost of service) methodology. The carrying charges include the following cost-of-service components: (1) return on net investment (rate base), (2) income taxes, (3) depreciation expenses, (4) O&M expenses, and (5) property taxes. These are the standard items included in a utility's revenue requirements.

Q. Are the charges based on net depreciated plant?

A. Yes. Net depreciated plant (or rate base), along with straight line depreciation, is used in the carrying charge calculation. This approach is consistent with the way that all other revenue requirements are determined in this proceeding. Therefore, the charges shown in Exhibits WSS-7 and WSS-8 are reflective of current revenue requirements associated with the cost of providing attachment service.

Q. What is the proposed charge for attaching wireless facilities to a pole?

A. The proposed charge for attaching a wireless facility is $84.00 per year per attachment. This charge was determined by multiplying the annual charge for a standard attachment by 11.585 feet, which corresponds to the average space currently used for each wireless facility.

Q. What is the proposed duct attachment charge?

A. The proposed charge for a duct attachment is $0.81 per year per linear foot of duct.

Q. Is there a revenue impact for these changes?

A. Yes. There is a small revenue impact. While KU is not proposing to change the rate applicable to cable television companies, the Company will apply the rate to all other wireline attachments as the contracts that are currently in place for such attachments expire. For purposes of calculating the impact on miscellaneous revenues in this proceeding, the Company assumes that all wireline contracts will expire during the test year, resulting in an increase in miscellaneous revenue of $19,720. (For LG&E, there is a revenue decrease that is approximately equal to this amount.) The support for the change in miscellaneous revenues is shown in Exhibit WSS-9.

B. UNAUTHORIZED RECONNECTION CHARGE

Q. Is KU proposing an Unauthorized Reconnection Charge and what is it?

A. Yes. KU is proposing to add an Unauthorized Reconnection Charge to its tariffs that will allow the Company to recover the cost of addressing theft of service in excess of any back-billing of energy and/or demand charges for stolen service. Specifically, the Unauthorized Reconnection Charge is a set of charges that would apply when a customer either connects or reconnects to the Company's service without authorization. Because these reconnects will typically involve some type of meter tampering, the charge will vary depending on whether the Company's metering equipment has been damaged and needs to be replaced. The need for the charge is discussed in Mr. Conroy's testimony. I will discuss the calculation of the standard charges that would apply.

Q. Please describe the various Unauthorized Reconnection Charges that KU is proposing and how they are calculated?

A. The Company is proposing the following charges: (1) an Unauthorized Reconnection Charge of $70.00 for an unauthorized connection or reconnection that does not require the replacement of the meter; (2) an Unauthorized Reconnection Charge of $90.00 for an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter; (3) an Unauthorized Reconnection Charge of $110.00 for an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading ("AMR") meter; (4) an Unauthorized Reconnection Charge of $174.00 for an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Metering System ("AMS") meter; and (5) an Unauthorized Reconnection Charge of $177.00 for an unauthorized connection or reconnection that requires the replacement of a three-phase meter. The cost support for these charges is included in Exhibit WSS-10. The charge includes the labor cost of a field investigator and back-office support, transportation costs, cost associated with the installation of a locking device to prevent future meter tampering, and the cost of replacing the meter if necessary.

Q. Will implementing this rate result in increased miscellaneous revenues?

A. No. The Company has been recovering the costs from customers who have tampered with their meter based on the out-of-pocket expenses incurred by the Company. Since the proposed rate is determined on the same basis (i.e., on the basis of average out-of-pocket expenses), there will be no difference between the forecasted charges reflected in the determination of revenue requirements and the revenues that would be collected from the implementation of a standard charge in the tariff.

V. COST OF SERVICE STUDY

Q. Did The Prime Group prepare a cost of service study for KU's operations based on forecasted financial and operating results for the 12 months beginning July 1, 2017?

A. Yes. The Prime Group prepared a fully allocated embedded cost of service study based on a forecasted test year beginning July 1, 2017. The cost of service study corresponds to the pro-forma financial exhibits that the Company has provided to meet the requirements of Section 16(8). The objective in performing the cost of service study is to allocate KU's revenue requirement as fairly as possible to all of the classes of customers that KU serves, to determine the rate of return on rate base that KU is earning from each customer class, and to provide the data necessary to develop rate components that more accurately reflect cost causation.

The Prime Group prepared two versions of the cost of service study using alternative methodologies to time-differentiate and allocate fixed production costs. In the first version of the cost of service study, the modified Base-Intermediate-Peak ("BIP") methodology used in prior KU and LG&E cost of service studies was utilized. In the second version of the study, a Loss-of-Load-Probability ("LOLP") methodology was utilized. I will describe the two methodologies later in my testimony. All other costs, including variable production costs, transmission costs, and general plant are handled the same way in both versions of the study.

Q. What model was used to perform the cost of service study?

A. The cost of service study was performed using an EXCEL™ spreadsheet model that was developed by The Prime Group and that has been utilized in previous filings by KU to support requests for adjustments in its rates.

Q. What procedure was used in performing the cost of service study?

A. Regardless of whether a historic test year or a forecasted test year is used to develop a cost of service study, the methodology for developing a cost of service study is basically the same. However, because KU operates in multiple jurisdictions, it is necessary to identify costs for the Kentucky jurisdiction prior to developing a cost of service study. Therefore, the spreadsheet model used to perform the cost of service study also includes a jurisdictional separation analysis. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods which time differentiates the costs. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then finally (4) costs were allocated to the rate classes. These steps are depicted in the following diagram (Figure 1).

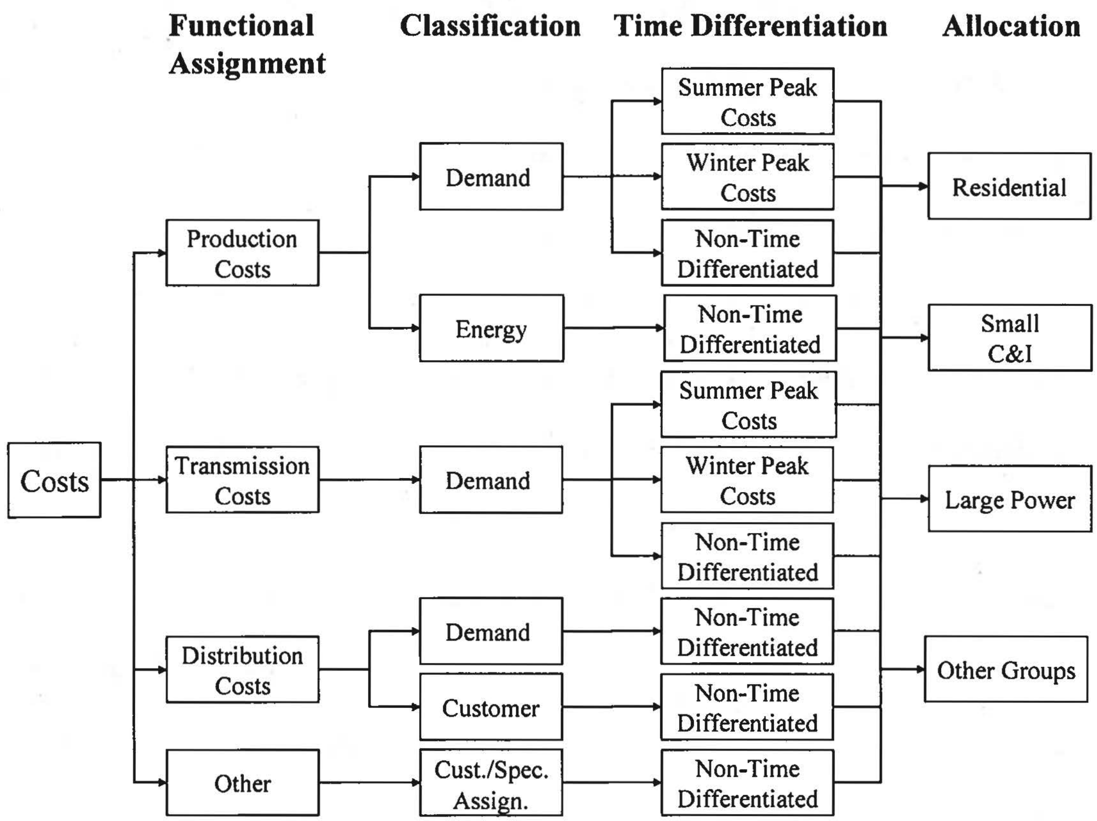


Figure 1

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. How were costs time differentiated and allocated in the version of the study that utilized the BIP methodology?

A. The BIP method is used to assign production costs to the relevant costing periods.[1] Using this methodology, production demand-related costs (fixed costs) were assigned to three categories of capacity – base, intermediate, and peak. The percentages of production fixed cost that were assigned to the base period were determined by dividing the minimum system demand by the maximum demand. The percentages of production fixed cost that were assigned to the intermediate period were calculated by dividing the winter peak demand by the summer peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer or winter peak periods or assigned as non-time-differentiated. Base costs were assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. In applying the modified BIP methodology, what demands were used?

A Demands for the combined KU and LG&E systems were used to determine the costing periods and in determining the percentages of production fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly, developing costing periods and assigning costs to the costing periods based on the

[1] In Case No. 90-158, the Commission found LG&E's cost of service study, which utilized the modified BIP methodology, to be "acceptable and suitable for use as a starting point for electric rate design." (Order in Case No. 90-158, dated December 21, 1990, at 58.)

combined loads for KU and LG&E accurately reflects cost causation. Developing the costing periods and allocation factors in the cost of service study based on the combined loads for KU and LG&E does not result in any shifting of booked expenses from one utility to the other. LG&E's cost of service study relied on LG&E's accounting costs, and KU's cost of service study relied on KU's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the KU and LG&E cost of service studies.

Q. What percentages were assigned to the costing periods using the BIP methodology?

A. Exhibit WSS-11 shows the application of the BIP methodology. Using this methodology 34.38% of KU's production and transmission fixed costs were assigned to the winter peak period, 36.02% to the summer peak period, and 29.60% as base period costs that are non-time-differentiated.

Q. How were costs time differentiated and allocated in the version of the study that utilized the LOLP?

A. LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour. Loss of load probability therefore takes into consideration the magnitude of the load, installed generation capacity, forced outage rates, maintenance schedules, and ramp-up rates of generating units. LOLP can be calculated for any period – an hour, a day, a week, etc. LOLP is a critical measurement used by KU and LG&E in planning its generation resources. Specifically, it is used to evaluate the level of reserve margins that the Companies target. Therefore, LOLP can serve as a foundation for allocating fixed production costs to the classes of customers. In other words, allocating fixed production costs on the basis of LOLP links the cost-of-service allocation methodology to a key measurement used by KU and LG&E to plan the system.

For the cost of service study, LOLP was calculated for each hour of the test year based on the hourly loads for the test year and the characteristics of KU and LG&E's generating facilities, including capacity, forced outage rates, and maintenance schedules. Hourly loads for each rate class were then weighted by the LOLP for each hour to determine LOLP weighted hourly load for each rate class. The weighted loads for each rate class are then summed for the test year to determine a production fixed cost allocator. Mathematically, this is equivalent to calculating an allocation vector for fixed production costs using the following formula:

$$\overline{PROD\ ALLOCATOR} = \sum_{i=1}^{8760} LOLP_i * \overline{LOAD_i}$$

Where: $\overline{PROD\ ALLOCATOR}$ is the allocation vector for production fixed costs in the cost of service study;

$LOLP_i$ is the Loss of Load Probability for hour i;

$\overline{LOAD_i}$ is a vector of hourly load (in kW) for each rate class at hour i; for example, $\overline{LOAD_i}$ = (load for Rate RS at hour i, load for Rate GS for hour i, load for Rate PS at hour i, …);

i is the hour of the year;

The allocation vector $\overline{PROD\ ALLOCATOR}$ is then used to allocate fixed production costs to the customer classes in the cost of service study.

Q. But is the LOLP approach a time-differentiated methodology?

A. Yes, and at a fine level of granularity. With the LOLP methodology, costs are differentiated for each hour of the test year. The approach can also be adapted to calculate costs for any set of time periods during the test year, including the base, intermediate and off-peak periods used in the BIP, or the approach can be adapted to calculate costs for other time periods that may be more appropriate for rate design. Exhibit WSS-12 is a summary of the production fixed cost allocators used in the LOLP version of the study.

Q. Why are you presenting an alternative methodology for allocating fixed production costs?

A. While the BIP methodology has been accepted by the Commission as a basis of developing rates in prior rate cases, the LOLP methodology more closely reflects how KU and LG&E's generation resources have been planned over the past 30 years or so and how the Companies' generation resources are currently planned. Therefore, the LOLP version of the study provides useful information for the development of rates.

Q. How were costs classified as energy-related, demand-related or customer-related?

A. Classification involves utilizing the appropriate cost driver for each functionally assigned cost which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. For costs classified as *energy-related*, the appropriate cost driver is the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand-related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. The costs of production plant and transmission lines are examples of costs typically classified as demand-related costs. Costs classified as *customer-related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, a portion of the costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related because these costs do not vary with customers' capacity or energy usage.

Q. **What methodologies are commonly used to classify distribution plant between customer-related and demand-related components?**

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of the minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the average number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is preferred over the minimum system methodology when the necessary data is available. Additionally, KU has utilized the zero-intercept methodology in determining customer-related costs in prior rate case filings before this Commission. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer-related component of distribution costs. In the zero-intercept methodology, the estimated cost of a zero-size conductor or line transformer is the absolute minimum system for determining customer-related costs.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost of conductor ($/ft) or line transformers ($/kVA of transformer size) and the load flow capability of the plant measured as the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero-intercept. The zero-intercept is essentially the cost component of conductor or transformers that is invariant to the size and load carrying capability of the plant.

Like most electric utilities, the feet of conductor and the number of transformers on KU's system are not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted linear regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted linear regression analysis all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

Using a weighted linear regression analysis, the cost and size of each type of conductor or transformer is weighted by the number of feet of installed conductor or the number of transformers. In a weighted linear regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

Q. Has the Commission accepted the use of the zero-intercept methodology?

A. Yes. The Commission found LG&E's cost of service studies submitted in Case No. Case No. 90-158 to be reasonable, thus providing a means of measuring class rates of return that are suitable for use as a guide in developing appropriate revenue allocations and rate design. The cost of service studies in both proceedings utilized a zero-intercept methodology to calculate the splits between demand-related and customer-related distribution costs. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2014-00371 and 2014-00372, the Companies' last general rate case filings.

Q. Have you prepared exhibits showing the results of the zero-intercept analysis?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Exhibits WSS-13, WSS-14 and WSS-15, respectively.

Q. Have you prepared an exhibit showing summarizing the results of the functional assignment, time-differentiation and classification steps of the cost of service study?

A. Yes. Exhibit WSS-16 shows the results of the first three steps of the cost of service study for the BIP version of the study, namely functional assignment, classification, and time differentiation. Exhibit WSS-17 shows the same three steps for the LOLP version of the study. The first column of numbers in these two exhibits reflect plant costs and expenses for KU's Kentucky retail jurisdiction. In the cost of service model used in this study, the calculations for functionally assigning, classifying and time differentiating KU's accounting costs are made using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*[2]) by the dollar amount in the various accounts to simultaneously functionally assign, classify and time differentiate KU's accounting costs. These calculations are made in the portion of the cost of service model included in Exhibits WSS-16 and WSS-17. In these exhibits, KU's accounting costs are functionally assigned, classified and time differentiated using explicitly determined functional vectors and using internally generated functional vectors. The explicitly determined

[2] "Scalar multiplication" is the multiplication of each element of a vector by a constant (scalar). Scalar multiplication is different from "vector multiplication," in which one vector is multiplied by another vector either as a dot product (whose product is a scalar) or as a cross product (whose product is another vector).

functional vectors, which are primarily used to direct where costs are functionally assigned, classified, and time differentiated, are shown on pages 49 through 52 of Exhibits WSS-16 and WSS-17. Internally generated functional vectors are utilized throughout the study to functionally assign, classify and time differentiate costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 49 through 52 of Exhibits WSS-16 and WSS-17. An example of this process is the use of total O&M expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign, classify and time differentiate these costs on the same basis. (See Exhibits WSS-16 and WSS-17, pages 9 through 12, for the functional assignment, classification and time differentiation of cash working capital on the basis of OMLPP shown on pages 25 through 28.) The functional vector used to allocate a specific cost is identified in the column of the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Q. Please describe how the functionally assigned, classified and time differentiated costs were allocated to the various classes of customers that KU serves.

A. Exhibits WSS-18 and WSS-19 show the allocation of the functionally assigned, classified and time differentiated costs to the various classes of customers that KU serves using the BIP methodology and the LOLP methodology, respectively. For a forecasted test year, the average number of customers is used for allocating customer-related costs rather than the year end number of customers that is used for a historic test year. The following allocation factors were used in the cost of service study to allocate the functionally assigned, classified and time differentiated costs:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the loss adjusted kWh sales to each class of customers during the test year.
- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPT** – The demand cost component is allocated based on the maximum class demands for transmission, primary and secondary voltage customers. This allocation vector is used to allocate transmission costs.
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers. This allocation vector is used to allocate distribution substations and primary distribution demand-related costs.
- **SICD** – The demand cost component is allocated on the

basis of the sum of individual customer demands for secondary voltage customers.

- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **Cust04** – Customer-related costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05 and Cust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor calculated using the average number of customers for the test year based on discussions with KU's meter reading, billing and customer service departments.
- **Cust07** – Customer-related costs are allocated on the basis of the average number of customers using line transformers and secondary voltage conductor.
- **Cust08** – Customer-related costs are allocated on the

basis of the average number of customers using primary voltage conductor.

Q. Once costs are functionally assigned, classified and time differentiated, what calculations are used to allocate these costs to the various customer classes that KU serves?

A. Once costs for all of the major accounts are functionally assigned, classified, and time differentiated, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, O&M Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". A transpose of a matrix is formed by turning all the rows of a given matrix into columns and vice-versa. This process results in the columns of functionally assigned, classified and time differentiated costs becoming rows in the transposed matrix which then can be allocated to the various classes of customers that KU serves. This process is illustrated in Figure 2 below.

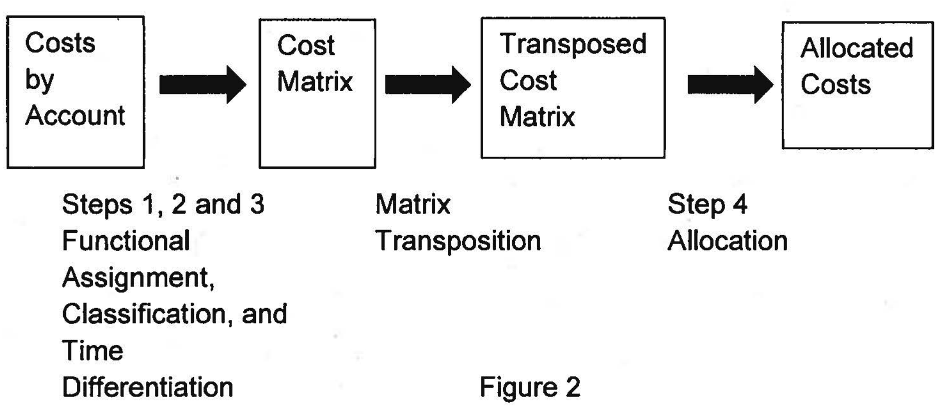


Figure 2

The results of the class allocation step of the cost of service study are included in Exhibits WSS-18 and WSS-19. The costs shown in the column labeled "Total System" in Exhibits WSS-18 and WSS-19 were carried forward from the functionally assigned, classified and time differentiated costs shown in Exhibits WSS-16 and WSS-17, respectively. The column labeled "Ref" in Exhibits WSS-18 and WSS-19 provides a reference to the results included in Exhibits WSS-16 and WSS-17.

Q. Please summarize the results of the cost of service study.

A. The following table (Table 14) summarizes the rates of return for each customer class after reflecting the rate adjustments proposed by KU under the BIP version of the study and the LOLP version of the study. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the rate base, income and expenses discussed in the testimony of Mr. Garrett. The Proposed Rates of Return were calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

Rate Class	Rate of Return on Rate Base at Current Rates		Rate of Return on Rate Base at Proposed Rates	
	BIP Version	LOLP Version	BIP Version	LOLP Version
Residential Service	4.16%	4.36%	5.64%	5.85%
General Service	9.10%	9.20%	10.95%	11.05%
All Electric Schools	5.27%	6.77%	7.07%	8.75%
Primary Service-Secondary	9.61%	9.26%	11.51%	11.12%
Primary Service-Primary	11.83%	10.70%	13.77%	12.55%
Time-of-Day Secondary Service	6.42%	6.06%	8.30%	7.91%
Time-of-Day Primary Service	4.48%	4.05%	6.57%	6.10%
Retail Transmission Service	4.55%	4.50%	6.76%	6.72%
Fluctuating Load Service	1.50%	1.24%	3.44%	3.14%
Lighting Energy Service	9.83%	18.57%	9.82%	18.56%
Traffic Energy Service	10.02%	11.34%	11.66%	13.11%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	8.83%	9.66%
Total All Classes	5.56%	5.56%	7.29%	7.29%

Table 14

The determination of the actual adjusted and proposed rates of return are detailed on pages 29 and 30 and pages 33 through 34, respectively, of Exhibits WSS-18 and WSS-19.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is the Managing Partner with The Prime Group, LLC, and that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of November 2016.

Notary Public (SEAL)

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

AG Exhibit 3

OAG EXHIBIT 3

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	CASE NO. 2008-00409
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: October 31, 2008

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of East Kentucky Power Cooperative, Inc. ("EKPC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to present the financial summary and supporting exhibits detailing how EKPC derived the amount of the requested revenue increase, (ii) describe EKPC's proposed pro-forma revenue, expense, and rate base adjustments, (iii) describe the calculation of EKPC's adjusted net margin and revenue deficiency for the fully forecasted test period ended May 31, 2010, (iv) describe the calculation of the 13-month average of EKPC's rate base and capitalization for the fully forecasted test period; (v) to sponsor the fully allocated class cost of service studies based on EKPC's cost of providing service for the 12 months ended May 31, 2010; and (vi) to support EKPC's proposed wholesale rates to its members.

Q. Please summarize your testimony.

A. EKPC is proposing a rate increase which is designed to produce additional revenues of approximately $67.9 million. EKPC's proposed rate increase is supported by a fully forecasted test period corresponding to the 12 months ended May 31, 2010. The level of the increase is supported by an analysis of EKPC's revenue deficiency based on the pro-forma financial results for the forecasted test period. EKPC's revenue requirement was determined based on net margin requirements necessary to produce a 1.45 Times Interest Earned Ratio ("TIER"). The $67.9 million proposed increase, which was approved by EKPC's Board of Directors, is less than the $70.0 million revenue deficiency determined using a 1.45 TIER.

EKPC's proposed rates will allow it to begin gradually rebuilding its equity, which is currently at a dangerously low level. EKPC's equity as a percentage of total capitalization is expected to drop to around 6.8 percent prior to the implementation of the new rates. It is important to realize, however, that even with the new rates, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which will still not be adequate. One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to its balance sheet in support of its effort to install sufficient generation facilities to meet the needs of its members.

A class cost of service study was performed for the purpose of assisting EKPC in designing its proposed rates. In order to transition to cost-based rates, EKPC is proposing a phased-in approach consisting of *Phase I* rates – which would be placed into effect upon approval by the Kentucky Public Service Commission ("Commission"), which presumably will be at the end of the suspension period in this proceeding, and "Phase II" rates – which would go into effect 12 months later. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenue, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study.

Q. **Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?**

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Vol. 1	Tab 20
Section 10(8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Vol. 1	Tab 21
Section 10(9)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	Vol. 2	Tab 23
Section 10(9)(v)	Cost of service study based on methodology generally accepted in the industry and based on current and reliable data from a single time period.	Vol. 5	Tab 44

Filing Requirement	Description	Volume	Tab #
Section 10(10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Vol. 5	Tab 46
Section 10(10)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of rate base.	Vol. 5	Tab 47
Section 10(10)(h)	Computation of revenue conversion factor for forecasted period	Vol. 5	Tab 53
Section 10(10)(l)	Narrative description and explanation of all proposed tariff changes	Vol. 5	Tab 57
Section 10(10)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes	Vol. 5	Tab 58
Section 10(10)(n)	Typical bill comparison under present and proposed rates for all customer classes	Vol. 5	Tab 59

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Revenue Requirements, (IV) Cost of Service Study, and (V) Rate Design.

II. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville

Gas and Electric Company. From May 1979 until December 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left Louisville Gas and Electric Company in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for well over 130 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions regarding revenue requirements, cost of service and rate design. A listing of my testimony in other proceedings is included in Seelye Exhibit 1.

Q. Have you performed cost of service studies and developed rates for electric cooperatives?

A. Yes. I have performed cost of service studies and developed rates for a number of generation and transmission cooperatives ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power Association, Big Rivers Electric Corp, Southern Illinois Power Cooperative, Corn Belt Power Cooperative, and EKPC. I have also supervised the preparation of cost of service studies and the development of rates for over 130 electric distribution cooperatives.

III. REVENUE REQUIREMENTS

Q. Please describe how EKPC's proposed revenue increase was determined?

A. EKPC is proposing a general adjustment in rates supported by a fully forecasted test period. The proposed revenue increase is supported by an analysis of the revenue deficiency based on financial results for the forecasted test period. The revenue deficiency was determined as the difference between (i) EKPC's adjusted net margins for the forecasted test period without reflecting a general adjustment in rates, and (ii) EKPC's net margin requirement necessary to provide a 1.45 TIER. Based on the forecasted test year, the revenue deficiency is $70,041,960. EKPC's proposed wholesale rates to its members are projected to produce increased revenues of $67,858,922 based on estimated billing determinants for the forecasted test year.

Q. Why is the proposed revenue increase of $67,858,922 less than EKPC's revenue deficiency of $70,041,960?

A. The rates that EKPC is proposing in this proceeding were approved by EKPC's Board of Directors on September 9, 2008. However, the rates were developed using preliminary revenue requirement and billing determinant estimates which indicated that the revenue requirement was approximately $67.7 million based on a forecasted test period for the 12 months ended April 30, 2010, rather than the 12 months ended May 31, 2010, used in the rate case filing. Because EKPC was unable to file the rate case application until the end of October 2008, the forecasted test year utilized in the rate case filing had to be delayed by one month in order to meet the requirement set forth in KRS 278.192 that the forecasted test period must correspond to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. When EKPC finalized the revenue requirement using costs for the fully forecasted test period that had to be utilized in this proceeding, the revenue requirement turned out to be $70.0 million rather than $67.7 million. Likewise, when the rates that were approved by the Board of Directors were applied to test-year billing determinants, the revenue increase turned out to be $67.9 million rather than the $67.7 million amount indicated in the Board resolution provided as an exhibit to Mr. Marshall's testimony. Because the proposed revenue increase is less than the revenue deficiency determined based on operating results for the fully forecasted test period, EKPC made the decision not to revisit the issue with its Board of Directors for the purpose of obtaining approval to propose a larger increase with the Commission. Particularly, EKPC decided to maintain its proposed rates in this proceeding at the level approved by its Board of Directors even though a higher revenue increase could be supported.

Q. **Why did EKPC choose to support the proposed rate increase with a fully forecasted test period?**

A. As the Commission is well aware, EKPC has been in financial distress since 2005. Its interest and debt coverage ratios are forecasted to be inadequate to meet the requirements set forth in the mortgage and credit facility agreements with its lenders. Without a rate increase, EKPC's financial condition will deteriorate even further once Spurlock 4 is placed into commercial operation. Considering its dangerously low level of equity capital, without increasing its rates it would be difficult for EKPC to withstand the stress of an unanticipated expense, such as expenditures that might result from an unanticipated equipment failure at one of its generating stations. Spurlock 4, a 278 MW coal-fired generating unit which will cost approximately $528 million, is scheduled to be placed into commercial operation on April 1, 2009. None of the cost of Spurlock 4 is currently in rate base. EKPC has not included the Construction Work In Progress ("CWIP") for Spurlock 4 in rate base. Because it has been accruing an Allowance for Funds Used During Construction ("AFUDC") on its construction expenditures, EKPC is currently not recovering interest expenses associated with Spurlock 4 through rates. Once Spurlock 4 is placed into commercial operation, EKPC will experience a significant increase in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses. Although Spurlock 4 will result in fuel and purchased power cost savings, those savings will be automatically passed along to its members through the application of the monthly fuel adjustment clause. Therefore, the fuel cost savings will not off-set the impact on EKPC's net income from placing Spurlock 4 in service.

With that background, it is easier to understand why EKPC is supporting its rate increase with forecasted test period costs. If EKPC were to use a historical test year, the very earliest that any of the costs of Spurlock 4 would be reflected in historical test period costs would be in April 2009. EKPC simply could not wait until after April 2009 to file a rate case application, which would not provide additional revenues to cover the increased costs of Spurlock 4 until approximately nine months later. Even though EKPC has never filed a fully forecasted rate case, it was critical that the company move forward with a forecasted rate case considering the serious consequences of not being able to adjust its rates until after April 1, 2009. In its Order in Case No. 2006-00472 dated December 5, 2007, the Commission directed EKPC to file its next base rate case when conditions warrant. Given EKPC's precarious financial circumstances, conditions warrant filing a rate case utilizing a forecasted test year that provides increased revenues to cover the additional costs associated with Spurlock 4.

Q. What are the forecasted test period and the base period for the rate case application?

A. The *forecasted test period* for the filing is the 12 months ended May 31, 2010. Consistent with KRS 278.192, the forecasted test period used to determine revenue requirements in this proceeding corresponds to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. According to KRS 278.190, the maximum suspension period is six months for a general adjustment in rates supported by a fully forecasted test period. Because the effective date of the EKPC's proposed rates is December 1, 2008, the first 12 consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning June 1, 2009, and ending on May 31, 2010.

The *base period* for the filing is the 12 months ended January 31, 2009. The base period consists of seven months of actual historical data and five months of estimated data. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, and consisting of not less than six months of actual historical data and not more than six months of estimated data. Because EKPC's proposed base period, which begins February 1, 2008, includes more than six months of actual historical data, includes less than six months of estimated data, and begins less than nine months prior to the October 31, 2008 filing date in this proceeding, its proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Why didn't EKPC file its rate case using a fully forecasted test period beginning April 1, 2009, rather than June 1, 2009?

A. Because EKPC is a member-owned G&T cooperative, preparing a rate case involves considerably more steps than for either an investor owned utility or a distribution cooperative. EKPC had to build in enough time to prepare its financial budget incorporating accurate and up-to-date construction cost estimates for Spurlock 4 and other projects, present the proposed financial budget and wholesale rates to its member systems, obtain EKPC Board approvals for its financial budget and proposed rates, develop pass-through rates for its member systems in accordance with the provisions of KRS 278.455, and then provide enough time for the boards of its member systems to approve their individual pass-through rates and publish their individual statutory notices in newspapers across the state. As it turned out, there was simply not enough time between preparing the financial budget incorporating updated construction cost estimates and publishing the member systems' statutory notices that would have allowed EKPC to file a rate case application with rates to be effective six months prior to the suspension period for a forecasted test year.

Q. Given that EKPC's proposed rates would not go into effect until June 1, 2009, won't there be two months when its rates will be unable to provide recovery of the increased costs associated with Spurlock 4?

A. Yes. The fact that EKPC will not be able to offset its increased non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses associated with Spurlock 4 with additional revenues will cause its net margin for April and May, 2009, to deteriorate sharply. The inability to recover Spurlock 4 carrying charges for those two months would have a significant adverse effect on EKPC's fiscal 2009 financial results. Without some sort of rate recovery mechanism to deal with this short-fall, EKPC will never be able to recover these fixed charges, which represents a serious problem for a utility whose interest and debt coverage ratios are dangerously low and whose equity percentage is projected to be only 6.8 percent during April and May, 2009.

Q. How is EKPC proposing to address these uncollected costs associated with Spurlock 4?

A. As described in greater detail in the *Motion for the Creation of a Regulatory Asset Relating to Spurlock Unit 4 Expenses* that is being filed in this proceeding, EKPC is proposing to establish a regulatory asset that would allow it to record the additional revenue that it would have collected in April and May, 2009, if EKPC's new rates would have gone into effect on April 1, 2009, rather than on June 1, 2009. In other words, EKPC would record the additional revenues that would have been billed through the application of the new rates during April and May 2009 in a deferred debit (Account No. 182.4). The amount ultimately recorded as a regulatory asset in Account No. 182.4 would correspond to the billing difference in April and May 2009, (based on forecasted billing determinants) between the rates ultimately approved by the Commission (without the amortization of the regulatory asset) and EKPC's current rates. Therefore, the ultimate amount recorded as a regulatory asset would be based on the rates that the Commission ultimately authorizes in the rate case order, without considering the amortization of the regulatory asset. The regulatory asset – whatever the amount turns out to be – would be amortized over three years and reflected in the final rates approved by the Commission.

As an alternative to setting up a regulatory asset to provide recovery of the unbilled Spurlock 4 carrying charges, the Commission could waive its six-month *maximum* suspension period applicable to rate applications using a forecasted test period and allow EKPC to place its proposed rates into effect on April 1, 2009, subject to refund. Because this alternative could possibly require that EKPC's member systems make refunds to their retail members, allowing EKPC to establish a regulatory asset would represent a simpler approach.

Q. Have you prepared an exhibit that shows how EKPC's revenue deficiency is calculated?

A. Yes. Seelye Exhibit 2 shows the calculation of EKPC's revenue deficiency.

Q. Please walk us through Seelye Exhibit 2.

A. The purpose of Seelye Exhibit 2 is to calculate the difference between EKPC's adjusted net margin (deficit) for the forecasted test year and the margin necessary for EKPC to achieve a 1.45 TIER. The exhibit starts out with Operating Revenue and Patronage Capital from EKPC's budget for the 12 months ended May 31, 2010 (line 1). This amount is obtained from the 2009 and 2010 budgets that were approved by EKPC's Board of Directors. EKPC's Board is comprised of a board member from each of its 16 member systems. The monthly and 12-month total budget amounts for the forecasted test year are shown in Exhibit 1 to Mr. Eames's testimony. A number of pro-forma adjustments are applied to Operating Revenue. The pro-forma revenue adjustments are shown on lines 4 through 7 of the exhibit. EKPC's Adjusted Revenue, as adjusted to reflect the four pro-forma revenue adjustments, is shown on line 9.

The Total Cost of Service from EKPC's budget is shown on line 12. In the context of EKPC's budget and financial reports, Total Cost of Service includes operation expenses, maintenance expenses, depreciation and amortization expenses, taxes, interest expenses on long-term debt, other interest expenses, and other deductions. Total Cost of Service is then adjusted to reflect pro-forma adjustments shown on lines 15 through 31 of the exhibit. Adjusted Cost of Service, which reflects the pro-forma expense adjustments, is shown on line 34. Adjusted Operating Margins (line 36) is calculated by subtracting Adjusted Cost of Service (line 34) from Adjusted Revenue (line 9). Interest income (line 39), other non-operating income (line 40), and other capital credits/patronage dividends (line 41) are added to Adjusted Operating Margins (line 36) to determine EKPC's Adjusted Net Margin (Deficit). For the forecasted test-period, EKPC is projected to a have an Adjusted Net Deficit of -$25,603,606 (line 46).

The Revenue Deficiency is calculated on page 2 of Seelye Exhibit 2. To achieve a 1.45 TIER, EKPC needs a net margin requirement of $44,438,354. EKPC's $70,041,960 revenue deficiency corresponds to the difference between this net margin requirement of

$44,438,354 and EKPC's adjusted net deficit of -$25,603,606 (calculated as $44,438,354 - (-$25,603,606) = $70,041,960).

Q. Why was a 1.45 TIER used to determine EKPC's revenue requirement?

A. As explained in the prepared direct testimonies of David G. Eames, Jonathon Andrew Don, and Daniel M. Walker, a 1.45 TIER is in line with what other investment-grade G&T cooperatives are earning and is necessary to provide EKPC with an opportunity to maintain its financial integrity, to maintain adequate interest and debt service coverage ratios, and to rebuild its members' equity to a level that will allow EKPC to continue to attract capital on reasonable terms and to serve its members in a safe and reliable manner.

Q. Please explain why it is necessary to make pro-forma adjustments to financial results from EKPC's budget.

A. It was necessary to make a number of pro-forma adjustments to eliminate costs and associated revenues that are recovered through the fuel adjustment clause (FAC) and the environmental surcharge. A number of other adjustments were required to eliminate expenses that are generally not allowed to be recovered through service rates of utilities in Kentucky that are regulated by the Commission. Two other adjustments were required to amortize or re-amortize certain extraordinary expenses. One final adjustment was required to normalize generation overhaul expenses so that forecasted test-year expenses will be representative on a going forward basis. Support for each adjustment is contained in Schedules 1.01 through 1.18 of Seelye Exhibit 2. The pro-forma adjustments are identified as follows:

(a) Eliminate costs recoverable through the FAC and associated revenues (Schedules 1.01, 1.03).

(b) Remove the impact of revenues and expenses included in the environmental surcharge (Schedules 1.02, 1.04, 1.05, 1.06, 1.07, 1.08).

(c) Eliminate expenses normally excluded by the Commission (Schedules 1.09, 1.10, 1.11, 1.12, 1.13, 1.14, 1.15).

(d) Amortize extraordinary expenses (Schedules 1.16 and 1.17).

(e) Normalize overhaul expenses (Schedule 1.18)

Q. **Please describe the adjustments necessary to eliminate expenses and associated revenues related to the fuel adjustment clause.**

A. EKPC is proposing to eliminate all fuel and purchased power expenses that would be recoverable through the FAC, the fuel cost revenue associated with base fuel cost component of the FAC, and projected FAC billings. In other words, EKPC is proposing to remove all fuel cost and fuel cost revenues that would be considered in the application of the FAC, including fuel costs recovered through the base rate component which is collected through base rates. Specifically, adjustments were made to remove fuel cost revenue recovered through base rates (Schedule 1.01), to remove FAC revenue (Schedule 1.01), to remove fuel expenses recoverable through the FAC (Schedule 1.01), and to remove purchased power expenses recoverable through the FAC (Schedule 1.03).

Q. **Please describe the adjustments to eliminate expenses and associated revenues related to the environmental surcharge.**

A. EKPC is proposing to eliminate all environmental costs that would be recoverable through the environmental surcharge and associated environmental surcharge revenue. Specifically, adjustments were made to remove environmental surcharge revenue (Seelye Exhibit 2, Page 1 of 2, line 6), to adjust off-system sales environmental surcharge revenue (Schedule 1.02), to remove operation and maintenance expense recoverable through the environmental surcharge (Schedule 1.04), to remove emissions allowance expense recoverable through the environmental surcharge (Schedule 1.05), to remove property taxes and property insurance recoverable through the environmental surcharge (Schedule 1.06), to remove depreciation expense recoverable through the environmental surcharge (Schedule 1.07), and to remove interest expense recoverable through the environmental surcharge (Schedule 1.08). Because EKPC budgets these revenues and expenses individually they were readily identified from the budget for purposes of removing them from the calculation of the revenue deficiency. EKPC is not proposing any roll-in of environmental costs into base rates in this proceeding.

Q. Please explain the adjustment to off-system sales environmental surcharge revenue (Schedule 1.02) in greater detail.

A. In determining the environmental surcharge, a portion of EKPC's environmental compliance costs recovered through the surcharge are allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses related to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement. Therefore, consistent with the Commission's orders in the most recent rate cases filed by Louisville Gas and Electric Company and Kentucky Utilities Company, an adjustment was made to reduce revenues to reflect the environmental surcharge methodology for allocating environmental costs to off-system sales. (Order in Case No. 2003-00433 , pp 24-25 and Appendix F and Order in Case No. 2003-00434, p. 24 and Appendix F.)

Q. Please explain the adjustment to remove promotional advertising shown in Schedule 1.09.

A. Pursuant to 807 KAR 5:016, this adjustment eliminates Touchstone Energy advertising and other promotional items included in EKPC's budget for the forecasted test year. These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please explain the adjustment to remove certain directors' expenses shown in Schedule 1.10.

A. Consistent with the Commission's Order in Case No. 2006-00472, EKPC is removing a portion of directors' expenses from the forecasted test-year revenue requirement. The items not removed include the following: fees for regular board meetings, chair and secretary fees, committee chair fees, audit committee chair fees, two special board meetings for each member, fees for training seminars, and expenses of $25,000 for the test year. A total of $93,300 of directors' expenses has been removed from test-year operating expenses.

Q. Please describe the adjustments to remove donations in Schedule 1.11, affiliate expenses in Schedule 1.12, lobbying expenses in Schedule 1.13, Touchstone Energy dues in Schedule 1.14, and Miscellaneous Expenses in Schedule 1.15.

A. Consistent with Commission practice, all donations, contributions, and sponsorships are removed from test-year expenses in Schedule 1.11. All affiliate expenses related to Alliance for Cooperative Energy Services (ACES) Power Marketing, Envision Energy Services, LLC, and the propane gas program for members are removed from test-year expenses in Schedule 1.12. It should be noted, however, that fees paid to ACES for their power marketing functions on behalf of EKPC have not been removed from revenue requirements in this proceeding. Consistent with the procedure followed in its last rate case application in Case No. 2006-00472, EKPC is removing lobbying expenses (Schedule 1.13), Touchstone Energy dues (Schedule 1.14), and certain employee-related expenses (Schedule 1.15). These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please describe the adjustment to reflect an amortization of rate case expenses in Schedule 1.16.

A. This adjustment is necessary to include amortization of the expense incurred in conjunction with this rate case. It is consistent with similar adjustments in revenue requirements found reasonable in numerous rate case orders issued by the Commission, including the Commission's Order approving the settlement agreement in Union Light, Heat and Power Company's recent rate case, which was supported by a fully forecasted test period. (In its Order in Case No. 2006-00172 dated December 21, 2006, the

Commission affirmed that the accounting and ratemaking treatments to which the parties stipulated in the settlement agreement, including the amortization of rate case expenses over 3 years, "generally reflect the approach the Commission has followed in previous rate cases", pp. 4 and 8.)

Q. **Please explain the adjustment to reflect the amortization of the 2004 forced outage balance in Schedule 1.17.**

A. In Case No. 2006-00472, the Commission determined that it was appropriate to amortize $20,514,346 of expenses related to a 2004 Spurlock 1 forced outage over a 3-year period. As of the beginning of the forecasted test period on June 1, 2009, EKPC will have amortized $10,257,173, or one half of the original amount, leaving a balance of $10,257,173. EKPC is proposing to amortize the remaining balance of $10,257,173 over three years, resulting in an increase in expenses of $3,419,058.

Q. **Please explain the adjustment to normalize generation overhaul expenses in Schedule 1.18.**

A. This adjustment is necessary to ensure that forecasted test-year expenses will be representative on a going forward basis. During the forecasted test period, EKPC's overhaul expenses are less than the normal level that would be incurred annually by the company. EKPC projects that it will incur $4.8 million in overhaul expenses during the forecasted test year ($2.1 million for Cooper Unit 1 and $2.7 million for Dale Units 1 and 2) compared to an average annual expense of $7.1 million. For the steam generating units, the boiler and generators are overhauled on a 10-year cycle, and the combustion turbines are overhauled on a six-year cycle. The $7.1 million average overhaul expense was calculated by dividing the estimated cost of a boiler/generator overhaul for each steam generating unit in 2009 dollars by 10 years to determine the average amount for the unit, and by dividing the estimated cost of a generator overhaul for each combustion turbine in 2009 dollars by 6 years to determine the average amount for the unit. Therefore, EKPC is proposing a normalization adjustment of $2.3 million, which represents the difference between $4.8 million amount budgeted for the test year and the $7.1 million average level.

Q. Have you prepared exhibits showing the development of the 13-month average rate base and capitalization for the forecasted test year.

A. Yes. Seelye Exhibit 3 shows the development of the 13-month average rate base for the test year, and Seelye Exhibit 4 shows the development of the 13-month average capitalization for the test year. In Seelye Exhibit 3, rate base is shown both with and without environmental assets for which costs are recovered through the environmental surcharge. These environmental assets have been removed from capitalization in Seelye Exhibit 4. It should be noted that EKPC's revenue requirement was determined using a 1.45 TIER, which is an approach that is often utilized by cooperative utilities, rather than a rate of return on rate base or a rate of return on total capitalization, which is used by investor-owned utilities in Kentucky.

Q. Have you prepared an exhibit that shows key financial performance measurements for EKPC with and without the proposed increase?

A. Yes. Seelye Exhibit 5 shows TIER, debt service coverage ratio (DSC), rate of return on net cost rate base, and rate of return on total capitalization for the forecasted test year with and without the proposed increase. The following table summarizes the financial measurements calculated in Seelye Exhibit 5:

FINANCIAL MEASUREMENT	WITHOUT RATE INCREASE	WITH PROPOSED INCREASE
Times Interest Earned Ratio (TIER)	0.74	1.43
Debt Service Coverage Ratio (DSC)	0.81	1.25
Rate of Return on Net Cost Rate Base (ROR)	3.17%	6.19%
Rate of Return on Total Capitalization (ROI)	3.16%	6.16%

It should be noted that the financial measurements shown in this table are calculated using EKPC's proposed revenue increase of $67,858,922 rather than the $70,041,960 revenue deficiency amount necessary to produce a TIER of 1.45. Because EKPCs Board approved increase is used instead of the revenue deficiency, the TIER shown above is slightly lower than the 1.45 TIER that is appropriate for EKPC. The DSC, ROR and ROI are correspondingly lower than what they would otherwise be if the $70,041,960 revenue deficiency were used to calculate these financial measurements.

Q. Based on your experience in developing rates for other G&T cooperatives, are these financial performance measurements that result from applying the proposed rates reasonable?

A. Yes. They are in line with what the G&T cooperatives I have worked with are using to develop rates. It should be noted, however, that none of the G&T cooperatives for which I have developed base rates are subject to regulation by a public service commission. More important, the proposed TIER will allow EKPC to gradually rebuild its equity over time; however, it is important to realize that even with the new rates which are designed to produce a TIER of 1.43, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which is still inadequate. (See Tab 30, page 10 of the filing requirements set forth in the Application.) One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to the balance sheet in support of its effort to install sufficient generation facilities (e.g., Smith Unit 1) to meet the needs of its members.

IV. CLASS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for EKPC's electric operations based on financial and operating results for the fully forecasted test period?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study. The cost of service study corresponds to the pro-forma financial exhibits included in Seelye Exhibit 2. The objective in performing the electric cost of service study is to determine the rate of return on rate base that EKPC is earning from each rate class, which provides an indication as to whether EKPC's service rates reflect the cost of providing service to each rate class.

Q. Did you develop the model used to perform the cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were utilized. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to the rate classes.

Q. Is this a standard approach used in the electric utility industry?

A. Yes.

Q. What functional groups were used in the cost of service study?

A. The following functional groups were identified in the cost of service study: (1) Production, (2) Production Steam – Direct, (3) Transmission, (3) Distribution Substation, and (4) Distribution Meters. Production Steam – Direct corresponds to production costs that are specifically assigned to provide steam service to a industrial customer.

Q. How were costs classified as energy related, demand related or customer related?

A. Classification provides a method of identifying the appropriate cost driver for each functionally assigned cost so that the service characteristics that give rise to the cost can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. Distribution meters are the only costs classified as customer-related in the cost of service study.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the electric cost of service study?

A. Yes. Seelye Exhibit 6 shows the results of the first two steps of the cost of service study – functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, EKPC's test-year costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 6, EKPC's accounting costs are functionally assigned and classified using the explicitly determined functional vectors identified in the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28. Internally generated functional vectors are utilized throughout the study to functionally assign costs either on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 27 and 28 of Seelye Exhibit 6. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Seelye Exhibit 6, pages 3 and 4 for the functional assignment of cash working capital on the basis of OMLPP shown on pages 13 and 14.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors".

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 7. The costs shown in the column labeled "Total System" in Seelye

Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 7. The column labeled "Ref" in Seelye Exhibit 7 provides a reference to the results included in Seelye Exhibit 6.

Q. Please describe the allocation factors used in the electric cost of service study.

A. The following allocation factors were used in the electric cost of service study:

- **PENG** – Production energy-related costs are allocated to the rate classes on the basis of the amount of energy (kWh) delivered to each rate class.
- **6CP** – Production demand-related costs are allocated on the basis of the sum of the class coincident peak demands during the six peak months of June, July, August, December, January, and February.
- **STMD** – The fixed production costs directly assigned in the functional assignment section of the cost of service study are allocated to the industrial customer that receives steam service from EKPC.
- **12CP** – Transmission demand-related costs are allocated on the basis of the sum of the 12 monthly class coincident peak demands during the test year.
- **SUBA** – Distribution substations are allocated to the rate class on the basis of cost weighted number of substations for each rate class by substation capacity category.

- **CUST05** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.

Q. How was the cost of providing interruptible service addressed in the cost of service study?

A. Customers taking service under the interruptible service rider are assigned a demand cost credit per kW based on the levelized carrying costs associated with the current cost of a combustion turbine generating unit. The cost credit is calculated in Seelye Exhibit 8. This calculation is based on an installed cost of $550/kW for a combustion turbine and a cost of capital (return) of 7 percent. Subsequent to developing this estimate, it was brought to my attention that this avoided cost credit may be somewhat overstated because the capital cost of financing a new combustion turbine would almost certainly be less than 7 percent. Although the credit shown in Seelye Exhibit 8 may be somewhat overstated, I believe that the avoided cost estimate is within a range that is reasonable, particularly given the volatility in the cost of purchasing new combustion turbines.

Q. Does the cost of service study consider load-following costs that EKPC will likely incur to provide service to non-conforming loads on the system?

A. No. It is my understanding that EKPC is currently having difficulty meeting certain North American Electric Reliability Corporation (NERC) control performance standards as a result of large fluctuations of a non-conforming load in EKPC's control area. EKPC is currently analyzing various options for addressing these load/resource balancing problems. The cost of service study submitted in this proceeding does not consider the load-following costs created by non-conforming loads, which are difficult to quantify. The Midwest Independent System Operator (MISO) and other regional transmission operators are currently developing markets for ancillary services, including markets for the types of regulation services that may possibly be used to follow large non-conforming loads. In the absence of an ancillary service market, EKPC may have to enter into a bilateral agreement to obtain regulation services from an organization that controls large amounts of generation capacity, which could prove to be more costly than services obtained from an ancillary service market. Because it is unclear at this time whether load-following services will be obtained from an ancillary service market, or by entering into a bilateral agreement with a regulation service provider, or in some other manner, EKPC is currently unable to develop a reasonable estimate of the load-following costs associated with serving non-conforming loads.

Q. Please summarize the results of the electric cost of service study.

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the Phase 1 rate adjustments proposed by EKPC. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed earlier in my testimony regarding the determination of EKPC's revenue requirements. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return Phase I Rates**
Rate E	3.20%	6.12%
Rate B	2.53%	6.63%
Rate C	2.33%	6.02%
Rate G	0.50%	4.43%
Large Special Contract	2.86%	5.72%
Special Contract – Pumping Stations	29.52%	29.52%
Steam Service	4.74%	10.66%
Total System	3.17%	6.19%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 7, pages 21-22 and pages 23-24, respectively.

V. RATE DESIGN

Q. Please describe how EKPC proposes to transition to a cost-based rate structure.

A. The unit charge components of EKPC's current rates do not accurately reflect the cost of providing service. From a cost of service perspective, too large of a portion of EKPC's fixed costs are recovered through the energy charge component of its rates. This is particularly true of EKPC's Rate E. The cost of service study indicates that a large portion of its fixed costs that are currently recovered through the energy charge should instead be recovered through the demand charge component of EKPC's rates. Rather than moving to a fully cost-based rate design in a single step, EKPC is proposing to move to a cost-based rate design in two phases. Under its rate design proposal in this proceeding, EKPC's is proposing that its Phase I rates would go into effect upon approval by the Commission, which presumably will be at the end of the 6-month suspension period, and would remain in effect for 12 months, at which time Phase II rates would go into effect and remain in effect as EKPC's on-going rates until superseded by a subsequent rate order. The Phase I rates are designed to serve as a *temporary* or *transitional* rate design until cost-based rates can be implemented in Phase II. A phased-in approach was developed because of concerns expressed by EKPC's member systems about implementing cost-based rates in a short period of time. Although there was a general recognition on the part of the member systems that EKPC's rates should reflect the cost of providing service, a number of member systems expressed a desire to transition to a cost-based rate structure in a more gradual, two-phased manner. This phase-in of cost-based rates would provide the member systems with more time to develop retail rates that reflect wholesale costs and to educate retail customers about how to take advantage of cost-based rate offerings.

Q. Is EKPC's phased-in approach consistent with the ratemaking principle of "gradualism"?

A. Yes.

Q. How were the Phase I rates developed?

A. EKPC's Phase I rates were developed by allocating the proposed revenue increase to each rate component of each rate schedule and special contract on a pro-rata basis, with the exception of the special contract for the pumping stations. In other words, in Phase I

EKPC is proposing to increase each rate component of each rate schedule by the same percentage.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase I rates?

A. Yes. The revenue impact of EKPC's Phase I rates is detailed in Seelye Exhibit 9. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. How were the Phase II rate developed?

A. The Phase II rates were developed based on the results of the cost of service study. Specifically, the individual charges within each rate schedule were based on the unit costs determined from the cost of service study. Consequently, the demand charges, substation charges, and meter-point charges included in the Phase II rates are higher than those included in the Phase I rates. However, the energy charges in the Phase II rates are lower than those included in the Phase I rates.

Q. What is the proposed metering point charge for the Phase II rates?

A. For the Phase II rates, EKPC is proposing to increase the metering point charge from the current level of $125 per month to $230 per month. The $230 charge is supported by the cost of service study.

Q. Please describe the changes to the substation charges in the Phase II rates?

A. EKPC currently has substation categories: (i) 1,000 to 2,999 kVa, (ii) 3,000 to 7,499 kVa, (iii) 7,500 to 14,999 kVa, and (iv) greater than 15,000 kVa. For the Phase II rates, EKPC proposes to incorporate the following six substation categories: (i) 1,000 to 4,999 kVa, (ii) 5,000 to 9,999 kVa, (iii) 10,000 to 14,999 kVa substation, (iv) 15,000 to 29,999 kVa, (v) 30,000 to 50,999, and (iv) greater than 51,000 kVa. These six categories more accurately represent the capacity and cost relationships of the various types of substations that EKPC installs. The proposed unit costs reflect the carrying costs of six categories of substations based on average embedded installed costs.

Q. There are two rate alternatives available to members under EKPC's current Rate E. In the proposed Phase II, rates would this optional rate structure be available.

A. No. In the Phase II rates, the two rate options for Rate E would be eliminated, and the rate schedule would reflect cost-based demand and energy charges.

Q. Would the interruptible credit be modified under the Phase II rates?

A. The interruptible credit is updated for both the Phase I and Phase II rates. For the Phase I rates, the interruptible credit is increased by the same percentage as all other rate components. For the Phase II rates, the interruptible credit is increased to reflect the carrying costs associated with the current cost of installing a combustion turbine, as described earlier in my testimony.

Q. Are the proposed Phase II rates designed to produce the same overall revenue as the Phase I rates?

A. Yes. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenues based on test-year billing determinants, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study. The two sets of rates result in slightly different overall revenues because of rounding.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase II rates?

A. Yes. The revenue impact of EKPC's Phase II rates is detailed in Seelye Exhibit 10. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	)	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

William Steven Seelye, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Subscribed and sworn before me on this 27th day of October, 2008.

Notary Public

My Commission expires: December 8, 2009

AG Exhibit 4

OAG EXHIBIT 4

Standard Rate OSL

OUTDOOR SPORTS LIGHTING SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available as an optional pilot program for secondary and primary service used by a customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty customers. Company will accept customers on a first-come-first-served basis.

RATE

	Secondary	Primary
Basic Service Charge per month:	$90.00	$240.00
Plus an Energy Charge per kWh of:	$ 0.03288	$ 0.03189
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 16.75	$ 16.88
Base Demand Period	$ 3.03	$ 3.03

Where:
the monthly billing demand for the Peak Demand Period is the greater of:
a) the maximum measured load in the billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods.

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the billing period, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) if applicable, the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
Gwen R. Pinson
EFFECTIVE
4/1/2018
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Peak
Weekdays	All Hours	1 P.M. – 7 P.M.
Weekends	All Hours	

All other months of October continuously through April

	Base	Peak
Weekdays	All Hours	6 A.M. – 12 Noon
Weekends	All Hours	

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

KENTUCKY
PUBLIC SERVICE COMMISSION
John Lyons
ACTING EXECUTIVE DIRECTOR
John S. Lyons
EFFECTIVE
7/1/2017
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

AG Exhibit 5

OAG EXHIBIT 5

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF OF PUBLIC CONVENIENCE AND NECESSITY	))))	CASE NO. 2016-00370

ORDER

Kentucky Utilities Company ("KU") is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to consumers in portions of 77 counties in central, northern, southeastern, and western Kentucky.[1] Its most recent general rate increase was granted in Case No. 2014-00371.[2]

BACKGROUND

On October 21, 2016, KU filed a notice of its intent to file an application for approval of an increase in its electric rates based on a forecasted test year ending June 30, 2018. On November 23, 2016, KU filed its application, which included new rates to be effective January 1, 2017, based on a request to increase its electric revenues by $103.1 million, or 6.4 percent per year for the forecasted test period ending June 30, 2018, as compared to the operating revenues for the forecasted test period under existing electric rates.[3] The proposed increase would raise the monthly bill

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[1] *See* KU's Application, ¶ 2 for a list of the counties served.

[2] Case No. 2014-00371, *Application of Kentucky Utilities for an Adjustment of Its Electric Rates* (Ky. PSC June 30, 2015).

[3] Application, ¶ 6.

of an average residential customer by $7.16, or 5.9 percent.[4] The average KU residential customer consumes approximately 1,179 kilowatt-hours ("kWh") of electricity monthly.[5] KU's application included requests for Certificates of Public Convenience and Necessity ("CPCNs") to implement an Advanced Meter System ("AMS") and a Distribution Automation system ("DA"). KU stated that the AMS project would involve replacing approximately 530,000 existing electric meters in its service territory with AMS meters, which have two-way communications and remote service switching capabilities.[6] The estimated capital cost of the AMS project is $138.8 million.[7] The estimated incremental operating and maintenance cost during the deployment phase is approximately $13.7 million.[8] The deployment period was expected to begin in late 2017 and to be completed by the end of 2019.[9] KU also requested authority to establish a regulatory asset for the remaining net book value of the electric meters retired as a result of the proposed AMS project.[10] KU estimated that the amount of this regulatory asset would be approximately $26.9 million.[11] In connection with the proposed AMS project, KU also sought deviations from certain regulations dealing with meter inspections and testing.

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[4] *Id.*, ¶ 7.

[5] *Id.*

[6] *Id.*, ¶ 14.

[7] *Id.*

[8] *Id.*

[9] *Id.*

[10] *Id.*, ¶ 33.

[11] *Id.*

According to KU, the proposed DA project involves the extension of intelligent control over electric power grid functions to the distribution system level.[12] The project will enable KU's distribution system to provide real-time information and allow for remote monitoring, remote control, and automation of distribution line equipment.[13] For both KU and Louisville Gas & Electric Company ("LG&E"), KU's sister company,[14] the total capital cost of the proposed DA project is approximately $112 million.[15] The project will be completed in approximately seven years.[16] Of the total capital expenditure, KU estimated $23 million to be incurred before the end of the forecasted test year on June 30, 2018.[17] KU and LG&E (jointly "Companies") estimated the operations and maintenance ("O&M") expense related to the proposed DA project to be $6 million over the seven-year implementation period, $1.16 million of which will be incurred before the end of the forecasted test year.[18] The DA project will affect approximately 20 percent of the Companies' circuits, 40 percent of the Companies' distribution line miles, and 50 percent of the Companies' customers.[19]

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[12] *Id.*, ¶ 23.

[13] *Id.*

[14] LG&E has also filed a base rate application seeking, among other things, an increase in its electric and gas rates. That application is docketed as Case No. 2016-00371, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity* (Application filed Nov. 23, 2016).

[15] Application, ¶ 30.

[16] *Id.*

[17] *Id.*

[18] *Id.*, ¶ 31.

[19] *Id.*, ¶ 23.

KU estimated that it will receive approximately $861,843 of jurisdictional reservation and termination fees in connection with agreements related to the refined coal production facilities at the Companies' Ghent, Mill Creek, and Trimble County Generating Stations.[20] Pursuant to Case No. 2015-00264,[21] KU has been recording these proceeds as a regulatory liability and it now proposes to amortize this regulatory liability over three years.[22]

Lastly, KU also submitted a depreciation study in support of its application and requests that its proposed depreciation rates be approved.

Pursuant to the Commission's December 13, 2016 Order, KU's new rates, which were proposed to become effective on January 1, 2017, were suspended for six months, up to and including June 30, 2017. The December 13, 2016 Order also established a procedural schedule, which provided for a deadline for filing intervention requests; two rounds of discovery upon KU's application; a deadline for the filing of intervenor testimony; one round of discovery upon any intervenor testimony; and an opportunity for KU to file rebuttal testimony.

The following parties were granted intervention in this proceeding: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kroger Company ("Kroger"); Wal-Mart Stores East, LP and Sam's East, Inc. (jointly "Wal-Mart"); Kentucky School Boards Association ("KSBA"); Kentucky Cable Telecommunications

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[20] *Id.*, ¶ 39.

[21] Case No. 2015-00264, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling* (Ky. PSC Nov. 24, 2015).

[22] Application, ¶ 39.

Association ("KCTA"); Alice Howell, Carl Vogel, and Sierra Club (jointly "Sierra Club"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"); Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"); Lexington-Fayette Urban County Government ("LFUCG"); and Kentucky League of Cities ("KLC").

Informal conferences ("IC") were held at the Commission's offices on April 12, 13, and 17, 2017, which resulted in all of the parties to this matter, with the exception of AT&T and KCTA, reaching a settlement agreement in principle on all issues other than those involving the Companies' proposed Rate PSA – Pole and Structure Attachment Charges.[23] On April 19, 2017, KU and LG&E filed a motion requesting leave to submit the written Stipulation and Recommendation ("First Stipulation") intended to address all of the issues, except for the proposed Rate PSA tariff, in the two respective rate cases. An additional IC was held on April 25, 2017, for the limited purpose of discussing and possibly resolving the issues associated with the Companies' proposed Rate PSA tariff. The Companies, KCTA, and AT&T were able to reach an agreement in principle for the resolution of all material issues pertaining to the proposed Rate PSA tariff. On May 1, 2017, KU and LG&E filed a motion requesting leave to submit the written Second Stipulation and Recommendation ("Second Stipulation"), which addresses all of the issues related to the Companies' proposed Rate PSA tariff.

The Commission held information sessions and public meetings for the purpose of taking public comments on April 11, 2017, in Louisville, Kentucky, at Jefferson Community and Technical College; on April 12, 2017, in Madisonville, Kentucky, at

[23] The informal conferences were jointly held to discuss issues in the instant matter and to discuss issues related to the LG&E rate case, Case No. 2016-00371.

Madisonville Community College; and on April 18, 2017, in Lexington, Kentucky, at the Lexington Public Library – Northside Branch.

A formal hearing was held on May 9, 2017, for the purposes of cross-examination of all witnesses and for the consideration of the two stipulations.[24] Pursuant to a May 3, 2017 Order, the Commission required all of the Companies' employee witnesses as well as the Companies' consultant Steven Seelye, KIUC's witness Stephen Baron, and KSBA's witness Ronald Willhite to be present at the hearing.[25] The May 3, 2017 Order provided the parties to this matter an opportunity to cross-examine any of the other witnesses and, accordingly, directed the parties to the two cases to submit written notice on or before May 5, 2017, setting forth the name of each witness that each party intended to cross-examine at the formal hearing.[26] The May 3, 2017 Order noted that in the absence of a notice identifying witnesses whose attendance was not required by the Commission, the parties would be deemed to have waived cross-examination of those witnesses. None of the parties submitted a notice, and the only witnesses presented for cross-examination were those set forth above as named in the May 3, 2017 Order.

KU filed responses to post-hearing data requests on May 26, 2017, and on June 9, 2017. KSBA filed responses to post-hearing data requests on May 26, 2017. All the parties also filed post-hearing statements indicating they would not object to, or withdraw from, the First Stipulation, regardless whether all schools, including non-public

[24] *See* May 3, 2017 Order at 2.

[25] *Id.* at 3.

[26] *Id.*

schools, are included in the optional pilot program for schools as set forth in Article IV, paragraph 4.11 of the First Stipulation. On May 31, 2017, the AG, Sierra Club, CAC, LFUCG, Metropolitan Housing Coalition ("MHC"), Association of Community Ministries ("ACM"), and Louisville/Jefferson County Metro Government ("Louisville Metro"),[27] filed a joint post-hearing brief in the instant matter and in the LG&E rate case proceeding recommending approval of the Residential Basic Service Charge as set forth in the First Stipulation. On May 31, 2017, KU, KIUC, and Kroger filed their respective post-hearing briefs recommending approval of the First and Second Stipulations. On June 1, 2017, KSBA filed a separate post-hearing brief addressing the legality of the optional pilot school rate tariffs. KU and the AG filed their respective briefs on the pilot school tariff issue on June 2, 2017. KSBA and the AG contend that the school-related pilot tariffs do not violate KRS 278.035 because the proposed tariffs set forth a reasonable classification and would not be preferential, given the unique load characteristics and usage patterns of schools as compared to the other customers in their existing rate classes. The AG also pointed out that all public and private schools have similar load and usage characteristics making them a homogenous group, which made it reasonable to include in the pilot school tariff private schools that might wish to participate. The AG opined that "[a]s long as potential school participants to the pilot electric school tariffs are afforded equal opportunity to participate, the pilot electrical tariffs cannot be said to be 'preferential' within the meaning of KRS 278.035."[28] Similarly, KU contends that the pilot school tariffs do not provide a publicly funded entity an entitlement to service under

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[27] MHC, ACM, and Louisville Metro are parties only to the LG&E rate case, Case No. 2016-00371.

[28] AG's Post-Hearing Brief Regarding School Board Pilot Tariff at 7-8.

that rate, and that the pilot tariffs are a reasonable means of gathering data to determine whether such tariffs should be made generally available service offerings. KSBA, KU, and the AG all indicated that they did not object to modifying the First Stipulation to allow schools not covered by KRS 160.325, i.e., non-public schools, to participate in the pilot tariffs.

FIRST STIPULATION

The First Stipulation reflects the agreement of all of the parties to the two cases, with the exception of KCTA and AT&T, addressing all of the issues not related to pole attachments. A summary of the provisions contained in the First Stipulation is as follows:

- KU agrees to withdraw the CPCN request to implement the AMS project and will initiate an AMS collaborative involving the Companies and all interested parties to these proceedings to discuss any concerns about AMS.[29]
- KU will be issued a CPCN to implement the DA project.
- KU revenue will increase by $54.9 million.
- The stipulated level of revenue associated with the electric operations were adjusted by: 1) removal of AMS cost recovery; 2) reduction of Return on Equity ("ROE") to 9.75 percent; 3) revised depreciation rates; 4) revenues from refined coal agreements at Ghent; 5) updated five-year average for uncollectible debt expense; 6) use of an eight-year average of generator outage expenses, based upon four-years' historical expenses and four-years' forecasted expenses; and 7) adjustment to construction work in progress capital slippage.
- The agreed-to revenue allocation is set forth in Exhibit 4 of the First Stipulation.

[29] Because KU has agreed to withdraw its CPCN request to implement the AMS project, the company is also withdrawing its request to establish a regulatory asset for those electric meters that would have been retired as a result of the AMS project and the requests to deviate from certain regulations governing meter inspections and testing. *See* May 9, 2017 Hearing at 2:22:09.

- The Basic Service Charge will increase to $11.50 effective July 1, 2017, and to $12.25 effective July 1, 2018, for KU and LG&E Electric Rates RS, VFD, RTOD-Energy and RTOD-Demand.

- Current CSR customers may choose between Option A and Option B.

    - Option A reflects the Companies' as-filed proposition.

    - Option B reflects the following modifications to the existing CSR tariff:
        - credits for both Companies of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission);

        - KU may request physical curtailment when more than ten of the utility's primary combustion turbines ("CTs") are being dispatched, irrespective of whether the utility is making off-system sales. A CSR customer may avoid a physical curtailment by buying through at the Automatic Buy-Through Price.

- KU and LG&E agree to add a voluntary sports-field-lighting rate schedule, Pilot OSL – Outdoor Sports Lighting Service, on a pilot basis limited to 20 participants per company and will utilize a time-of-day rate structure.

- KU and LG&E agree not to split their residential and general service electric energy charges into Infrastructure and Variable components as proposed.

- KU and LG&E agree to file a study in their next rate cases regarding the impacts of 100 percent base demand ratchets for Rate TODS.

- For customers with their own generation, for 60 minutes following a utility-system fault, KU and LG&E agree to not use any demand data for a Rate TODP customer to set billing demand.

- KU and LG&E agree to add an optional pilot tariff for schools subject to KRS 160.325. The Companies' pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for each company, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served.

- KU and LG&E agree to file an application no later than December 31, 2017, proposing a two-year extension of the School Energy Managers Program (from July 1, 2018, through June 30, 2020) with a proposed total annual level of funding of $725,000.

- KU and LG&E agree to fund a study concerning economical deployment of electric bus infrastructure in the Lexington area, as well as cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

- KU and LG&E agree to establish an LED Lighting Collaborative involving Louisville Metro, LFUCG, and any other interested parties to these proceedings.

- KU agrees to increase its monthly residential Home Energy Assistance ("HEA") charge from $0.25 per month to $0.30 per month, which will remain effective through June 30, 2021.

- KU and LG&E agree to commit to contribute a total of $1.45 million of shareholder funds per year, which will remain in effect through June 30, 2021. These shareholder funds will be applied as follows:

  - From KU, $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs. KU agrees that up to 10 percent of its total contributions to CAC may be used for reasonable administrative expenses.

  - From LG&E, $700,000 to ACM for utility assistance and $180,000 for HEA. LG&E agrees that up to 10 percent of its total contributions to ACM may be used for reasonable administrative expenses.

The First Stipulation results in the monthly bill of an average KU residential customer increasing by $4.20, or 3.49 percent. A summary of the impact of the First Stipulation on KU's revenue requirement is as follows.

- **Electric Operations**. The parties agreed in the First Stipulation to reduce KU's requested revenue increase from $103.1 million to $54.9 million. The adjustments to KU's requested revenue requirement are discussed further below.

  A. Advanced Metering System. As previously discussed, KU requested that the Commission grant a CPCN to install AMS in its service territory. As part of the First Stipulation, the Companies agreed to withdraw their requests for the CPCN and to establish a collaborative to discuss the parties' concerns and seek to address them. In the test year, the cumulative effect of the withdrawal of the CPCN on the revenue requirement of KU is a reduction of $6.3 million.

B. Return on Equity. The agreement to reduce the ROE to 9.75 percent results in a decrease to KU's revenue requirement of $15.3 million.

C. Depreciation. KU proposed to revise its depreciation rates based upon depreciation studies that were performed by John Spanos of the firm Gannett Fleming Valuation and Rate Consultants, LLC. The parties to the First Stipulation agreed to revise KU's proposed depreciation rates resulting in a revenue-requirement reduction of $14.7 million. The revised depreciation rates will also reduce KU's environmental cost recovery revenue requirement by $19.1 million. The impact will be included in the environmental cost recovery filing made for the July 2017 expense month.

D. KU Refined Coal Revenues. The First Stipulation reflects a $9.1 million reduction in KU's revenue requirement related to KU's contract proceeds from the Refined Coal project at the Ghent Generating Station.

E. Uncollectibles Expense. KU proposed to use uncollectible factors based on using a five-year average of write-offs to revenues for the period 2011 through 2015. The First Stipulation uses an updated five-year period, 2012 through 2016, to reduce KU's revenue requirement by $0.5 million.

F. Normalize Generation Outage. KU proposed $90.201 million in generation outage expense for the test year, which exceeded its five-year average of $77.384 million. In the First Stipulation, the parties agreed to use an eight-year average expense, four years of historical expenses, and four years of forecasted expenses. This approach reduces KU's revenue requirement by $1.6 million.

G. Construction Work in Progress Capital Slippage. The First Stipulation reflects a slippage factor to eliminate over estimation in construction budgeting. The slippage factor reduces KU's requested revenue requirement by $0.7 million.

- **Stipulation Summary**. The table below reflects the impact each Stipulation adjustment has on KU.

	KU
Proposed Revenue Requirement	$ 103.1 million
Remove AMS	(6.3) million
9.75% Return on Equity	(15.3) million
Revised Depreciation Rates	(14.7) million
KU Refined Coal Revenues	(9.1) million
Uncollectible Expense	(0.5) million
Generator Outage Expenses	(1.6) million
CWIP Capital Slippage	(0.7) million
Stipulated Revenue Requirements	$ 54.9 million

SECOND STIPULATION

The Second Stipulation reflects the agreement of KU, AT&T, and KCTA as to the terms and conditions of KU's pole and structure attachment charges contained in Tariff PSA. The major substantive areas addressed in the Second Stipulation are as follows:

- Agreement on KU's attachment charges for pole-top wireless facilities;[30]
- Agreement on KU's attachment charges for mid-pole wireless facilities;[31]
- Amendment of the terms and conditions set forth in KU's proposed Tariff PSA rate schedule.[32]

ANALYSIS AND FINDINGS

The Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just, and reasonable."[33] While numerous intervenors with significant experience in rate proceedings and collectively

[30] Second Stipulation, paragraph 1.2.

[31] *Id.* at paragraph 1.3.

[32] *Id.* at paragraph 1.4.

[33] KRS 278.030(1).

representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes fair, just, and reasonable rates. The Commission must review the record, including the two stipulations, and apply its expertise to make an independent decision as to the level of rates, including terms and conditions of service, that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed its traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE.

FIRST STIPULATION

Based upon its review of the First Stipulation, the attachments thereto, and the case record including intervenor testimony, the Commission finds that, with the modifications discussed below, the First Stipulation is reasonable and in the public interest. With those modifications, the Commission finds that the First Stipulation was the product of arm's-length negotiations among knowledgeable, capable parties and should be approved. Such approval is based solely on the reasonableness of the modified First Stipulation and does not constitute a precedent on any individual issue.

Employee Retirement Plans

KU maintains a Defined Dollar Benefit Retirement Plan for those employees hired prior to January 1, 2006 ("Pre 2006 DDB Plan").[34] This plan was closed to new participants and was replaced with a Retirement Income Account ("401(k) Plan") for

[34] See KU's response to Commission Staff's Fourth Request for Information ("Staff's Fourth Request"), Item 6.

those employees hired after January 1, 2006.[35] All employees that were hired prior to January 1, 2006, are eligible to participate in both the Pre 2006 DDB Plan and the 401(k) Plan.[36] KU contributes 100 percent of the Pre 2006 DDB Plan costs.[37] KU also contributes to the 401(k) Plan between 3 percent to 7 percent[38] of eligible employee compensation and $0.70 per dollar match for employee contributions up to 6 percent of the employee's eligible contribution.[39]

The Commission finds that, for ratemaking purposes, it is not reasonable to include both KU's Pre 2006 DDB plan contributions and KU's matching contributions to the 401(k) Plan for the following employee categories: exempt, manager, non-exempt, and officer and director personnel. The Commission chooses not to address similar 401(k) Plan company matching contributions for hourly and bargaining unit employees in this proceeding, as it is not within the Commission's authority to negotiate or modify bargaining agreements. The Commission will not make a distinction between represented and non-represented hourly groups at this time, but will instead provide an opportunity for KU to address these excessive costs for both employee classes prior to its next base rate case, as rate recovery of these contributions will be evaluated for appropriateness as part of its next base rate case. Employees participating in the Pre

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[35] Refer to KU's response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 11. Although throughout this proceeding, KU made references to two separate post-2016 retirement plans, the Retirement Income Account and the 401(k) Savings Plan, they are actually the same plan.

[36] *Id.*

[37] Response to Staff's Fourth Request, Item 6.

[38] The percentage contribution rate depends on the employee's years of service as of January 1 of that year.

[39] Response to Staff's Fourth Request, Item 6.

2006 DDB Plan enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts excessive for ratemaking purposes. Accordingly, the Commission denies for recovery 401(k) Plan matching contributions in the amount of $1,720,383 before gross-up.

Return on Equity

In its application, KU developed its ROE using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), the utility risk premium ("RP"), and the expected earnings approach.[40] Based on the results of the methods employed in its analysis, KU recommended an ROE range for its electric operations of 9.63 percent to 10.83 percent, including flotation cost.[41] KU recommended awarding the midpoint of this range, 10.23 percent, to maintain financial integrity, support additional capital investment and recognize flotation costs.[42] Direct testimony regarding ROE was provided by the AG and KIUC, and was subject to discovery by the Commission Staff and all parties.[43] Per paragraphs 2.2(B) and 3.2(B) of the First Stipulation, KU and the intervenors agreed that a ROE of 9.75 percent is reasonable for KU's electric operations.[44] The following table presents the recommended ROEs from KU and the interveners and the methods used to support each parties' findings:

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[40] Direct Testimony of Adrien M. McKenzie, CFA ("McKenzie Direct Testimony"), at 2.

[41] *Id.*, Exhibit No. 2, page 1 of 1.

[42] *Id.*, at 5–6.

[43] Walmart did not provide an ROE analysis, but pointed out that KU's proposed ROE was higher than natural trends, and that average ROE awards of vertically integrated utilities in 2015 and 2016 was 9.76 percent.

[44] First Stipulation, at 5 and 9.

Party	Recommendation	Methods
KU	10.23%	DCF, CAPM, ECAPM, RP
AG[45]	8.75%	DCF, CAPM
KIUC[46]	9.0%	DCF, CAPM
FIRST STIPULATION	**9.75%**	

In the First Stipulation, all parties agreed that the revenue requirement increases for KU's electric operations will reflect a 9.75 percent ROE as applied to KU's capitalization and capital structure of the proposed electric revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced KU's proposed electric revenue requirement by $15.3 million.[47] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable and higher than required by investors in today's economic climate, and that this provision of the First Stipulation should be modified.

While the Commission does not rely on individual returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities, the Commission does find it reasonable to expect that other state commissions, each with its own attributes, evaluate expert witness testimony which uses the same or similar cost-of-equity models as those presented by the parties participating in this rate proceeding, and reach conclusions based on the data provided in the records of individual cases. The Regulatory Research Associates ("RRA") reports introduced into the record of this

[45] Direct Testimony of Dr. J. Randall Woolridge at 67.

[46] Direct Testimony of Richard Baudino at 28.

[47] First Stipulation at 5.

proceeding[48] summarize the conclusions reached by state utility regulatory commissions, including this Commission, with regard to reasonable ROEs and contain explanatory reference points as to individual circumstances, all of which are available to investors. To the extent that investors' expectations are influenced by such publications, and we believe they are, we also find it appropriate to use that information to put their expectations in context. In fact, in KU's rebuttal testimony, KU agreed that allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost-of-equity analysis.[49]

The Commission takes notes of the fact that average annual ROE awards by state public service commissions for the last two years have ranged from 9.23 percent to 10.55 percent.[50] Furthermore, the average authorized ROEs reported by RRA for the fourth quarter of 2016 was 9.6 percent.[51] Authorized ROE data reported to investors by The Value Line Investment Survey for the specific firms in KU's proxy group indicates that state-allowed ROEs for those utilities were in a range of reasonableness of 9.00 to 12.50 percent.[52]

In 2017, the economic environment has shown signs of relative improvement. In response to increased economic growth and low unemployment, the Federal Reserve increased interest rates in March and June 2017, and current outlooks, including comments from government agencies, show that investors anticipate additional interest

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[48] *See* Rebuttal Testimony of Adrien M. McKenzie, CFA, at 11.

[49] *Id.* at 10.

[50] *Id.*, Exhibit 12.

[51] *Id.* at 13.

[52] *Id.*, Exhibit 13.

rate increases.[53] KU's own model produces an ROE, less flotation costs and adjustments, to be in the range of 9.5 percent to 10.7 percent.[54] Even with the current uptick in economic conditions, the economy remains in an era of historically low interest rates and slow economic growth. Therefore, irrespective of the agreement by the parties that a 9.75 percent ROE is appropriate for KU, the Commission finds that a slightly lower ROE is a better reflection of current economic conditions and investor expectations. Based on the entire record developed in this proceeding, we find that KU's required ROE falls within a range of 9.20 percent to 10.20 percent with a midpoint of 9.70 percent. An ROE of 9.70 should be used for the purpose of base rate revenues and certain tariffs, as discussed later in this Order.

This revision to the First Stipulation reduces KU's net operating income before income taxes by $969,324.

Revenue Requirement

As discussed above, the Commission finds the First Stipulation to be reasonable only by eliminating KU's 401(k) Plan contributions for the following employee categories: exempt, manager, non-exempt and officer and director personnel, and by reducing the ROE from 9.75 percent to 9.70 percent. These modifications decrease the stipulated revenue requirement from $54,900,000 to $50,484,652 a decrease of $4,415,348, as calculated in the table below.

[53] *Id.* at 8.

[54] McKenzie Direct Testimony, Exhibit No. 2.

	KU
KU's 401(k) Plan	$ (1,720,383)
ROE from 9.75% to 9.7%	(969,324)
Impact to Net Operating Income Before Taxes	(2,689,707)
Multiplied by: Gross up Factor	1.641572
Revenue Requirement Impact	(4,415,348)
Increase per Stipulation	54,900,000
Net Increase Granted by the Commission	$ 50,484,652

Residential Basic Service Charge

The Commission believes an increase to the Residential Basic Service Charge is warranted, and we find the level of the Year 2 charge to be reasonable. We further find that the two-step increase to $11.50 in Year 1 and to $12.25 in Year 2 is unnecessary. The total increase in the Residential Basic Service Charge of $1.50 is a modest increase from the current level, and the Commission sees no reason to complicate the issue by using a two-step method, which could generate confusion among KU's residential customers. The First Stipulation is therefore modified with respect to the Residential Basic Service Charge, and the Year 2 charge of $12.25 should be approved for service rendered on and after July 1, 2017.

Optional Pilot Rates for Schools Subject to KRS 160.325

At the formal hearing in this matter, the parties were requested to file post-hearing briefs concerning the legality of the proposed school-related pilot rate tariffs, Rates SPS and STOD, with respect to the applicability of KRS 278.035, and to indicate whether they would object to the modification of the First Stipulation to include schools not covered by KRS 160.325. Briefs submitted by KSBA, KU, and the AG acknowledged that the inclusion of non-public schools in the pilot tariffs would avoid a possible violation of KRS 278.035. All parties to this proceeding submitted statements indicating that they had no objection to modification of the First Stipulation to include non-public schools in the pilots.

The Commission finds that the First Stipulation should be modified to include schools not covered by KRS 160.325. The inclusion of non-public schools would rectify any potential conflict with KRS 278.035 and would remove any element of preferential treatment of public schools that could be associated with the pilot tariffs. As previously stated, the pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for KU, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. The Commission notes that the parties to this proceeding agreed that the other ratepayers would assume the revenue shortfall resulting from the lower rates set forth in the pilot school tariffs. Therefore, the Commission will place a limit on the amount of time the pilot tariffs will be in effect and finds that the pilot tariffs should be effective for three years, or until KU files its next rate case, whichever is earlier. In the event that new base rates are not in effect by July 1, 2020, schools participating in the pilot tariffs should be returned to the tariffs under which they were formerly served. In addition, the Commission finds that KU should create a regulatory liability to record the difference between what the schools served under the pilot tariffs would have been billed under the pilot tariffs subsequent to July 1, 2020, and the amounts they are billed under the tariffs to which they are returned. The regulatory liability will be addressed in KU's next base rate proceeding. We further find that, within

30 days of the date of this Order, KSBA should file with the Commission the process by which KSBA will notify and select those schools, both public and non-public, that would be eligible to participate in the pilot tariffs.

With regard to the data gathered from the schools participating in the pilot tariffs, the Commission finds that KU should file reports with the Commission, beginning six months from the date of this Order and every six months thereafter, which set out details concerning monthly load information, individually and in the aggregate, and indicating preliminary findings as conclusions regarding the schools' load characteristics are reached. In the event that a future proposal is made either to extend the pilot school tariffs or to make them permanent, this load information will be used to determine whether the schools' load characteristics justify a special rate classification.

Collaborative Study Regarding Electric Buses

Although this provision will be funded by shareholder contributions and the Commission does not oppose it, this type of provision pertaining to an unrelated business transaction should be negotiated separately between the individual parties and has no bearing on KU's rates as found reasonable herein based on the record of this case. It is therefore superfluous to this regulatory proceeding, contributes nothing to the reasonableness of the First Stipulation, and should be omitted from future ratemaking proceedings.

LED Lighting and Electric Bus Study Collaboratives

Pursuant to the provisions of the First Stipulation, KU commits to engage in good faith with Louisville Metro, LFUCG, and any other interested parties to this proceeding and the LG&E rate proceeding in a collaborative to discuss issues related to LED lighting and electric bus infrastructure and rates. While the provisions limit participation to only those parties to the instant rate proceeding and the LG&E rate proceeding, the Commission finds that the collaboratives should also include the Kentucky Department of Energy Development and Independence, whose mission includes creating efficient, sustainable energy solutions and strategies.

SECOND STIPULATION

As mentioned previously, KU proposed certain changes to its pole attachment tariff in its application. KU currently offers the use of spaces on its poles for cable television attachments under Tariff CTAC, Cable Television Attachment Charges ("Tariff CTAC"). KU proposed to rename Tariff CTAC to Tariff PSA, Pole and Structure Attachment Charges ("Tariff PSA"), and to expand the tariff to include telecommunications wireline and wireless facilities' attachments, which are not currently covered under Tariff CTAC. KU also proposed to modify the rates, terms, and conditions of service for attaching wireline and wireless facilities to its poles.

The Second Stipulation includes the modifications proposed in the application, but also includes additional changes in the rates for pole space use and conditions of service for the placement of an attachment on KU's poles. As originally proposed, the Tariff PSA's rate schedule contained three charges: 1) an annual charge of $7.25 for each wireline pole attachment; 2) an annual charge of $0.81 for each linear foot of duct; and 3) an annual charge of $84.00 for each wireless facility attachment. AT&T and KCTA did not object to the charge for wireline and duct attachments, but did object to the annual charge for wireless facility attachments. KU estimated that wireless facilities occupy an average of 11.5 feet on its poles, and calculated the $84.00 wireless facility attachment charge based on the use of 11.5 feet of pole space at $7.25[55] per foot of pole. AT&T and KCTA did not challenge the $7.25 per foot factor in the calculation, but argued that wireless facility attachments occupy far less pole space. The Second Stipulation provides for a charge of $36.25, based upon a wireless facility attached to the top of a pole using five feet of the pole—one foot for the antenna and four feet of clearance above the power space to maintain a safe working distance between the electric facilities on the pole and the pole top antenna. The Second Stipulation also provides for rates for wireless facilities located mid-pole to be established on a case-by-case basis through special contracts. This provision is based upon the lack of requests for mid-pole wireless facilities, which resulted in a lack of evidence upon which to base a uniform rate for mid-pole wireless facilities.

Another modification is the requirement for a pole-loading study. As originally proposed, Tariff PSA required that a pole-loading study be submitted with each application as a safety and reliability measure. KCTA argued that requiring pole-loading studies for every application provides no appreciable safety or reliability benefit to KU, while unnecessarily increasing construction costs and preventing timely deployment of wireless facilities. The Second Stipulation provides that an attachment applicant may include a pole-load study with the application or, in the alternative, assert that a pole's condition does not warrant the need for a pole-loading study. To confirm the assertion, KU may perform a visual inspection of the pole to which the facility is proposed to be attached. If KU determines that a pole-loading study is needed, the attachment applicant has the option of conducting the pole-loading study itself or requesting that KU

[55] The Commission approved the rate of $7.25 per foot in Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric and Rates* (Ky. PSC June 30, 2015).

perform the study. The attachment applicant is responsible for the costs of any visual inspection or pole-loading study that KU performs. KU contends that the proposed revision to Tariff PSA does not sacrifice safety or system reliability.

The Commission finds that the proposed Tariff PSA with the modifications agreed to in the Second Stipulation is reasonable and that the Second Stipulation should be approved in its entirety.

OTHER ISSUES

Rate Adjustment

In setting the rates shown in Appendix B, the Commission maintained the basic service charges for each class that were included in the First Stipulation, with the exception that the Year 1 Residential Basic Service Charge was not approved as previously discussed, and is therefore not included. The reduction in KU's stipulated revenue increase as found reasonable herein was allocated to the energy charges of those customer classes for which revenue increases were proposed in the First Stipulation. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the First Stipulation.

Electric Vehicle Supply Equipment Calculation

In response to a Post-Hearing Request for Information, KU provided a revised sheet showing the impact on the Electric Vehicle Supply Equipment ("EVSE"), Electric Vehicle Charging Service ("EVC"), and Electric Vehicle Supply Equipment ("EVSE-R") rates of using the 9.75 percent ROE in the capital structure. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the EVSE rates should be further revised to reflect the approved ROE. The Commission also finds that since the

EVSE, EVC, and EVSE-R rates are based, in part, on the General Service ("GS") energy rate, the rates should be updated for the change in the GS energy rate approved with this Order. The EVSE, EVC, and EVSE-R rates set out in Appendix B to this Order reflect both revisions.

Solar Capacity Charge and Solar Energy Credits

In response to a Post-Hearing Request for Information, KU provided a revised sheet showing the impact on the Solar Capacity Charge and Solar Energy Credits of using the 9.75 percent ROE in the capital structure and under each of the corrected cost-of-service studies filed by KU in this proceeding. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the Solar Capacity Charge and Solar Energy Credits should be further revised to reflect the approved ROE. The Commission also finds that the Solar Energy Credits should be revised for Rate Schedules RS, VFD, RTOD-E, RTOD-D, AES, and GS using the average of the amounts provided in response to the post-hearing information request,[56] but revised for the change in ROE and using the energy rates approved herein for Rate Schedules PS, TODS, and TODP. The rates set out in Appendix B to this Order reflect the revisions.

Demand-Side Management ("DSM")

In response to a Commission Staff Information Request, KU stated that upon the implementation of new base rates, the DSM Revenue from Lost Sales component of its DSM cost-recovery mechanism would change to zero.[57] The Commission finds that

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[56] Response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 6, Attachment KU-6-1 and Attachment KU-6-2.

[57] KU's response to Commission Staff's Second Request for Information, Item 10.

KU's compliance tariff that it is directed to file in ordering paragraph 10 should reflect this revision to its DSM cost-recovery mechanism.

Loss of Municipal Load

The Commission takes notice that nine municipal utilities will be terminating their wholesale power contracts with KU effective, at the latest, April 30, 2019.[58] The combined load of those nine departing wholesale customers is approximately 325 megawatts ("MW").[59] At the formal hearing, Victor Staffieri, KU's Chairman, Chief Executive Officer, and President, testified that KU had not secured new customers to purchase the generation that would be available when the nine municipal utilities terminate their contracts with KU, but that the company would take into account any growth in load as potential replacement for the loss of municipal load.[60] Mr. Staffieri also stated that it is not known what impact the loss of municipal load would have on KU's rates when the company files its next rate case.[61] David Sinclair, KU's Vice President, Energy Supply and Analysis, also testified at the formal hearing that, beginning in 2019 and 2020, KU would have a reserve margin of approximately 24 percent, which would be above the upper end of KU's target reserve margin range.[62]

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[58] *See* Case No. 2014-0002, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station* (Ky. PSC Dec. 19, 2014), final Order at 2–3.

[59] The nine municipal wholesale customers are Barbourville, Bardwell, Berea, Corbin, Falmouth, Frankfort, Madisonville, Paris, and Providence.

[60] May 9, 2017 Hearing at 1:37:37.

[61] *Id.* at 1:38:40.

[62] May 10, 2017 Hearing at 9:37:30.

In light of the significant loss of load in connection with the nine municipal customers' leaving KU's system in April 2019, the Commission finds that KU should develop and implement a formal plan to address how KU will mitigate the loss of the approximately 325 MW municipal load, including, but not limited to, how KU will market the excess capacity and energy resulting from the municipals departing the system, the types of measures KU will implement to attract new or expanding load, and whether joining a regional transmission organization would be beneficial in its efforts to market the excess capacity and energy.

Transmission System Improvement Plan

KU is currently implementing a Transmission System Improvement Plan ("Transmission Plan") aimed at reducing outage occurrence and duration and improving overall reliability of service to its customers.[63] KU states that the Transmission Plan contains two primary categories of investment: system integrity and reliability.[64] System integrity involves replacement of aging transmission assets to enhance reliability.[65] The reliability component involves several maintenance programs and capital investment in line sectionalization.[66] KU will spend approximately $149 million between the end of the last base-rate-case test period and the end of the forecasted test period (July 1, 2016 – June 30, 2018) on its Transmission Plan.[67] This spending is part of a total of $511

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[63] Direct Testimony of Paul W. Thompson ("Thompson Testimony") at 25.

[64] *Id.* at 26.

[65] *Id.*

[66] *Id.*

[67] *Id.* at 27.

million in transmission capital investments that KU and LG&E project to spend over the five-year period beginning 2017.[68]

In light of the significant investments that KU intends to make pursuant to the Transmission Plan, the Commission will require KU to file annual reports, over the five-year Transmission Plan period, detailing the progress on the spend out for the reporting period, the criteria utilized by KU to prioritize the various transmission projects, the impact on reliability or other benefits to KU's customers resulting from such investments, and outlining the expenditures for the following year.

<u>KU's Tariffs</u>

Commission regulation 807 KAR 5:011, Section 4(1), requires each utility to include an accurate index of the city, town, village, or district in which its rates are applicable. The first page of KU's tariffs references its service as being available "[i]n seventy-seven counties in the Commonwealth of Kentucky as depicted on territorial maps as filed with the Public Service Commission of Kentucky." Because those maps are not readily available to members of the public, KU should revise its tariffs to include a list of the communities in which it serves.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by KU are denied.

2. KU's motions for leave to file the First and Second Stipulations are granted.

3. The First and Second Stipulations, attached hereto as Appendix A, (without exhibits) are approved with the modifications discussed herein.

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[68] *Id.* at 26–27.

4. The rates and charges in Appendix B, attached hereto, are fair, just, and reasonable for KU to charge for service rendered on and after July 1, 2017.

5. KU is granted a CPCN to implement the DA project as described in the application.

6. Within 30 days of the date of this Order, KSBA shall file with the Commission the process by which it will notify and select those schools that are eligible to participate in the pilot tariffs approved herein.

7. KU shall file reports with the Commission as directed herein which set out details concerning the pilot school tariffs study.

8. Within 90 days of the date of this Order, KU shall file a formal plan addressing how KU will mitigate the loss of the approximately 325 MW municipal load as discussed herein.

9. Beginning June 1, 2018, and continuing over the five-year Transmission Plan period, KU shall file an annual Transmission Plan report as discussed herein.

10. Within 20 days of the date of this Order, KU shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised tariffs, including an index of communities served, as set forth in this Order reflecting that they were approved pursuant to this Order.

11. Any document filed pursuant to ordering paragraphs 6, 7, 8, and 9 of this Order shall reference the number of this case and shall be retained in the utility's general correspondence file.

12. The Executive Director is delegated authority to grant reasonable extension of time for the filing of any documents required by ordering paragraphs 6, 7, 8, and 9 of this Order upon KU's showing of good cause for such extension.

By the Commission

ENTERED
JUN 22 2017
KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Talina R. Mathews

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00370 DATED JUN 2 2 2017

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into this 19th day of April 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Association of Community Ministries, Inc. ("ACM"); Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); United States Department of Defense and All Other Federal Executive Agencies ("DoD"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky League of Cities ("KLC"); The Kroger Company ("Kroger"); Kentucky School Boards Association ("KSBA"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Metropolitan Housing Coalition ("MHC"); Sierra Club, Alice Howell, Carl Vogel and Amy Waters (collectively "Sierra Club"); JBS Swift & Co. ("Swift"); and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart"). (Collectively, the Utilities, ACM, AG, CAC, DoD, KIUC, KLC, Kroger, KSBA, LFUCG, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the AG, BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), CAC, Kentucky Cable Telecommunications Association ("KCTA"), KIUC, KLC, Kroger, KSBA, LFUCG, Sierra Club, and Wal-Mart;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to ACM, AG, AT&T, DoD, KCTA, KIUC, Kroger, KSBA, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings, notwithstanding that neither AT&T nor KCTA has agreed with, or entered into, this Stipulation, and therefore neither AT&T nor KCTA is one of the Parties as defined herein;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Stipulation;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. <u>ADVANCED METERING SYSTEMS</u>

1.1. Withdrawing Request for Certificates of Public Convenience and Necessity and Cost Recovery for Advanced Metering Systems. The Utilities agree to withdraw their requests for the Commission to grant certificates of public convenience and necessity ("CPCNs") and to approve cost recovery in these base rate proceedings for the Utilities' proposed full deployment of Advanced Metering Systems ("AMS"). The Parties agree that the Utilities' withdrawal of their requests for CPCNs and cost recovery for AMS in these proceedings does not preclude the Utilities from having full AMS deployment considered in future proceedings.

1.2. AMS Collaborative. The Parties agree that the Utilities and all interested Parties will participate in an AMS Collaborative to discuss the Parties' concerns about AMS and to seek to address them. The AMS Collaborative will begin at a mutually agreeable time after these proceedings conclude and will include only those Parties to these proceedings interested in participating in the collaborative. The Parties agree to engage in the collaborative in good faith not to exceed 15 months from the date the Commission issues orders in these proceedings.

ARTICLE II. <u>ELECTRIC REVENUE REQUIREMENTS</u>

2.1. Utilities' Electric Revenue Requirements. The Parties stipulate that the following increases in annual revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the Rate Proceedings, are fair, just and reasonable for the Parties and for all electric customers of LG&E and KU:

LG&E Electric Operations: $59,400,000.

KU Operations: $54,900,000.

The Parties agree that any increase in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2017.

2.2. Items Reflected in Stipulated Electric Revenue Requirement Increases. The Parties agree that the stipulated electric revenue requirement increases were calculated by beginning with the Utilities' electric revenue requirement increases as presented and supported by the Utilities in their applications in these proceedings and as revised through discovery ($103.1 million for KU; $94.1 million for LG&E electric) and adjusting them by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from the Utilities' electric revenue requirements. This reduces KU's proposed electric revenue requirement increase by $6.3 million, consisting of $3.2 million of operations and maintenance ("O&M") cost and $3.1 million of carrying cost and depreciation expense. Similarly, this reduces LG&E's proposed electric revenue requirement increase by $5.2 million, consisting of $3.0 million of O&M cost and $2.2 million of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for the Utilities' electric operations, and the agreed stipulated revenue requirement increases for the Utilities' electric operations reflect that return on equity as applied to the Utilities' capitalizations and capital structures underlying their originally proposed electric revenue requirement increases as modified through discovery. Use of a 9.75% return on equity reduces the Utilities' proposed electric revenue requirement increases by $15.3 million for KU and $10.1 million for LG&E.

(C) **Revised Depreciation Rates.** The stipulated revenue requirement increases reflect the revised depreciation rates shown in Stipulation Exhibits 1 (KU) and 2 (LG&E electric), which reduce the Utilities' proposed electric revenue requirement increases by $14.7 million for KU and $10.1 million for LG&E. In addition to contributing to reducing the Utilities' proposed electric revenue requirement increases in these proceedings, these revised depreciation rates will reduce environmental cost recovery ("ECR") revenue requirements by $19.1 million for KU and $16.8 million for LG&E relative to the Utilities' proposed depreciation rates as will be included in the ECR mechanism filings beginning with the July 2017 expense month.

(D) **KU Revenues Resulting from the Refined Coal Project at the Ghent Generating Station.** The stipulated revenue requirement increase for KU reflects a $9.1 million revenue-requirement reduction related to KU's contract proceeds resulting from KU's Refined Coal project at the Ghent Generating Station. KU discussed this issue at an Informal Conference held at the Commission on March 14, 2017, in the context of Case No. 2015-00264.

(E) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated electric revenue requirement increases reflect the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average (2011-2015) that was available at the time the Utilities filed their applications in these proceedings. This approach reduces the Utilities' proposed electric revenue requirement increases by $0.5 million for KU and $0.3 million for LG&E.

(F) **Eight-Year Average for Generator Outage Expenses; Related Use of Regulatory Accounting.** The Parties agree to use an eight-year average of generator outage expenses in the Utilities' stipulated electric revenue requirement increases, where the average is of four historical years' expenses (2013-2016) and four years' forecasted expenses (2017-2020). This approach reduces the Utilities' proposed electric revenue requirement increases by $1.6 million for KU and $8.5 million for LG&E. Relatedly, the Parties agree to, and ask the Commission to approve, the Utilities' use of regulatory asset and liability accounting related to generator outage expenses that are greater or less than the eight-year average of the Utilities' generator outage expenses. This regulatory accounting will ensure the Utilities may collect, or will have to return to customers, through future base rates any amounts that are above or below the eight-year average embedded in the stipulated electric revenue requirement increases in these proceedings.

(G) **Adjustment Related to Construction Work in Progress Capital.** The Parties agree to adjust the Utilities' proposed electric revenue requirement increases to reflect differences ("slippage") between past projected and historical capital amounts for construction work in progress ("CWIP"). This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.7 million for KU and $0.4 million for LG&E.

(This space intentionally left blank.)

2.3. Summary Calculation of Electric Revenue Requirement Increases. The table below shows the calculation of the stipulated electric revenue requirement increases:

Item	KU	LG&E
Proposed electric revenue requirement increases	$103.1 million	$94.1 million
Remove AMS	($6.3 million)	($5.2 million)
9.75% return on equity	($15.3 million)	($10.1 million)
Revised depreciation rates	($14.7 million)	($10.1 million)
KU Refined Coal revenues	($9.1 million)	n/a
5-year average uncollectible expense	($0.5 million)	($0.3 million)
8-year average generator outage expense	($1.6 million)	($8.5 million)
CWIP capital slippage	($0.7 million)	($0.4 million)
Stipulated electric revenue requirement increases	$54.9 million	$59.4 million[1]

ARTICLE III. GAS REVENUE REQUIREMENT

3.1. LG&E Gas Revenue Requirement. The Parties stipulate and agree that, effective for service rendered on and after July 1, 2017, an increase in annual revenues for LG&E gas operations of $7,500,000, for purposes of determining the rates of LG&E gas operations in the Rate Proceedings, is fair, just and reasonable for the Parties and for all gas customers of LG&E.

[1] Stipulated LG&E electric revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

3.2. Items Reflected in Stipulated Gas Revenue Requirement Increase. The Parties agree that the stipulated gas revenue requirement was calculated by beginning with LG&E's gas revenue requirement increase as presented and supported by LG&E in its application in Case No. 2016-00371 and as revised through discovery ($13.4 million) and adjusting the proposed gas revenue requirement increase by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from LG&E's gas revenue requirement. This reduces LG&E's proposed gas revenue requirement increase by $0.7 million, consisting solely of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for LG&E's gas operations, and the agreed stipulated revenue requirement increase for LG&E's gas operations reflect that return on equity as applied to LG&E's gas capitalization and capital structure underlying its originally proposed gas revenue requirement increase as modified through discovery. Use of a 9.75% return on equity reduces LG&E's proposed gas revenue requirement increase by $2.9 million.

(C) **Depreciation Rates.** The stipulated gas revenue requirement increase reflects the depreciation rates shown in Stipulation Exhibit 3, which reduce LG&E's proposed gas revenue requirement increase by $2.1 million.

(D) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated gas revenue requirements increase reflects the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average

(2011-2015) that was available at the time LG&E filed its application in Case No. 2016-00371. This approach reduces LG&E's proposed gas revenue requirement increase by $0.1 million.

3.3. Summary Calculation of Gas Revenue Requirement Increase. The table below shows the calculation of the stipulated gas revenue requirement increase:

Item	LG&E Gas
Proposed gas revenue requirement increase	$13.4 million
Remove AMS	($0.7 million)
9.75% return on equity	($2.9 million)
Revised depreciation rates	($2.1 million)
5-year average uncollectible expense	($0.1 million)
Stipulated gas revenue requirement increase	$7.5 million[2]

ARTICLE IV. REVENUE ALLOCATION AND RATE DESIGN

4.1. Revenue Allocation. The Parties hereto agree that the allocations of the increases in annual revenues for KU and LG&E electric operations, and that the allocation of the increase in annual revenue for LG&E gas operations, as set forth on the allocation schedules designated Stipulation Exhibit 4 (KU), Stipulation Exhibit 5 (LG&E electric), and Stipulation Exhibit 6 (LG&E gas) attached hereto, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU.

4.2. Tariff Sheets. The Parties hereto agree that, effective July 1, 2017, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 7

[2] Stipulated gas revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

(KU), Stipulation Exhibit 8 (LG&E electric), and Stipulation Exhibit 9 (LG&E gas) attached hereto, which rates the Parties unanimously stipulate are fair, just, and reasonable, and should be approved by the Commission.

4.3. **Basic Service Charges.** The Parties agree that the following monthly basic service charge amounts shall be implemented on the schedule shown:

Rates	Effective July 1, 2017	Effective July 1, 2018
LG&E and KU Rates RS, VFD, RTOD-Energy, and RTOD-Demand	$11.50	$12.25
LG&E Rates RGS and VFD	$16.35	$16.35

All other basic service charges shall be the amounts reflected in the proposed tariff sheets attached hereto in Stipulation Exhibits 7 (KU), 8 (LG&E electric), and 9 (LG&E gas).

4.4. **Curtailable Service Riders.** Concerning the Utilities' Curtailable Service Riders ("CSR"), the Parties agree that CSR customers may choose between Options A and B as follows:

(A) Option A: The Utilities' proposed CSR credits and tariff provisions as filed in these proceedings.

(B) Option B: The Utilities' existing CSR tariff provisions with the modifications below:

(i) CSR credits for both Utilities of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission).

(ii) A Utility may request physical curtailment when more than 10 of the Utilities' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Utilities are making off-system sales. However, to avoid a physical curtailment a CSR customer may buy through a requested curtailment at the Automatic Buy-Through Price. If all available units have been dispatched or are being dispatched, the Utilities may request a physical curtailment of the CSR customer without a buy-through option.

(iii) A Utility may request physical curtailment of a CSR customer no more than 20 times per calendar year totaling no more than 100 hours. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours of economic curtailments.

(iv) After receiving a physical curtailment request from the Utility where a buy-through option is available, a CSR customer will have 10 minutes to inform the Utility whether the customer elects to buy through or physically curtail. If the customer elects to physically curtail, the customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time the Utility requests curtailment to the time the customer must implement the curtailment). If a customer does not respond within 10 minutes of notice of a curtailment request from the Utility, the customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the customer.

(v) After receiving a physical curtailment request from the Utility when no buy-through option is available, a CSR customer will have 40 minutes to carry out the required physical curtailment.

(C) The Utilities will initially assign all existing CSR customers to Option B as described above. Following the initial assignment, a CSR customer may elect Option A at any time, which election will take effect beginning with the customer's first full billing cycle following the election. After a CSR makes its first election or any subsequent election, the customer must take service under the chosen option for at least 24 full billing cycles before a new election can become effective.

(D) LG&E will permit any customer interested in participating in CSR to give notice of interest by July 1, 2017; after that date, only those customers already participating in LG&E's CSR may continue their participation at their then-current levels. Customers that have given notice of interest on or before July 1, 2017, may elect to begin participating in CSR no later than January 1, 2019. LG&E's existing capacity cap will continue to apply, and all available CSR capacity will be available for participation on a first come, first served basis to those giving notice of interest by July 1, 2017.

(E) KU's CSR will be closed to new or increased participation as of July 1, 2017.

These proposed tariff changes are shown in Stipulation Exhibits 7 (KU) and 8 (LG&E electric) attached hereto.

4.5. Five-Year Limit to Gas Line Tracker Recovery for Transmission Modernization and Steel Service Line Replacement Programs. The Parties agree that LG&E will recover costs related to its proposed Transmission Modernization and Steel Service Line Replacement Programs through its Gas Line Tracker ("GLT") cost-recovery mechanism for five years ending June 30, 2022. Absent further action by the Commission concerning recovery of these programs' costs by June 30, 2022, any remaining costs for such programs will be recovered through base rates via a base-rate roll-in effective for service rendered on and after July 1, 2022. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto. This provision does not preclude LG&E from seeking Commission approval to recover other appropriate costs through the GLT mechanism.

4.6. Revisions to Proposed Substitute Gas Sales Service (Rate SGSS). The Parties agree that LG&E will revise its proposed Rate SGSS such that monthly billing demand will be based on greatest of (1) Maximum Daily Quantity ("MDQ"), (2) current month's highest daily volume of gas delivered, or (3) 70 percent of the highest daily volume of gas delivered during the previous 11 monthly billing periods. Also, LG&E will revise the provision of Rate SGSS concerning setting the MDQ such that the MDQ for any customer taking service under Rate SGSS when it first becomes effective will be 70% of the highest daily volume projected by LG&E for the customer in the forecasted test year used by LG&E in Case No. 2016-00371. For all other customers that later begin taking service under Rate SGSS, the customer and LG&E may mutually agree to establish the level of the MDQ; provided, however, that in the event that the customer and LG&E cannot agree upon the MDQ, then the level of the MDQ will be equal to 70% of the highest daily volume used by the customer during the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected; in the event that such daily gas usage is not available, then the MDQ will be equal to 70% of the customer's average daily use for the highest month's gas use in the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected. In no case will the MDQ be greater than 5,000 Mcf/day. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto.

4.7. Sports Field Lighting Pilot Tariff Provisions. The Parties agree that the Utilities will add to their electric tariffs a voluntary sports field lighting rate schedule, Pilot Rate OSL – Outdoor Sports Lighting Service, on a limited-participation pilot basis (limited to 20 pilot participants per Utility). The pilot rate uses a time-of-day rate structure. The purpose of the pilot is to determine if sports fields have sufficiently different service characteristics to support permanent sports field tariff offerings. The proposed tariff provisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.8. Agreement Not to Split Residential and General Service Electric Energy Charges in Tariffs. The Parties agree that the Utilities will not split their residential and general service electric energy charges into Infrastructure and Variable components as the Utilities had proposed in their applications in these proceedings. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.9. Agreement to File a Study Regarding 100% Base Demand Ratchets for Rate TODS. The Utilities will file in their next base-rate proceedings a study concerning the impacts of 100% base demand ratchets for Rate TODS.

4.10. Rate TODP 60-Minute Exemption from Setting Billing Demand Following Utility System Fault. For customers with their own generation, for 60 minutes immediately following a Utility-system fault, but not a Utility energy spike or a fault on a customer's system, the Utilities will not use any demand data for a Rate TODP customer to set billing demand. This 60-minute exemption from setting billing demand permits customers who have significant onsite generation (i.e., 1 MW or more) that comes offline due to a Utility-system fault to reset and bring back online their own generation before the Utilities will measure demand to be used for billing purposes. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.11. Optional Pilot Rates for Schools Subject to KRS 160.325. The Parties agree that the Utilities will add to their electric tariffs optional pilot tariff provisions for schools subject to KRS 160.325. The pilot rates will not be limited in the number of schools that may participate, but will be limited by the projected revenue impact to the Utilities. Each utility's pilot rate provisions will be available to new participants until the total projected revenue impact (reduction) for each Utility is $750,000 annually compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. KSBA will be responsible for proposing schools for participation in the pilot rates and the order in which such schools are proposed; the Utilities will calculate and provide to KSBA the projected revenue impact of each proposed school's taking service under pilot rates. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

ARTICLE V. TREATMENT OF CERTAIN SPECIFIC ISSUES

5.1. Regulatory Accounting for Over- and Under-Recovery of Regulatory Assets. The Parties agree to, and ask the Commission to approve, the Utilities' continued use of regulatory asset accounting for regulatory assets embedded in the Utilities' proposed revenue requirement except that shorter-lived regulatory assets should be credited for the amounts collected through base rates even if such amortization results in changing such a regulatory asset to a regulatory liability with any remaining balances being addressed in the Utilities' next base rate case. This would include the regulatory assets for rate case expenses, 2011 summer storm expenses, and Green River. This will help ensure the Utilities only recover actual costs incurred and do not ultimately over-recover such regulatory assets as they are amortized and recovered through base rates.

5.2. Commitment to Apply for School Energy Managers Program ("SEMP") Extension. The Utilities commit to file with the Commission an application proposing a two-year extension of SEMP (for July 1, 2018, through June 30, 2020). The total annual level of funding to be proposed is $725,000; prior to filing the application, the Utilities will consult with

KSBA to determine an appropriate allocation of the total annual funds between KU and LG&E. The Utilities commit to file the above-described application with the Commission no later than December 31, 2017.

5.3. Commitment to File Lead-Lag Study in Next Base-Rate Cases. The Utilities commit to file a lead-lag study in their next base-rate cases.

5.4. Collaborative Study Regarding Electric Bus Infrastructure and Rates. The Utilities commit to fund a study concerning economical deployment of electric bus infrastructure in the Louisville and Lexington areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses. The Utilities commit to work collaboratively with Louisville Metro, LFUCG, and any other interested Parties to these proceedings to develop the parameters for the study, including reasonable cost and timing, and to review the study's results with representatives of Louisville Metro and LFUCG. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.5. LED Lighting Collaborative. The Utilities commit to engage in good faith with Louisville Metro, LFUCG, and any other interested Parties to these proceedings in a collaborative to discuss issues related to LED lighting to determine what LED street lighting equipment and rate structures might be offered by the Utilities. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.6. Home Energy Assistance Charges. The Parties agree that KU will increase its monthly residential charge for the Home Energy Assistance ("HEA") program from the current $0.25 per month to $0.30 per month, which shall remain effective through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period. The Parties further agree that LG&E will continue its monthly residential charge (for gas and electric service) for the Home Energy Assistance ("HEA") program at $0.25 per month, which shall remain effective until the effective date of new base rates for the Utilities following their next general base-rate cases. The change to the KU HEA charge is reflected in the proposed tariff sheets attached hereto as Stipulation Exhibit 7.

5.7. Low-Income Customer Support. The Utilities commit to contribute a total of $1,450,000 of shareholder funds per year, which commitment will remain in effect through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period.

(A) The total annual shareholder contribution from KU shall be as follows: $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs.

(B) The total annual shareholder contribution from LG&E shall be as follows: $700,000 to ACM for utility assistance and $180,000 for HEA.

(C) KU agrees that up to 10% of its total contributions to CAC may be used for reasonable administrative expenses.

(D) LG&E agrees that up to 10% of its total contributions to ACM may be used for reasonable administrative expenses.

(E) None of the Utilities' shareholder contributions will be conditioned upon receiving matching funds from other sources.

(F) The Utilities commit not to seek reductions to their HEA charges that would become effective before June 30, 2021, for LG&E or KU regardless of whether the Utilities file one or more base-rate cases during that commitment period.

5.8. All Other Relief Requested by Utilities to Be Approved as Filed. The Parties agree and recommend to the Commission that, except as modified in this Stipulation and the exhibits attached hereto, the rates, terms, and conditions contained in the Utilities' filings in these Rate Proceedings, as well as the Companies' requests for CPCNs for their proposed Distribution Automation project, should be approved as filed.

ARTICLE VI. MISCELLANEOUS PROVISIONS

6.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

6.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Stipulation.

6.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on or about April 19, 2017, together with a request to the Commission for consideration and approval of this Stipulation for rates to become effective for service rendered on and after July 1, 2017.

6.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

6.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order. With regard to this provision, all of the Parties acknowledge that certain of the Parties, and in particular the Sierra Club, are entities with members who are not under a Party's control but who might purport to act for, or on behalf of, the Party. Therefore, the Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Stipulation in its entirety and without additional conditions.

6.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

6.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

6.8. The Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

6.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

6.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

6.11. The Parties hereto agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

6.12. The Parties hereto agree that neither the Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

6.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

6.14. The Parties hereto agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

6.15. The Parties hereto agree that this Stipulation may be executed in multiple counterparts.

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1: KU Depreciation Rates

Stipulation Exhibit 2: LG&E Electric Depreciation Rates

Stipulation Exhibit 3: LG&E Gas Depreciation Rates

Stipulation Exhibit 4: KU Revenue Allocation Schedule

Stipulation Exhibit 5: LG&E Electric Revenue Allocation Schedule

Stipulation Exhibit 6: LG&E Gas Revenue Allocation Schedule

Stipulation Exhibit 7: KU Tariff Sheets

Stipulation Exhibit 8: LG&E Electric Tariff Sheets

Stipulation Exhibit 9: LG&E Gas Tariff Sheets

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (KRR w/permission)
Allyson K. Sturgeon

Association of Community Ministries, Inc.

HAVE SEEN AND AGREED:

By: ______________________

Lisa Kilkelly
Eileen Ordover

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By: ______________________________

Kent Chandler
Lawrence W. Cook
Rebecca W. Goodman

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE SEEN AND AGREED:

By:______________________________
Iris G. Skidmore

United States Department of Defense and All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: Emily W. Medlyn
____

Emily W. Medlyn
G. Houston Parrish

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________
Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

Kentucky League of Cities

HAVE SEEN AND AGREED:

By:______________________

Laura Ross

The Kroger Company

HAVE SEEN AND AGREED:

By: Robert C. Moore
Robert C. Moore

Kentucky School Boards Association

HAVE SEEN AND AGREED:

By: Matthew R Malone (KRR w/ permission)

Matthew R. Malone

William H. May, III

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: *M. Todd Osterloh* ______________________

James W. Gardner
M. Todd Osterloh
David J. Barberie
Andrea C. Brown
Janet M. Graham

Subject to ratification by the Urban County Council

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By: ______________________
Michael J. O'Connell,
Jefferson County Attorney

-and-

By: ______________________
Gregory T. Dutton,
Counsel for Louisville Metro

Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By: Tom FitzGerald (KRR w/ permission)
Tom FitzGerald

Sierra Club, Alice Howell, Carl Vogel
and Amy Waters

HAVE SEEN AND AGREED:

By:______________________________
Joe F. Childers

____
Casey Roberts

____
Matthew E. Miller

JBS Swift & Co.

HAVE SEEN AND AGREED:

By:________________________________

Dennis G. Howard, II

Wal-Mart Stores East, LP and Sam's East, Inc.

HAVE SEEN AND AGREED:

By: ______________________

Barry N. Naum
Don C.A. Parker

SECOND STIPULATION AND RECOMMENDATION

This Second Stipulation and Recommendation ("Second Stipulation") is entered into this first day of May 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), and Kentucky Cable Telecommunications Association ("KCTA"). (Collectively, the Utilities, AT&T and KCTA are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"), AT&T, Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"), KCTA, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky League of Cities ("KLC"), The Kroger Company ("Kroger"), Kentucky School Boards Association ("KSBA"), Lexington-Fayette Urban County Government ("LFUCG"), Sierra Club, Alice Howell, and Carl Vogel, and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart");

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to Association of Community Ministries, Inc., AG, AT&T, United States Department of Defense and All Other Federal Executive Agencies, KCTA, KIUC, Kroger, KSBA, Louisville/Jefferson County Metro Government, Metropolitan Housing Coalition, Sierra Club and Amy Waters, JBS Swift & Co., and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of a stipulation and recommendation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, all parties to these proceedings except AT&T and KCTA reached agreement and entered into a stipulation and recommendation ("First Stipulation"), which the Utilities filed with the Commission on April 19, 2017;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Second Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 25, 2017, at the offices of the Commission, during which a number of procedural and substantive issues were discussed;

WHEREAS, it is understood by all Parties hereto that this Second Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Second Stipulation;

WHEREAS, the Parties agree that this Second Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues addressed herein, and that the First and Second Stipulations, considered together, produce a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Second Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. <u>RATE PSA MODIFICATIONS</u>

1.1. Attachment Charges for Wireline Facilities. The Parties stipulate that an annual attachment charge of $7.25 for a wireline facility is fair, just, and reasonable. The Commission previously approved this charge in the Utilities' most recent general rate case proceedings, Cases No. 2014-00371 and No. 2014-00372. The Utilities have not proposed to adjust this rate, which assumes that a wireline facility will require one foot of usable pole space. AT&T and KCTA have previously advised the Commission that they have no objections to this rate remaining in effect.

1.2. Attachment Charges for Pole-Top Wireless Facilities. The Parties stipulate that a fair, just, and reasonable rate for wireless facilities attached to the top of the Utilities' structures is $36.25 per year. They agree that for purposes of determining the annual charge, a pole-top wireless facility should be allocated five feet of usable pole space. The Utilities assert that this allocation is based upon the premise that, as the Utilities typically have electric facilities located at or near the top of their distribution poles, a pole top wireless facility, such as an antenna, requires a five foot taller pole to maintain a safe working distance of at least 48 inches between the electric facilities and the pole top antenna. Thus, the Utilities assert that the Wireless Facility owner is responsible for the top 5 feet of the pole: one foot for the antenna and four feet of clearance above the power space. Without adopting the Utilities' assertions set out in the preceding two sentences, AT&T agrees that an allocation of five feet of usable pole space is supported by evidence in the record. As the Commission has previously approved the annual rate of $7.25 for one foot of pole space, the use of five feet will produce an annual charge of $36.25.

1.3. Attachment Charges for Mid-Pole Wireless Facilities. The Parties stipulate and agree that, given the lack of information regarding the size and characteristic of wireless antennas and other devices that may be attached to an electric utility pole in the communications space, a uniform rate for such attachments cannot be easily developed and that the rate for such attachments should be developed on a case-by-case basis through special contracts until a sufficient number of such attachments have been made to the Utilities' structures to develop a tariffed rate. At the time of their next general rate applications, the Utilities will determine if they have sufficient evidence regarding mid-pole devices to determine whether a uniform rate is appropriate and, if so, revise the PSA Rate Schedule accordingly.

1.4. Terms and Conditions of Rate PSA. The Parties stipulate and agree that revisions to the originally proposed version of the PSA Rate Schedule are necessary to afford sufficient flexibility for Attachment Customers to permit them to operate effectively in the unregulated, market-based telecommunications industry. The revised PSA Rate Schedules, which are shown in Exhibits 1 and 2 to this Second Stipulation, with the proposed additions and deletions clearly marked, appropriately balance an Attachment Customer's need for flexibility with the public's interest in reliable and safe electric service. The Parties stipulate that, as revised, the terms and conditions set forth in the proposed PSA Rate Schedule are fair, just, and reasonable, will promote public safety, enhance the reliability of electric service, and ensure fair and uniform treatment of Attachment Customers as well as promote the deployment and adoption of advanced communications services.

ARTICLE II. <u>FIRST STIPULATION</u>

2.1. No objections. AT&T[4] and KCTA have reviewed the First Stipulation filed with the Commission on April 19, 2017 and have no objections to it, except to the extent the First

Stipulation's electric tariff exhibits contained PSA Rate Schedules inconsistent with this Second Stipulation and its exhibits, in which case the latter should control.

2.2. AMS Collaborative. The Parties agree that the Utilities shall notify AT&T and KCTA if and when it engages in any AMS Collaborative pursuant to the First Stipulation § 1.2 and that AT&T and KCTA may, at their option, participate in any or all phases of the AMS Collaborative.

ARTICLE III. MISCELLANEOUS PROVISIONS

3.1. Except as specifically stated otherwise in this Second Stipulation, entering into this Second Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

3.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Second Stipulation.

3.3. Following the execution of this Second Stipulation, the Parties shall cause it to be filed with the Commission on or about May 1, 2017, together with a request to the Commission for consideration and approval of this Second Stipulation for rates to become effective for service rendered on and after July 1, 2017.

3.4. This Second Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Second Stipulation and the First Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the First and Second Stipulations, taken together, produce a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the First and Second Stipulations as such.

3.5. If the Commission issues an order adopting this Second Stipulation in its entirety and without additional conditions, irrespective of whether the Commission approves the terms of the First Stipulation, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to the portions of such order that concern this Second Stipulation. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Second Stipulation in its entirety and without additional conditions.

3.6. If the Commission does not accept and approve this Second Stipulation in its entirety and without additional conditions, then any adversely affected Party may withdraw from the Second Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all

Parties that have not withdrawn will continue to be bound by the terms of the Second Stipulation as modified by the Commission's order.

3.7. If the Second Stipulation is voided or vacated for any reason after the Commission has approved the Second Stipulation, none of the Parties will be bound by the Second Stipulation.

3.8. The Second Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

3.9. The Second Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

3.10. The Second Stipulation, including its Exhibits, constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Second Stipulation.

3.11. The Parties hereto agree that, for the purpose of the Second Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

3.12. The Parties hereto agree that neither the Second Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Second Stipulation. This Second Stipulation shall not have any precedential value in this or any other jurisdiction.

3.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Second

Stipulation and based upon the foregoing are authorized to execute this Second Stipulation on behalf of their respective Parties.

3.14. The Parties hereto agree that this Second Stipulation is a product of negotiation among all Parties hereto, and no provision of this Second Stipulation shall be strictly construed in favor of or against any party.

3.15. The Parties hereto agree that this Second Stipulation may be executed in multiple counterparts.

(This space intentionally left blank.)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (with permission KRR)
Allyson K. Sturgeon

BellSouth Telecommunications, LLC d/b/a AT&T Kentucky

HAVE SEEN AND AGREED:

By: Cheryl R Winn

Cheryl R. Winn

Kentucky Cable Telecommunications Association

HAVE SEEN AND AGREED:

By:____________________________
Gardner F. Gillespie
Paul Werner
Megan Grant

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00370 DATED JUN 22 2017

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09070

SCHEDULE RTOD-ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	
Off Peak Hours	$ .05916
On Peak Hours	$ .27646

SCHEDULE RTOD-DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Month	$12.25
Energy charge per kWh	$ 0.04504
Demand Charge per kW	
Off Peak Hours	$ 3.44
On Peak Hours	$ 7.87

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09070

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Month – Single Phase	$31.50
Basic Service Charge per Month – Three Phase	$50.40
Energy Charge per kWh	$ .10428

SCHEDULE AES
ALL ELECTRIC SCHOOL

Basic Service Charge per Month – Single Phase	$ 85.00
Basic Service Charge per Month – Three Phase	$140.00
Energy Charge per kWh	$ .08306

SCHEDULE PS
POWER SERVICE

Secondary Service:	
Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$ 20.17
Winter Rate	$ 17.95
Energy Charge per kWh	$ .03547
Primary Service:	
Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Summer Rate	$ 20.35
Winter Rate	$ 18.16
Energy Charge per kWh	$ .03448

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 2.73
Intermediate Demand Period	$ 6.11
Peak Demand Period	$ 7.79
Energy Charge per kWh	$ .03508

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.75
Intermediate Demand Period	$ 5.03
Peak Demand Period	$ 6.43
Energy Charge per kWh	$ .03415

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.99
Intermediate Demand Period	$ 4.94
Peak Demand Period	$ 6.31
Energy Charge per kWh	$ .03338

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:

Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.45
Intermediate Demand Period	$ 4.48
Peak Demand Period	$ 5.91
Energy Charge per kWh	$ .03415

Transmission:

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.53
Intermediate Demand Period	$ 2.29
Peak Demand Period	$ 3.25
Energy Charge per kWh	$ .03315

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only	Ornamental
High Pressure Sodium:		
5,800 Lumens - Cobra Head	$ 9.86	$ 13.52
9,500 Lumens - Cobra Head	$ 10.34	$ 14.21
22,000 Lumens - Cobra Head	$ 16.08	$ 20.22
50,000 Lumens - Cobra Head	$ 25.61	$ 28.37
9,500 Lumens - Directional	$ 10.19	
22,000 Lumens - Directional	$ 15.42	
50,000 Lumens - Directional	$ 21.95	
9,500 Lumens - Open Bottom	$ 8.87	
Metal Halide		
32,000 Lumens - Directional	$ 22.80	
Light Emitting Diode (LED)		
8,179 Lumens - Cobra Head	$ 14.92	
14,166 Lumens - Cobra Head	$ 18.09	
23,214 Lumens - Cobra Head	$ 27.63	
5,007 Lumens - Open Bottom	$ 9.94	

Underground:

	Fixture Only	Decorative Smooth	Historic Fluted
High Pressure Sodium:			
5,800 Lumens - Colonial		$ 12.59	
9,500 Lumens - Colonial		$ 12.92	
5,800 Lumens - Acorn		$ 17.18	$ 24.50
9,500 Lumens - Acorn		$ 17.63	$ 25.09
5,800 Lumens - Victorian			$ 34.07
9,500 Lumens - Victorian			$ 34.39
5,800 Lumens - Contemporary	$ 17.12	$ 19.35	
9,500 Lumens - Contemporary	$ 17.00	$ 23.94	

22,000 Lumens - Contemporary	$ 19.84	$ 30.82
50,000 Lumens - Contemporary	$ 24.15	$ 38.09
4,000 Lumens - Dark Sky Lantern		$ 24.87
9,500 Lumens - Dark Sky Lantern		$ 25.99

Metal Halide

32,000 Lumens - Contemporary	$ 24.68	$ 38.87

Light Emitting Diode (LED)

8,179 Lumens - Cobra Head		$ 35.44
14,166 Lumens - Cobra Head		$ 38.61
23,214 Lumens - Cobra Head		$ 48.14
5,665 Lumens - Open Bottom		$ 37.51

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture and Pole
High Pressure Sodium:		
4,000 Lumens - Cobra Head	$ 8.84	$ 12.16
50,000 Lumens - Cobra Head	$ 14.06	
5,800 Lumens - Open Bottom	$ 8.54	
Metal Halide		
12,000 Lumens - Directional	$ 16.13	$ 20.89
32,000 Lumens - Directional		$ 27.56
107,800 Lumens - Directional	$ 47.70	$ 52.45
Mercury Vapor:		
7,000 Lumens - Cobra Head	$ 10.83	$ 13.34
10,000 Lumens - Cobra Head	$ 12.84	$ 15.07
20,000 Lumens - Cobra Head	$ 14.53	$ 17.01
7,000 Lumens - Open Bottom	$ 11.87	
Incandescent:		
1,000 Lumens - Tear Drop	$ 3.81	
2,500 Lumens - Tear Drop	$ 5.11	
4,000 Lumens - Tear Drop	$ 7.63	
6,000 Lumens - Tear Drop	$ 10.19	

Underground:

		Decorative Smooth	Historic Fluted
Metal Halide			
12,000 Lumens - Directional		$ 31.20	
32,000 Lumens - Directional		$ 36.99	
107,800 Lumens - Directional		$ 61.66	
12,000 Lumens - Contemporary	$ 17.45	$ 31.42	
107,800 Lumens - Contemporary	$ 51.32	$ 65.28	
High Pressure Sodium:			
4,000 Lumens - Acorn		$ 15.69	$ 23.13
4,000 Lumens - Colonial		$ 11.18	
5,800 Lumens - Coach		$ 34.07	
9,500 Lumens - Coach		$ 34.39	
16,000 Lumens - Granville		$ 62.30	

SCHEDULE TE
TRAFFIC ENERGY SERVICE

Basic Service Charge per Month	$ 4.00
Energy Charge per kWh	$ .09013

SCHEDULE PSA
POLE AND STRUCTURE ATTACHMENT CHARGES

Per Year for Each Attachment to Pole	$ 7.25
Per Year for Each Linear Foot of Duct	$ .81
Per Year for Each Wireless Facility	$36.25

RATE CSR-1
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 3.20	$ 3.31
Non-compliance Charge Per kVA	$16.00	$16.00

RATE CSR-2
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 5.90	$ 6.00
Non-compliance Charge		
Per kVA	$ 16.00	$ 16.00

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	$ 1.04
Primary Distribution	$ .86

EVSE
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	$182.27
Dual Charger	$306.01

EVC
ELECTRIC VEHICLE CHARGING SERVICE

Fee per Hour	$ 2.84

EVSE-R
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	$131.41
Dual Charger	$204.31

SSP
SOLAR SHARE PROGRAM RIDER

Monthly Charge:	
Solar Capacity Charge	$ 6.24
Solar Energy Credit per kWh of Pro Rata Energy Produced:	
RS	$ .03520
RTOD-Energy	$ .03520
RTOD-Demand	$ .03520
VFD	$ .03520

GS	$ .03524
AES	$ .03526
PS Secondary	$ .03547
PS Primary	$ .03448
TODS	$ .03508
TODP	$ .03415

SPS
SCHOOL POWER SERVICE

Secondary Service:	
Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$ 17.89
Winter Rate	$ 15.92
Energy Charge per kWh	$ .03572

STOD
SCHOOL TIME-OF-DAY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 4.83
Intermediate Demand Period	$ 4.25
Peak Demand Period	$ 5.76
Energy Charge per kWh	$ .03527

OSL
OUTDOOR SPORTS LIGHTING SERVICE

Secondary Service:	
Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Peak Demand Period	$ 16.15
Base Demand Period	$ 2.73
Energy Charge per kWh	$ .03571
Primary Service:	
Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Peak Demand Period	$ 16.32
Base Demand Period	$ 2.75
Energy Charge per kWh	$ .03472

UNAUTHORIZED RECONNECT CHARGE

Tampering or Unauthorized Connection or Reconnection Fee:		
Meter Replacement Not Required	$	70.00
Single Phase Standard Meter Replacement Required	$	90.00
Single Phase AMR Meter Replacement Required	$	110.00
Single Phase AMS Meter Replacement Required	$	174.00
Three Phase Meter Replacement Required	$	177.00

HEA
HOME ENERGY ASSISTANCE PROGRAM

Per Month	$	.30

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AG Exhibit 6

OAG EXHIBIT 6

RATE SP

SEASONAL SPORTS SERVICE

APPLICABILITY

Applicable to electric service required for sports installations, such as football and baseball fields, swimming pools, tennis courts, and recreational areas, promoted, operated and maintained by non-profit organizations, such as schools, churches, civic clubs, service clubs, community groups, and municipalities, where such service is separately metered and supplied at one point of delivery, except, not applicable to private sports installations which are not open to the general public. This rate is available only to customers to whom service was supplied in accordance with its terms on June 25, 1981.

TYPE OF SERVICE

Alternating current 60 Hz, single or three phase at the Company's standard secondary voltage.

NET MONTHLY BILL

Computed in accordance with the following charges (kilowatt hours are abbreviated as kWh):

1. Base Rate
   (a) Customer Charge $7.50 per month

   (b) Energy Charge $0.100598 per kWh (R)

2. Applicable Riders
   The following riders are applicable pursuant to the specific terms contained within each rider:
   Sheet No. 78, Rider DSMR, Demand Side Management Rider
   Sheet No. 80, Rider FAC, Fuel Adjustment Clause
   Sheet No. 81, Rider MSR-E, Merger Savings Credit Rider – Electric
   Sheet No. 82, Rider PSM, Profit Sharing Mechanism

The minimum charge shall be a sum equal to 1.5% of the Company's installed cost of transformers and metering equipment required to supply and measure service, but not less than the customer charge whether service is on or disconnected.

RECONNECTION CHARGE

A charge of $25.00 is applicable to each season to cover in part the cost of reconnection of service.

LATE PAYMENT CHARGE

Payment of the Net Monthly Bill must be received in the Company's office within twenty-one (21) days from the date the bill is mailed by the Company. When not so paid, the Gross Monthly Bill, which is the Net Monthly Bill plus 5%, is due and payable.

Issued by authority of an Order of the Kentucky Public Service Commission dated July 31, 2017 in Case No. 2017-00005.

Issued: August 18, 2017
Effective: August 30, 2017
Issued by James P. Henning, President

KENTUCKY
PUBLIC SERVICE COMMISSION
John Lyons
ACTING EXECUTIVE DIRECTOR
(T) John S. Lyons
EFFECTIVE
(T)
(T) 8/30/2017
(T) PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TERMS AND CONDITIONS

The term of contract shall be for a minimum period of one (1) year terminable thereafter on thirty (30) days written notice by either the customer or the Company.

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission, as provided by law.

Issued by authority of an Order of the Kentucky Public Service Commission dated July 31, 2017 in Case No. 2017-00005.

Issued: August 18, 2017
Effective: August 30, 2017
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(T) **8/30/2017**
(T) PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

AG Exhibit 7

OAG EXHIBIT 7

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))	CASE NO. 2017-00321

ORDER

Duke Energy Kentucky, Inc. ("Duke Kentucky") is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to approximately 140,600 consumers in Boone, Campbell, Grant, Kenton, and Pendleton counties.[1] Duke Kentucky also is a utility engaged in purchasing, selling, storing, and transporting natural gas to approximately 98,200 customers in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton counties.[2] Its most recent general rate increase for its electric operations was granted in Case No. 2006-00172.[3]

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[1] Application at 2. *See also*, Direct Testimony of James P. Henning ("Henning Testimony") at 4.

[2] *Id.*

[3] Application at 4. Case No. 2006-00172, *Application of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky for an Adjustment of Electric Rates* (Ky. PSC Dec. 21, 2006).

BACKGROUND

On September 1, 2017, Duke Kentucky filed an application requesting authorization to increase its electric base rate revenue to a new total of $357.5 million, which reflects an increase from its current rates of approximately $48.6 million.[4] The monthly residential electric bill increase due to the proposed electric base rates would be 17.1 percent, or approximately $15.17, for a typical residential customer using 1,000 kWh of electricity.[5] Duke Kentucky subsequently revised its proposed revenue increase to $30.12 million.[6] The revised revenue requirement would amount to an 11 percent increase, or approximately $9.73, for a typical residential customer using 1,000 kWh of electricity each month.[7] Duke Kentucky states that the primary reason for the requested increase is that Duke Kentucky's earned rate of return on capitalization obtained from its current electric operations is 2.850 percent, which is inadequate to enable Duke Kentucky to continue providing safe, reasonable, and reliable service to its customers, and is insufficient to afford Duke Kentucky a reasonable opportunity to earn a fair return on its investment property that is used to provide such service while attracting necessary capital at reasonable rates.[8] In addition to the base rate increase, Duke Kentucky also is requesting authority to recover certain regulatory assets, including storm restoration expenses resulting from Hurricane Ike in 2008; research and development investments;

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[4] Application at 5.

[5] *Id.*

[6] Amended Rebuttal Testimony of Sarah E. Lawler at 1.

[7] Duke Kentucky's response to Commission Staff's Post-Hearing Data Request ("Staff's PH-DR"), Item 9.

[8] Application at 6.

incremental operations and maintenance ("O&M") related to the acquisition of the entirety of the East Bend Generating Station ("East Bend"); and O&M expenses related to the creation of a residential Advanced Metering Infrastructure ("AMI") opt-out tariff.[9]

Duke Kentucky also is proposing to implement a distribution reliability and integrity improvement plan that will be comprised of specific new and Commission-approved measures to enhance the safety and reliability of Duke Kentucky's distribution system.[10] Duke Kentucky requests to recover the costs of this plan through a surcharge mechanism called Rider Distribution Capital Investment ("Rider DCI").[11] Duke Kentucky proposes, as part of this application, a Targeted Underground program to improve distribution reliability by relocating at-risk overhead circuits to underground service.[12] Rider DCI would include incremental capital investment, depreciation, taxes, and a reasonable return that is incremental to base rates.[13] Rider DCI would be adjusted and subject to annual true-up following Commission review and approval; the annual application also would include any new reliability or integrity programs for Commission consideration and approval for implementation as part of Duke Kentucky's distribution integrity and reliability plan.[14]

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[9] *Id.*

[10] *Id.* at 13–14.

[11] *Id.*

[12] Application at 14.

[13] *Id.*

[14] *Id.*

Also as part of the instant application, Duke Kentucky is requesting approval of an environmental compliance plan and the establishment of an environmental surcharge mechanism, both pursuant to KRS 278.183.[15]

Duke Kentucky is seeking approval of a new reconciliation mechanism to recover FERC-jurisdictional transmission expenses that Duke Kentucky incurs, incremental (above and below) to what is reflected in base rates ("Rider FTR").[16] According to Duke Kentucky, Rider FTR will operate much like its fuel adjustment clause ("FAC") and Accelerated Service Replacement Program in that such transmission costs will be filed regularly and subject to periodic review by the Commission.[17]

Lastly, Duke Kentucky also is proposing to modify the following existing policies and tariffs and implement the following new programs and measures: a voluntary Enhanced Customer Solutions, including optional billing alternatives and notifications; a revised FAC; a revised Profit Sharing Mechanism Rider ("Rider PSM"); a new LED street lighting tariff; and revisions to its cogeneration tariff.[18] Duke Kentucky submitted a depreciation study in support of its application, and requests that its proposed depreciation rates be approved.

By letter dated September 7, 2017, the Commission notified Duke Kentucky that its application was rejected because it contained filing deficiencies and that the application would not be deemed filed until the deficiencies were cured. Duke Kentucky submitted information on September 15, 2017, addressing the deficiencies. By Order

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[15] Application at 15.

[16] Application at 18–19.

[17] Application at 19.

[18] Application at 20.

dated September 27, 2017, the Commission determined that Duke Kentucky had cured all of the filing deficiencies and that Duke Kentucky's application was deemed filed as of September 15, 2017. The September 27, 2017 Order also found that the earliest date that Duke Kentucky's proposed rates could be effective was October 15, 2017. Pursuant to the September 27, 2017 Order, the Commission suspended Duke Kentucky's proposed rates for six months, up to and including April 14, 2018. Further, the September 27, 2017 Order established a procedural schedule for the processing of this matter, which provided for a deadline for filing intervention requests; two rounds of discovery upon Duke Kentucky's application; a deadline for the filing of intervenor testimony; one round of discovery upon any intervenor testimony; and an opportunity for Duke Kentucky to file rebuttal testimony.

The following parties were granted intervention in this proceeding: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Board Association ("KSBA"); Kroger Company ("Kroger"); and Northern Kentucky University ("NKU").

The Commission held an information session and public meeting for the purpose of taking public comments on February 8, 2018, at Boone County High School in Florence, Kentucky. A formal hearing was held at the Commission's offices on March 6–8, 2018. Duke Kentucky provided responses to post-hearing data requests on March 23, 2018, and April 10, 2018. All of the parties filed simultaneous post-hearing briefs on April 2, 2018. The matter now stands submitted for a decision.

REVENUE AND EXPENSES

Contested Revenue Requirement Issues

Duke Kentucky originally proposed an annual increase in its electric revenues of $48,646,213.[19] Duke Kentucky subsequently revised its requested revenue requirement increase to $30,119,059.[20] The Attorney General is the only intervenor who presented evidence addressing Duke Kentucky's proposed revenue increase, arguing that Duke Kentucky should be required to decrease its electric revenues by $11,901,000.[21] The Commission must consider the evidentiary record on these issues as presented by Duke Kentucky and the Attorney General and render a decision based on a determination of Duke Kentucky's capital, rate base, operating revenues, operating expenses, and revenue allocation.

Test Period

Duke Kentucky proposes the 12-month period ending March 31, 2019, as the forecasted test period for determining the reasonableness of its proposed rates. None of the intervenors contested the use of this period as the test period. The Commission finds it is reasonable to use the 12-month period ending March 31, 2019, as the test period in this case. That 12-month period is the most feasible period to use for setting rates based on the timing of Duke Kentucky's filing and, except for the adjustments approved herein, the revenues and expenses incurred during that period are neither unusual nor

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[19] Application, Schedule C-1.

[20] Amended Rebuttal Testimonies of William Don Wathen, Jr. and Sarah E. Lawler ("Amended Rebuttal Testimonies of Wathen and Lawler") at page 3.

[21] Testimony Errata for Lane Kollen at page 4. In his Post-Hearing Brief, the Attorney General revised his recommended decrease to $14.839 million.

extraordinary. In using this forecasted test period, the Commission has given full consideration to appropriate known and measurable changes.

Jurisdictional Rate Base Ratio

Duke Kentucky proposed a test-year-end Kentucky jurisdictional rate base of $700,204,561.[22] The Kentucky jurisdictional electric rate base is divided by Duke Kentucky's test-year-end total company electric rate base to derive the Kentucky jurisdictional electric rate base ratio ("Jurisdictional Ratio") for Duke Kentucky. This Jurisdictional Ratio is then applied to Duke Kentucky's total company electric capitalization to derive its Kentucky jurisdictional electric capitalization. The Jurisdictional Ratio uses the test-year-end rate base before any ratemaking adjustments applicable to either Kentucky jurisdictional operations or other jurisdictional operations. Duke Kentucky used a Jurisdictional Ratio of 100 percent.[23] The Commission has reviewed and agrees with the calculation of Duke Kentucky's test-year electric rate base for purposes of establishing the Jurisdictional Ratio.

Pro Forma Jurisdictional Rate Base

Duke Kentucky calculated a pro forma jurisdictional rate base of $700,204,561,[24] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base. The Attorney General provided testimony and several adjustments to Duke Kentucky's proposed rate base as discussed below. The Commission finds seven adjustments are warranted to Duke Kentucky's rate base. The

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[22] Application, Schedule B-1.

[23] *Id.*, Schedule B-7.

[24] *Id.*, Schedule B.1. Duke Kentucky is not requesting to include recovery of Construction Work in Progress in base rates.

Commission finds that the excess amortization of the Carbon Management Research Group regulatory asset in the test year and the amortization of excess accumulated deferred income tax ("ADIT") should be added to the rate base. The Commission also finds that the East Bend Operations and Maintenance Expense ("East Bend O&M") regulatory asset, the East Bend Ash Pond Asset Retirement Obligation ("East Bend Ash Pond ARO") regulatory asset, the reduction in cash working capital ("CWC"), and the reduction in depreciation expense as discussed herein due to the Commission's decision to deny use of the Equal Life Group ("ELG") procedure and require use of the Average Life Group ("ALG") procedure for computing depreciation rates, net of the related ADIT as found reasonable herein, should be removed from rate base.

The Commission accepts Duke Kentucky's proposed amortization of the protected excess ADIT. The amortization for the protected excess ADIT is based upon the Average Rate Assumption Method ("ARAM"). For the unprotected excess ADIT, the Attorney General initially proposed a 20-year amortization period.[25] Subsequently, the Attorney General proposed a five-year amortization period for the unprotected excess ADIT but did not amend his testimony to reflect the change in the amortization period.[26] The Commission finds that a reasonable amortization period for the excess ADIT for Duke Kentucky's unprotected assets should be 10 years. A 10-year amortization period for the unprotected excess ADIT will balance the impact to Duke Kentucky's cash flow and provide ratepayers the full benefit of the reduction in the federal corporate income tax in a timely manner. As a result of the foregoing adjustments, the Commission finds the total

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[25] *Id.*

[26] March 8, 2018, Video Transcript of Evidence at 3:35:00.

test-year amortization for the total excess ADIT to be $4,471,984, which is an increase of $1,651,639 over the amount proposed by Duke Kentucky. The Commission finds that the amortization of the excess ADIT related to protected and unprotected excess ADIT found reasonable herein should be removed from Duke Kentucky's ADIT, which increases its rate base. Therefore, Duke Kentucky's rate base should be increased by $4,471,984 for this adjustment.

Duke Kentucky deferred $2 million it incurred to fund carbon management research by the Carbon Management Research Group ("CMRG"). In Case No. 2008-00308, Duke Kentucky sought and obtained authorization from the Commission to defer these costs for accounting purposes.[27] The regulatory asset, net of ADIT, is included in the capitalization in this proceeding. In the instant matter, Duke Kentucky sought to recover the amortization of the deferred asset over a five-year period at $400,000 per year. In the Commission's Order in Case No. 2008-00308, it stated that the CMRG regulatory asset will be amortized over a 10-year period or $200,000 per year. Therefore, the Commission finds that the Duke Kentucky's capitalization should be increased by $200,000 to reflect the proper amount of the regulatory asset in the rate base.

The Commission finds that the ADIT arising from its requirement to change Duke Kentucky's procedure for computing depreciation rates from the ELG to the ALG procedure should reduce Duke Kentucky's rate base. As discussed in the testimony of the Attorney General, the ELG procedure front-loads depreciation expense in earlier

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[27] Case No. 2008-00308, *Joint Application of Duke Energy Kentucky, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets* (Ky. PSC Oct. 30, 2008).

years and decreases it in the later years of an asset's depreciable life, creating a mismatch of revenues and expenses.[28] The Attorney General states that the ALG procedure is the dominant procedure for other electric utilities, including all other electric utilities in Kentucky.[29] Therefore, the Commission finds that the Attorney General's position on this issue is reasonable and that Duke Kentucky should use the ALG procedure for computing depreciation rates, and that its rate base should be reduced by $2,733,299 to reflect the increase in ADIT.

The East Bend O&M regulatory asset was approved by the Commission in Case No. 2014-00201.[30] In addition, in that proceeding, the Commission authorized Duke Kentucky to defer carrying charges on the O&M expense at its cost of debt. The Attorney General disputed the amount of the regulatory asset and made a recommendation of the amount of amortization assuming that the regulatory asset was included in rate base.[31]

The Commission finds that the East Bend O&M regulatory asset should be removed from rate base and Duke Kentucky's request to amortize the East Bend O&M regulatory asset over a 10-year period is reasonable and should be approved. The Commission also finds that carrying charges should be based on the cost of debt approved herein. This adjustment reduces Duke Kentucky's rate base by $36,540,123.

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[28] Direct Testimony of Lane Kollen ("Kollen Testimony") beginning at 31.

[29] *Id.* at 32

[30] Case No. 2014-00201, *Application of Duke Energy Kentucky, Inc. for (1) a Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs Incurred as part of the Acquisition; and (4) All Other Necessary Waivers, Approvals and Relief* (Ky. PSC Dec. 4, 2014).

[31] Kollen Testimony at 31.

The East Bend Ash Pond ARO was approved by the Commission in Case No. 2015-00187.[32] Duke Kentucky proposed that the East Bend Ash Pond ARO amortization be recovered through the Environmental Surcharge Mechanism ("ESM") in its application. In addition, Duke Kentucky requested a 10-year amortization period. The Attorney General proposed that the East Bend Ash Pond ARO be removed from capitalization, as it was erroneous for Duke Kentucky to include it in both its ESM rider rate base and in base rates. The Commission finds the East Bend Ash Pond ARO should not be included in base rates because that amount is proposed to be recovered through Duke Kentucky's ESM. The Commission also finds that a 10-year amortization period is reasonable and should be approved. The parties have agreed upon this issue. This adjustment reduces Duke Kentucky's rate base by $18,509,346.

The CWC allowance included in rate base shown below is based on the adjusted operation and maintenance expenses discussed in this Order, as approved by the Commission. This adjustment reduces Duke Kentucky's rate base by $2,008,320.

Based on the Commission's finding herein where it denied Duke Kentucky's proposal to use ELG procedure rather than the ALG procedure for computing depreciation rates, the Commission finds that Duke Kentucky's accumulated depreciation in its rate base should be increased by $6,919,475.

We have determined Duke Kentucky's pro forma jurisdictional rate base for rate-making purposes for the test year to be as follows:

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[32] Case No. 2015-00187, *Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations* (Ky. PSC Dec. 15, 2015).

Total Utility Plant in Service	$1,675,994,650
Add:	
Cash Working Capital Allowance	12,207,087
Other Working Capital Allowances	40,420,974
Subtotal	$52,628,061
Deduct:	
Accumulated Depreciation	839,228,648
Accumulated Deferred Income Taxes	237,388,861
Subtotal	$1,076,617,509
Pro Forma Rate Base	$652,005,202

Reproduction Cost Rate Base

KRS 278.290 (1) states, in relevant part, that:

> the commission shall give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for rate-making purposes.

Neither Duke Kentucky nor the Attorney General provided information relative to Duke Kentucky's proposed Kentucky jurisdictional reproduction cost rate base. Therefore, the Commission finds that using Duke Kentucky's historic costs for deriving its rate base is appropriate and consistent with Commission precedents involving Duke Kentucky as well as other Kentucky jurisdictional utilities.

Revenue and Expenses

For the test year, Duke Kentucky reported actual net operating income from its electric operations of $19,212,679.[33] Duke Kentucky proposed 33 adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income of $20,091,071.[34] Through discovery, this amount was adjusted to $38,533,427. With this level of net operating income, Duke Kentucky reported an adjusted test-year revenue deficiency of $30,119,059.[35]

The Attorney General accepted 28 of Duke Kentucky's proposed adjustments to its test-year revenues and expenses; adjustments that are also acceptable to the Commission.[36] A list of the accepted adjustments is contained in the attached Appendix A.

The Attorney General proposed 17 adjustments to Duke Kentucky's operating income. Through discovery, the Attorney General and Duke Kentucky agreed on four of the operating income issues. The four items agreed upon are the inclusion of PJM make-whole and other revenues not included in Duke Kentucky's revenue forecast, the reduction in RTEP charges, the CMRG regulatory amortization expense, and the reduction in income tax expense for the research tax credits. The remaining operating income issues relate to: 1) including off-system sales ("OSS") margins to reset Rider PSM to zero; 2) reduce replacement power expense; 3) reduce vegetation management

[33] Application, Schedule C-2.

[34] *Id.*

[35] Amended Rebuttal Testimonies of Wathen and Lawler at 3.

[36] Appendix A shows the 33 adjustments to revenues and expenses accepted by the Attorney General.

expense to historic levels; 4) reduce planned outage O&M normalization; 5) reduce incentive compensation expense tied to financial performance; 6) reduce retirement plan expense; 7) increase AMI benefit levelization adjustment; 8) reduce amortization of East Bend regulatory asset to reflect lower O&M expense prior to test year; 9) reduce depreciation expense by using the ALG procedure; 10) reduce depreciation expense by removing terminal net salvage for generating units; 11) reduce remaining net salvage value included in depreciation expense; 12) reduce income tax expense to reflect reduction in federal rate; and, 13) reduce income tax expense to reflect amortization of excess ADIT, which the Commission makes the following conclusions listed below. In addition, the Commission has a discussion on the impacts of the Tax Cuts and Jobs Act ("TCJA") which was enacted on December 23, 2017.

These adjustments, and the discussion and findings thereon pertain solely to Duke Kentucky's base-rate revenue requirements. In addition to base rates, Duke Kentucky's application includes a number of proposed riders or surcharges. On the various base-rate adjustments, the Commission makes the following findings:

Rider PSM Margins

Duke Kentucky proposes to continue to include all OSS margins in the Rider PSM and that the margins be shared between customers and shareholders. Currently, ratepayers receive the benefit of the first $1 million and any margins above $1 million are shared 75 percent to ratepayers and 25 percent to shareholders. Duke Kentucky proposes to have all margins shared 90 percent to ratepayers and 10 percent to shareholders. In response to Staff's Post-Hearing Data Request, Item 11, regarding a comparison of the level of sharing under the current methodology and under the proposed change for the last three years, if Duke Kentucky's proposed split had been in effect for the years 2015, 2016, and 2017, customers would have benefited by an additional $2.1 million in 2015, $0.8 million in 2016, and $1.6 million in 2017.

The Attorney General recommends the forecasted OSS margins be removed from Rider PSM and be included as a reduction to base rates. The Attorney General states that the Commission has historically included OSS margins in the base revenue requirement and contemporaneously reset the relevant sharing mechanism to $0. The impact of this adjustment would be to reduce Duke Kentucky's proposed revenue requirement by $3.826 million.

The Commission finds that Duke Kentucky's proposal to not include PSM margins in base rates is reasonable and should be approved because the proposal would provide savings to its customers. The other Duke Kentucky proposals related to Rider PSM are discussed in the Proposed Tariff Changes section of this Order.

Replacement Power Expense

Duke Kentucky proposes to include $5.668 million that cannot be recovered through the FAC as replacement power expense for the incremental fuel and other expenses due to unplanned outages at the East Bend Station.[37] Duke Kentucky also requests authority to defer replacement power expense greater than or less than the expense included in the base rate requirement, subject to future review for ratemaking recovery.

[37] Duke Kentucky's response to the Attorney General's First Set of Data Requests ("AG's First Request"), Item 11.

The Attorney General argues that Duke Kentucky's forecasted replacement power expense is excessive compared to the actual replacement power expense of the East Bend Station for the last three years.[38] Based on the average actual replacement power expense of $1.610 million for the years 2015–2017, the Attorney General recommends Duke Kentucky's purchased power expense be reduced by $4.058 million. The Attorney General, however, agrees that Duke Kentucky should be authorized to establish a deferral mechanism for those incremental amounts greater than or less than what is in base rates for replacement power expense.[39]

The Commission agrees with the Attorney General's recommendation to reduce replacement power expense by $4.058 million, as Duke Kentucky's proposed adjustment is significantly greater than its actual costs for the prior three years (2015-2017). The changes in Duke Kentucky's generation mix, the abnormal purchased power costs in 2014 due to the polar vortex, and the use of future years in the computation of the replacement power expense make Duke Kentucky's proposed adjustment unreasonable relative to historical normalized costs. The Commission also finds that Duke Kentucky's proposed deferral mechanism is reasonable and should be approved.

Vegetation Management Expense

Duke Kentucky proposed a vegetation management expense of $4.480 million in its application.[40] This number is based in part upon Duke Energy Business Services' ("DEBS") experience in the Midwest market in its three jurisdictions (Kentucky, Indiana,

[38] Kollen Testimony at 11.

[39] *Id.* at 12.

[40] Duke Kentucky's response to Commission Staff's Second Request for Information ("Staff's Second Request"), Item 18.

and Ohio) for the period that extends into the first quarter of 2019. The proposed amount for the vegetation management expense represents an increase of $2.879 million over the base period amount.

Duke Kentucky states that its vegetation management service is almost exclusively performed by outside contractors.[41] It maintains that the large increase was primarily due to market forces as resources eligible to properly engage in vegetation management activities have become constrictive and extremely competitive for limited qualified resources.[42] Duke Energy Corporation contracts for vegetation management services throughout its service territory.[43] Its sourcing specialists engage in a Request for Proposal ("RFP") process to seek out companies that can provide the best service at the least cost throughout its entire service territory.[44] Duke Energy Corporation issued a RFP for vegetation management services for calendar years 2018 through 2020. Duke Kentucky chose a contractor who could perform the required service, but it resulted in a substantially higher cost than it had historically incurred.

Duke Kentucky maintains that it is not cost-effective for a supplier to split up vegetation management services by a smaller geographic area in its service territory.[45] Duke Kentucky further states that the means to gain the most effective contract pricing is to have sufficient work to keep a contractor's resources working all year, and that

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[41] April N. Edwards Rebuttal Testimony at 5.

[42] *Id.* at 6.

[43] *Id.*

[44] *Id.*

[45] Duke Kentucky's response to Staff's Post-Hearing Data Request, Item 2.b.

subdividing its zone into smaller segments would not provide enough work to allow that to take place.[46]

The Attorney General argued that Duke Kentucky's proposed vegetation management expense is excessive compared to the company's actual expense in the years 2012 through 2016, which ranged from a low of $1.774 million to a high of $2.309 million, with an average of $2.080 million.[47] The Attorney General recommended the Commission use a more realistic forecast based on the actual average expense mentioned above, which results in a reduction in vegetation management expense of $2.400 million.

The Commission has reviewed the confidential cost-benefit study[48] and other information related to vegetation management expense in the record of this case. We understand the market forces that have influenced this area of expense. However, we are concerned about the large increase and will require Duke Kentucky to study this issue further in order to find ways of making its vegetation management more cost-effective.

The Commission finds Duke Kentucky's proposed vegetation management expense should be reduced by $0.444 million, based on deducting the four-year average for fiscal years ending March 31, 2019, through March 31, 2022, of $4,035,571 from Duke Kentucky's proposed test year amount of vegetation management expense of $4,479,887.[49] Further, the Commission finds that, in conjunction with its next Master

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[46] *Id.*

[47] Kollen Testimony at 15.

[48] Duke Kentucky's response to the Attorney General's Post-Hearing Data Request, Item 4.

[49] Duke Kentucky response to Commission Staff's Third Request for Information ("Staff's Third Request"), Item 14.

Agreement for Vegetation Management Service ("MAVMS") contract, DEBS, in conjunction with Duke Kentucky, should bid the next MAVMS contract for the Midwest market that includes Kentucky, Indiana, and Ohio, and for a smaller geographic area limited to Duke Kentucky's service territory. The smaller geographic area should include Duke Kentucky's service territory by itself or by county or such other discrete area(s) within its service territory that it deems to be reasonable. Duke Kentucky shall provide an update of this process in its annual Vegetation Management Plan ("VMP") filings beginning with the 2019 VMP.

Planned Outage Expense

Duke Kentucky's forecasted test year included $8.400 million in East Bend planned outage expense, which was calculated based on the average of the actual expense for years 2013 through 2016 and forecast expense for years 2017 and 2018.[50] Duke Kentucky also requests authority to defer any actual planned outage expense that is more or less than the normalized planned outage expense included in its base rates.

The Attorney General contends that the amount is excessive because Duke Kentucky failed to include the forecast expense for 2019, which would have reduced the average amount of planned outage expenses to $7.200 million.[51] The Attorney General recommends reducing Duke Kentucky's revenue requirement by $1.200 million for the planned outage expense.[52] The Attorney General also recommends denying Duke Kentucky's request for a new accounting deferral mechanism for its planned outage

[50] Duke Kentucky's response to Staff's Second Request, Item 23.

[51] Kollen Testimony at 16.

[52] *Id.* at 17.

expense, arguing that such a mechanism would remove any incentive for Duke Kentucky to minimize planned outage costs.

The Commission finds that Duke Kentucky's planned outage expense should be reduced by $1.223 million based on Commission precedent of using the average of four historical and four projected years for the calculation.[53] The Commission also finds Duke Kentucky's request for a deferral mechanism is reasonable and should be approved.

Incentive Compensation

Duke Kentucky included $1.634 million of incentive compensation plan expense tied to financial performance in its test year.[54] The Attorney General recommends reducing Duke Kentucky's incentive compensation expense tied to Duke Kentucky's financial performance by $1.634 million.[55]

Duke Kentucky argues that its incentive compensation plans are designed to be market-based and competitive and that disallowing recovery of a portion of its compensation program would place Duke Kentucky at a competitive disadvantage and hinder its ability to attract the talent the company needs to run a safe, efficient, and reliable electric system.[56] Duke Kentucky asserts that the earnings-per-share ("EPS") or total-shareholder-reward metrics, whether tied to long-term or short-term incentive compensation, encourage eligible employees to reduce expenses, operate efficiently,

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[53] Duke Kentucky's response to Staff's Post-Hearing Request, Item 12.

[54] Kollen Testimony at 21.

[55] *Id.*

[56] Thomas Silinski Rebuttal Testimony ("Silinski Rebuttal Testimony") at 2.

and conserve financial resources, all of which inure to the benefit of ratepayers by keeping rates competitive.[57]

The Attorney General asserts that Duke Kentucky included $0.751 million in Short-Term Incentive Plan expense tied to the achievement of earnings per share and $0.883 million in Long-Term Incentive Plan expense paid in the form of performance shares and restricted stock units tied primarily to Duke Kentucky's financial performance. The Attorney General argues that the Commission has historically disallowed all incentive compensation expenses from the revenue requirement that were incurred to incentivize the achievement of shareholder goals as measured by financial performance.

The Commission is in agreement with the Attorney General on this matter. Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in Case Nos. 2010-00036[58] and 2013-00148,[59] the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find that Duke Kentucky's argument to the contrary does nothing to change this holding, as it is unpersuasive. The Commission finds the Attorney General's position is

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[57] *Id.*

[58] Case No. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010).

[59] Case No. 2013-00148, *Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, (Ky. PSC Apr. 22, 2014).

reasonable and that Duke Kentucky's incentive compensation expense should be reduced by $1.634 million.

Retirement Plan Expense

Duke Kentucky included $1.580 million in retirement plan expense related to its employees or its affiliates' employees who were covered by both a defined dollar benefit ("DDB") plan and a defined contribution ("DC") plan.[60]

The Attorney General recommends reducing Duke Kentucky's retirement plan expense by $1.584 million based on recent decisions in which the Commission denied recovery of retirement expenses in which a utility made contributions to both a DDB pension plan and a DC plan for certain employees.[61]

Duke Kentucky contends that the Attorney General has offered no justification as to why the company's test-year retirement plan expense is unreasonable.[62] Duke Kentucky argues that it has significantly reduced retirement-related expenses by transitioning many employees eligible for pension benefits from a DDB plan to a less rich formula and partially utilizing those pension savings to enhance DC 401(k) matching formulas.[63] Duke Kentucky states that it has aggressively managed costs related to its retirement benefits program by closing the DDB pension plans to new hires, and, for existing employees, lock and freezing final average pay benefit formulas for all non-union employees and transitioning those employees from a final average pay formula to a more

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[60] Duke Kentucky's response to Staff's Post-Hearing Request, Item 4.

[61] Kollen Testimony at 19–21.

[62] Silinski Rebuttal Testimony at 9.

[63] *Id.*

"Defined Contribution like" cash balance benefit formula.[64] Lastly, Duke Kentucky asserts that its benefits packages, including retirement programs, as a whole are designed to be market competitive and are benchmarked to ensure that is the case.[65]

The Commission is in partial agreement with Duke Kentucky on this issue and concludes that Duke Kentucky's retirement plan expense should be accepted as proposed. However, the Commission notes that the changes Duke Kentucky has made to the DDB pension plan were not applicable to union employees.[66] We will not make a distinction between union and non-union employees at this time in order to provide Duke Kentucky an opportunity to address these costs prior to its next base rate case, as rate recovery of these duplicative pension contributions for union employees will be evaluated for appropriateness as part of its next base rate case.

AMI Benefit Levelization Adjustment

Duke Kentucky incorporated an AMI benefit levelization adjustment, as required by the stipulation approved by the Commission in Case No. 2016-00152,[67] of $2.321 million.[68] However, Duke Kentucky's calculation of the AMI benefit was based on the net present value annual savings forecast for the five years from 2018 through 2022.

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[64] Duke Energy Kentucky Inc.'s Brief at 57.

[65] *Id.* at 9–10.

[66] Duke Energy Kentucky Inc.'s Brief at 57.

[67] 2016-00152, *Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief* (Ky. PSC May 25, 2017).

[68] Kollen Testimony at 21.

The Attorney General contends that the economic analysis conducted by Duke Kentucky and reflected in the stipulation in Case No. 2016-00152 represents a savings period of 15 years.[69] The Attorney General argues that Duke Kentucky unilaterally shortened the benefits period in providing the AMI benefit adjustment in this case, causing the adjustment to be reduced.[70] The Attorney General maintains that using a 15-year benefits period results in an increase in the AMI levelization adjustment to $3.177 million. This reflects an increase of $0.856 million from the $2.321 million calculated by Duke Kentucky.

Based on the changes made by Duke Kentucky to the AMI levelization calculation to reflect a full 15-year benefits period, Duke Kentucky maintains that the maximum adjustment the Commission should make to Duke Kentucky's request is $0.855 million if the Attorney General's position is accepted.[71]

The Attorney General filed Errata Testimony for Lane Kollen and, based on the changes made during discovery, amended his AMI benefit levelization adjustment to a revenue requirement reduction of $0.858 million.

Given the parties changes in position and the small difference in the amount of the AMI benefit levelization adjustment, the Commission finds that the levelization adjustment should be based on cost savings before gross-up of $0.855 million.

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[69] *Id.* at 22.

[70] *Id.*

[71] Rebuttal Testimony of William Don Wathen, Jr., at 11.

East Bend O&M Expense Regulatory Asset

Duke Kentucky is seeking to recover the East Bend O&M expense regulatory asset in the amount of $4.490 million, based on a levelized recovery of the $36.540 million regulatory asset over 10 years using Duke Kentucky's forecasted cost of debt.[72] This correction reduced the East Bend O&M expense related to the regulatory asset by $0.323 million. Duke Kentucky also provided an adjustment in rebuttal reducing its revenue requirement by $1.555 million to reflect the debt return that is already accruing on the regulatory asset at Duke Kentucky's long-term debt rate.[73]

The Attorney General argues that Duke Kentucky's forecast deferrals from January 2017 through March 2018 are excessive.[74] The Attorney General recommends that the regulatory asset be reduced to reflect the actual deferrals through October 2017, and to revise the forecast so that it is consistent with the actual monthly deferrals for the 12 months ending October 2017.[75] The Attorney General thus recommends that Duke Kentucky's revenue requirement be reduced by $0.406 million.

The Commission finds that Duke Kentucky's adjustment for the East Bend O&M regulatory asset amortization is more accurate as it is based upon corrections made to the Attorney General's calculation. Therefore, the Commission finds that no further adjustment is warranted for this issue.

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[72] Amended Rebuttal Testimony of Wathen and Waller, Errata Sheet at 1.

[73] Amended Rebuttal Testimony of Sarah E. Lawler at 1.

[74] Kollen Testimony at 29.

[75] *Id.* at 30-31.

Depreciation Expense

Duke Kentucky proposes, as part of developing its depreciation rates, the continued use of the ELG procedure. The Attorney General recommends the Commission adopt the ALG procedure in developing Duke Kentucky's depreciation rates. The Attorney General contends that the ALG methodology is the predominant method that is used in the electric industry for developing depreciation rates. The Attorney General contends that, under the ELG methodology, the capital recovery periods are accelerated and shortened and, thus, the depreciation rates are greater than if the ALG procedure was used.[76] The Attorney General argues that the ALG procedure is as accurate as the ELG procedure and the ALG procedure smooths the data so that the depreciation rates for the group of assets tend to remain constant.[77] Use of the ALG procedure will result in a decrease in Duke Kentucky's depreciation expense of $6.920 million.

Duke Kentucky requested an increase in depreciation expense of $6.920 million, based on its request to utilize the ELG procedure for computing depreciation rates. As was discussed in the rate base section of this Order, this Commission has found that the ELG procedure does not accurately match revenues and expenses, is front-loaded, and Duke Kentucky is the only Kentucky based utility that utilizes the ELG procedure for computing depreciation rates.

Regulatory accounting requires the proper matching of revenues and expense in order to produce fair, just and reasonable rates. The Commission finds Duke Kentucky's

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[76] *Id.* at 33.

[77] *Id.* at 35

proposed ELG procedure does not meet that criteria and that Duke Kentucky's depreciation expense should be reduced by $6.920 million.

Terminal Net Salvage – Generation Units

Duke Kentucky included an adjustment of its depreciation expense of $4.506 million to reflect the impact of terminal net salvage value.[78] Duke Kentucky's proposed depreciation rates reflect terminal net salvage, which the company contends is required under the Federal Energy Regulatory Commissions' Uniform System of Accounts.[79] Duke Kentucky further contends that, to avoid intergenerational inequity, these costs should be borne by those ratepayers who receive the benefit from the production assets.[80]

The Attorney General recommends reducing the proposed depreciation rates by removing terminal net salvage from production plant depreciation rates. The Attorney General argues that Duke Kentucky's proposed recovery of future terminal net negative salvage for production plant is unreasonable because those costs are not known with reasonable certainty today.[81] The Attorney General's recommendation is to reduce Duke Kentucky's depreciation expense by $4.506 million.[82]

The Commission finds Dukes Kentucky's recommendation on the treatment of terminal net salvage value in the computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved.

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[78] *Id*. at 42.

[79] John J. Spanos Rebuttal Testimony ("Spanos Rebuttal Testimony") at 4–5.

[80] Spanos Rebuttal Testimony at 4.

[81] Kollen Testimony at 39.

[82] *Id*. at 42.

Interim Net Salvage

Duke Kentucky proposed a $4.617 increase in depreciation expense to reflect the impact of interim net salvage value in its depreciation rates.[83] Duke Kentucky included interim net salvage based on forecasts of the future cost of removal and salvage income.[84]

The Attorney General contends that Duke Kentucky's methodology front-loads forecasted costs based on limited data applied to the interim retirement portion of the production plant accounts and the entirety of the transmission and distribution plant accounts.[85] By presuming to recover costs that have not and may not be incurred, the Attorney General argues that Duke Kentucky's methodology overstates depreciation rates and expense. The Attorney General recommends applying a methodology that calculates the interim net salvage based on the same historical data used by Duke Kentucky, but uses the average annual historic interim net salvage dollars divided by the interim retirement portion of the production plant account and the entirety of the transmission and distribution plant accounts, rather than the annual historic retirements. Under the Attorney General's recommended methodology, Duke Kentucky's depreciation expense would decrease by $4.617 million.

The Commission finds Duke Kentucky's recommendation for the treatment of interim net salvage value in the computing of its depreciation rates to be reasonable to avoid intergenerational inequity and should be approved.

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[83] *Id.* at 45.

[84] *Id.* at 43.

[85] *Id.* at 44.

Federal Income Tax Expense

In its rebuttal testimony, Duke Kentucky proposed a reduction in Federal Income Tax ("FIT") of $10.623 million to reflect the impacts of the TCJA.[86] Duke Kentucky states that the adjustment is due to updating the gross-revenue conversion factor ("GRCF") for the decrease in the federal income tax rate.[87] The Attorney General proposed a $10.255 million reduction to reflect the impact of the TCJA, using the same methodology.[88]

The Commission has carefully reviewed the parties' methodology and computations in determining their respective FIT impacts of the TCJA. The Commission finds the Attorney General's calculations to be more accurate and therefore will reduce Duke Kentucky's revenue requirement by $10.255 million.

Excess Deferred Taxes

Duke Kentucky proposed a reduction in its revenue requirement of $3.782 million to reflect the impact of the TCJA on the amortization of its excess ADIT.[89] The Attorney General proposed a reduction of $6.054 million. Both Duke Kentucky and the Attorney General utilized the ARAM method to compute the amortization of the protected excess ADIT and both parties originally utilized a 20-year amortization for the unprotected excess ADIT. As was discussed in the rate base section of this Order, the Commission has accepted the ARAM calculation of the protected excess ADIT and has found a ten-year amortization period for the unprotected excess ADIT to be reasonable. As a result, the

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[86] Sarah E. Lawler Rebuttal Testimony ("Lawler Rebuttal Testimony") at 3.

[87] *Id.*

[88] Kollen Testimony at 48.

[89] Lawler Rebuttal Testimony at 3.

Commission finds that Duke Kentucky's test-year federal income tax expense should be reduced by $4.472 million to reflect this adjustment.

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, Duke Kentucky's adjusted net operating income is as follows:

Operating Revenues	$308,549,356
Operating Expenses	270,589,404
Adjusted Net Operating Income	$ 37,959,952

Capitalization

Duke Kentucky's proposed capitalization represents the end-of-year balances of the 13-month average for the test period ending March 31, 2019. Because Duke Kentucky's total capitalization is for its electric and gas operations, the amount allocated to its electric operations is determined by taking the total capitalization for both electric and gas and applying the electric rate base ratio.[90] This is consistent with the approach used in previous Duke Kentucky rate cases. Accordingly, the total capitalization allocated to its electric operations is $705,051,140.[91]

The Attorney General recommended several adjustments to Duke Kentucky's capitalization. Each adjustment was made proportionally based upon Duke Kentucky's capital ratio for a final capitalization of $647,314,275.[92] No other intervenor

[90] *See* Application, Work Papers, WPA1 d for the electric rate base ratio.

[91] Direct Testimony of Sarah E. Lawler ("Lawler Testimony") at 5.

[92] Kollen Testimony, Exhibit 23.

recommended any capitalization adjustment. The Attorney General proposed the following adjustments:

- A reduction of $5.126 million for loans Duke Kentucky made to other Duke Energy affiliates as a member of Duke Energy Money Pool ("Money Pool"). The Money Pool is used to meet short-term cash requirements and the Attorney General states that Duke Kentucky should not be allowed a return on these investments because if the revenue requirements were calculated using rate base this Money Pool investment would be excluded. The Attorney General adjusted the capitalization downward by Duke Kentucky's forecasted test year Money Pool investments, reducing Duke Kentucky's revenue requirement by $0.451 million.[93] In its rebuttal testimony, Duke Kentucky states that the money pool is used to manage short-term cash positions and any reduction to its capitalization should be solely attributed to the short-term debt portion of the capital structure and not applied proportionally based on its capital ratio of short-term debt, long-term debt, and common equity.[94] The Commission agrees that any adjustment should be made solely to short-term debt and will adjust the capitalization downward for a revenue reduction of $0.158 million.[95]

- A reduction of $39.162 million to reflect the removal of the East Bend O&M expense regulatory asset. The Attorney General argues that Duke Kentucky has already included a debt-only rate of return in the levelized amortization expense for the East Bend O&M expense regulatory asset and in the revenue requirement. The adjustment reduces

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[93] *Id.* at 51–52.

[94] Rebuttal Testimony of Stephen G. De May at 17–18.

[95] This adjustment alters the capitalization ratio. Further adjustments are made to this revised capitalization.

Duke Kentucky's revenue requirement by $3.449 million. In its rebuttal testimony, Duke Kentucky agrees to remove this regulatory asset from capitalization and, in response to Duke Kentucky's Post-Hearing Data Request, the projected East Bend O&M Expense regulatory asset was updated to $36.540 million.[96] Removing this updated amount from the Commission adjusted capitalization results in a decrease in the revenue requirement of $3.231 million.

- The removal of the demand-side management ("DSM") regulatory asset for a reduction of $1.477 million from the capitalization and a reduction in the revenue requirement of $0.130 million. The Attorney General states that Duke Kentucky erred by not removing the DSM regulatory asset from its electric capitalization. Duke Kentucky counters that all DSM revenue and expenses have been removed, but the deferred balance should not be removed as it is exclusively related to a cash flow issue and is financed by shareholders and recommended rejecting this adjustment as it is an asset on Duke Kentucky's balance sheet and is not accruing carrying costs.[97] The Commission agrees that the DSM regulatory asset is a cash flow issue and rejects the proposed adjustment.

- The removal of $18.509 million from capitalization for the East Bend coal ash regulatory asset as the Attorney General proposed that these costs be recovered through the proposed Environmental Surcharge Mechanism Rider. The impact of this adjustment is a reduction in Duke Kentucky's revenue requirement of $1.630 million.

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[96] Duke Kentucky's Response to Staff's PH–DR, Item 2.

[97] Rebuttal Testimony of Sarah E. Lawler ("Lawler Rebuttal") at 7.

Duke Kentucky agreed with this adjustment.[98] The Commission finds this proposed adjustment to be reasonable and will remove this from the Commission's adjusted capitalization, which results in a decrease of $1.637 million in the revenue requirement.

- An increase to the revenue requirement of $0.018 million to reflect a $0.200 million increase to capitalization to account for the impact of amortizing the Carbon Management Research Group regulatory asset over a ten-year period as compared to Duke Kentucky's proposed five-year period. Duke Kentucky agrees with this recommendation and the Commission finds this adjustment to be reasonable and should be accepted. This adjustment increases the revenue requirement by $0.018 million on the Commission's adjusted capitalization.

- An increase of $2.733 million to reflect the reduction in depreciation expense resulting from use of the ALG depreciation method instead of Duke Kentucky's proposed ELG depreciation method. As stated earlier, the Commission agrees with the application of the ALG methodology in developing Duke Kentucky's depreciation rates and, accordingly, accepts the corresponding adjustment to capitalization. Based on the revised capitalization, the revenue impact is $0.242 million.

- The Attorney General recommends Duke Kentucky's revenue requirement be increased $0.157 million to reflect the $1.780 million increase in capitalization resulting from the reduction in depreciation expense from the proposed removal of terminal net salvage value. As stated earlier, the Commission rejected the Attorney General's recommendation on this issue and, therefore, no corresponding adjustment to capitalization will be made.

[98] Duke Kentucky's Response to the Attorney General's Second Request for Information, Item 4e.

- An increase of $1.824 million to capitalization to reflect the increased capitalization resulting from the reduction in depreciation expense from the proposed removal of the remaining net salvage. The Commission rejected the Attorney General's recommendation on this issue and, therefore, no corresponding adjustment to capitalization will be made.

Appendix B illustrates the impact of each capitalization adjustment. The total Commission approved adjustments lower Duke Kentucky's electric operations capitalization to $647,809,050.

Rate of Return, Capital Structure, and Cost of Debt

Duke Kentucky proposed a test-year-end capital structure consisting of 40.68 percent long-term debt at a cost of 4.24 percent; 10.43 percent short-term debt at a cost of 3.08 percent; and 48.89 percent common equity with a proposed return of 10.30 percent.[99] Although the capitalization is lower, the capital structure proposed by the Attorney General maintains the same capital ratios and short-term and long-term debt costs but adjusts the cost of common equity. Neither NKU, KSBA, nor Kroger addressed the capital structure.

Return on Equity

In its application, Duke Kentucky developed its proposed return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the Empirical CAPM model, and Risk Premium analysis ("RP"). Derived from these cost of capital evaluations, Duke Kentucky proposed an ROE range, adjusted for flotation costs, of 9.0 percent to 10.7 percent, and recommended an ROE be awarded within the

[99] Application, Schedule J-1, page 2.

upper half portion of this range, or between 9.9 and 10.7 percent.[100] Duke Kentucky used the midpoint of this upper portion, or 10.3 percent, in calculating its revenue requirements. Duke Kentucky maintained that an ROE in this range fairly compensates investors, maintains Duke Kentucky's credit strength and attracts the capital needed for utility infrastructure and reliability capital investments.[101] Duke Kentucky further emphasized that an ROE in the upper portion of the recommended range accounts for the high external financing risks facing Duke Kentucky relative to its small size, forecasted increases in interest rates, a highly concentrated generation mix, and a higher degree of regulatory risk.[102] The table below summarizes Duke Kentucky's ROE estimates:[103]

STUDY	ROE
DCF – Value Line Growth	9.4%
DCF – Analyst Growth	9.0%
CAPM	9.5%
Empirical CAPM	10.0%
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

Direct testimony and analysis regarding the ROE were also provided by the Attorney General. The Attorney General employed the DCF and CAPM models for its analysis but based its recommendation on the results of the DCF model.[104] The Attorney General used 19 proxy companies as compared to the 23 Duke Kentucky utilized. The Attorney General stated that due to significant events, including acquisition activity,

[100] Direct Testimony of Roger A. Morin, PhD ("Morin Testimony") at 4.

[101] *Id*. at 5.

[102] *Id*. at 4.

[103] *Id*. at 62.

[104] Direct Testimony of Richard A. Baudino ("Baudino Testimony") at 3.

natural disasters, and capital investment cancellations, the exclusion of the four proxy companies was warranted.[105] In the DCF model, the Attorney General employed both the average and the median values for the expected growth rates. The model results indicated equity cost rates ranging from 8.07 percent to 9.16 percent for the average growth rates and for the median growth rates, 8.19 percent to 9.21 percent. The Attorney General recommended removing the low end of the average growth range, stating that 8.07 percent appeared to be understated and that the remaining DCF estimates reflect a range of approximately 8.2 percent to 9.2 percent. Thus, the Attorney General recommended a point slightly higher than the midpoint, or 8.8 percent.[106]

The Attorney General disagreed with Duke Kentucky's overall analysis, stating that Duke Kentucky's requested ROE is overstated, inconsistent with the current low–interest-rate environment, and not supported by current market evidence.[107] In particular, the Attorney General disagreed with Duke Kentucky's DCF analysis, arguing that Duke Kentucky's exclusion of forecasted dividend growth in the DCF analysis, due to Duke Kentucky's concern regarding slower dividend growth in the near term was not reflective of long-run expected earnings growth. The Attorney General also questioned Duke Kentucky's use of 1+g to calculate the expected dividend yield as compared to 1+.5g. The Attorney General noted that although the two approaches do not yield significantly different results, the 1+g approach is overstated as it assumes an investor receives the

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[105] *Id.* at 19. The four companies were Avista Corp. (which had announced that it would be acquired by Hydro One); PG&E Corp. (which recently announced that it would be eliminating its common and deferred stock dividends); SCANA (who's stock price has fallen significantly due to the cancellation of the Summer nuclear power plant); and Sempra Energy (which recently announced its acquisition of Oncor).

[106] *Id.* at 31.

[107] *Id.* at 32.

full amount of growth throughout the next year and given the timing of dividend increases and the level of the dividend, the investor may or may not actually receive a full year of increased dividend payments.[108]

The Attorney General's CAPM results range from 7.01 percent to 7.23 percent for the forward-looking CAPM ROE estimates and 6.02 percent to 7.39 percent using historical risk premiums.[109] The Attorney General stated that Duke Kentucky's CAPM analysis employed an inflated projected interest rate, and that current interest rates and bond yields embody all relevant market data and expectations of investors.[110] He further argues that the use of the Empirical CAPM analysis is not a reasonable method to use for Duke Kentucky's ROE estimate, as the use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas are incorrect and investors should not rely on them.[111] The Attorney General rejects the RP analysis calling it imprecise and stating that it should only be used for general guidance.[112]

Finally, the Attorney General disagreed with Duke Kentucky's inclusion of an upward adjustment for flotation costs. The Attorney General notes that flotation costs attempt to collect the costs of issuing common stock and that these costs are already accounted for in current stock prices and that adding an adjustment for flotation costs

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[108] *Id.* at 34.

[109] *Id.* at 30.

[110] *Id.* at 34.

[111] *Id.* at 39.

[112] *Id.* at 40.

amounts to double counting.[113] The Attorney General further notes that if flotation costs are excluded from the Duke Kentucky's DCF analysis, the cost of equity results fall to a range of 8.86 percent to 9.27 percent.[114]

In its rebuttal testimony, Duke Kentucky contends that the Attorney General's proposed ROE would be one of the lowest authorized returns in the industry, that it lies outside the zone of reasonableness, and, if adopted, would cause adverse consequences to Duke Kentucky's creditworthiness, financial integrity, capital-raising ability and ultimately to its customers. Duke Kentucky further disagrees with the Attorney General exclusively relying on the results of the DCF analysis and the procedures and methodologies used in his analysis.

In his post-hearing brief, the Attorney General pointed out that in the recent Kentucky Power Company ("Kentucky Power") rate case,[115] the Commission noted that the increase in interest rates is happening slowly and interest rates are still historically low. He also noted that the Commission stated that models supporting a low-interest-rate environment should be given more weight. The Attorney General contends that Duke Kentucky did not provide any evidence to sway this Commission from that position and that an ROE of 8.8 percent should be adopted.[116] Duke Kentucky's post-hearing brief

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[113] *Id.* at 33.

[114] *Id.*

[115] Case No. 2017-00179, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service, (2) An Order Approving its 2017 Environmental Compliance Plan; (3) An Order Approving its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) An Order Granting All Other Required Approvals and Relief* (Ky. PSC Jan. 18, 2018).

[116] Attorney General's Post Hearing Brief at 5–6.

contends that the Attorney General's proposed ROE is unreasonable and lies outside the zone of currently authorized ROEs for electric utilities.[117] For the reasons discussed below, the Commission finds a ROE of 9.725 percent to be reasonable, and for the purpose of base rate revenues and certain tariffs, an ROE of 9.725 percent should be applied.

The Commission agrees that financial markets are still in a low–interest-rate environment. However, economic data indicates a healthy outlook with steady growth, low unemployment, and inflation at the Federal Reserve's ("Fed") target level. Citing a solid economic outlook, the Fed increased the federal funds interest rate to 1.75 percent this past March, the highest level in a decade, and signaled that two to three more rate hikes are possible in 2018. Increased government spending, the possible impact of current tariff policy on net imports, and the Tax Cut and Jobs Act of 2017 should all contribute to a healthier economy. These macroeconomic inputs point to a robust outlook and an economy that has recovered from the Great Recession. However, notwithstanding these improvements, interest rates are still historically low, the impact of interest rate changes is unpredictable, and increases in the federal funds rate are not guaranteed.

The Commission agrees with the Attorney General that flotation costs should be excluded from the analysis as they are already accounted for in the current stock prices. Removal of the flotation costs from Duke Kentucky's ROE model produces the following results:

[117] Duke Kentucky's Post-Hearing Brief at 73.

STUDY	ROE
DCF – Value Line Growth	9.3%[118]
DCF – Analyst Growth	8.9%[119]
CAPM	9.3%[120]
Empirical CAPM	9.8%[121]
Historical Risk Premium	10.5%[122]
Allowed Risk Premium	10.5%[123]

For 2017, the average authorized ROE in the electric utility industry as reported in the Regulatory Research Associates ("RRA") quarterly review was 9.80 percent, and the average of allowed ROEs for the proxy group of 19 companies is 9.88.[124] Further, the Commission notes its last award of 9.7 percent for an investor-owned electric utility. The Commission believes these ROE reports are benchmarks worthy of consideration in determining a reasonable ROE. The Commission believes that since its last award of 9.7 percent, the economy has shown quantifiable signs of improvement. Further, the Commission recognizes the risk inherent to Duke Kentucky's lack of diversity in its generation fleet. Based on the entire record developed in this proceeding, we find that the approved ROE of 9.725 falls within the range of Duke Kentucky's proposed ROE of 8.86 percent to 10.5 percent, adjusted for flotation costs. While the ROE of 9.725 exceeds the Attorney General's range of 8.2 percent to 9.2 percent, the Commission believes that

[118] Morin Testimony at 30.

[119] *Id.* at 31.

[120] *Id.* at 44.

[121] *Id.* at 47.

[122] *Id.* at 49.

[123] *Id.* at 52. No flotation cost is noted.

[124] *Id.* *See also*, Rebuttal Testimony of Roger A. Morin, PhD at 10.

the Attorney General recommended range is unreasonably low. The Commission agrees with Duke Kentucky that awarding an ROE that is significantly lower than other electric utility authorized ROEs may cause it financial stress and fails to take into account Duke Kentucky's highly concentrated generation portfolio. Additionally, an ROE of 9.725 is within the range of the benchmarks provided by RRA and approved for the proxy group, and recognizes the economic improvements since the last Commission decisions involving rate cases of other investor-owned electric utilities in Kentucky.

Rate-of-Return Summary

Applying the rates of 3.08 percent for short-term debt, 4.24 percent for long-term debt, and 9.725 for common equity to the Commission adjusted capital structure consisting of 9.77 percent, 40.98 percent, and 49.25 percent, respectively, produces an overall cost of capital of 6.83 percent.[125]

Base Rate Revenue Requirement

The Commission has determined that, based upon Duke Kentucky's capitalization of $647,809,050 and an overall cost of capital of 6.83 percent, Duke Kentucky's net operating income that could be justified by the evidence of record is $44,245,358. Based on the adjustments found reasonable herein, Duke Kentucky's pro forma net operating income for the test year is $37,959,952. Therefore, Duke Kentucky would need an increase in annual base rate operating income of $6,285,406. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, Duke Kentucky would have a base-rate electric revenue deficiency of $8,428,645.

The calculation of this base-rate revenue deficiency is as follows:

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[125] *See*, Appendix B.

Net Operating Income Found Reasonable	$ 44,245,358
Pro Forma Net Operating Income	37,959,952
Net Operating Income Deficiency	$ 6,285,406
Gross Revenue Conversion Factor	1.3409866
Base Rate Revenue Deficiency	$ 8,428,645

REVENUE ALLOCATION AND RATE DESIGN

Cost of Service Study ("COSS") and Revenue Allocation

Duke Kentucky prepared three fully embedded COSSs in this proceeding that contain essentially the same data, except that different methodologies were used to develop the allocation factor for the demand component of Production-related costs. The demand allocation methods are as follows: (1) 12-CP method; (2) the Average and Excess method; and (3) the Summer/NonSummer method. Of those three, Duke Kentucky recommends using the 12-CP methodology, stating that it is generally accepted in the utility industry and was approved by the Commission in its most recent electric base rate case.[126] Using the 12-CP method, the allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of what their respective loads were at other times of the day. Duke Kentucky states that due to an anticipated future replacement of its billing system, it is not seeking to implement any significant rate design changes. Duke Kentucky is proposing to increase customer charges and energy charges and, where applicable, demand charges, across the board. Duke Kentucky's proposed rate design is based upon its 12-CP COSS

[126] Case No. 2006-00172, Duke Kentucky (Ky. PSC Dec. 21, 2006).

increases are supported by the COSS.[127] For the residential class, the customer charge is proposed to increase from $4.50 to $11.10, or 147 percent.[128] This amount represents nearly the full customer charge as calculated by the COSS.[129] Duke Kentucky is also proposing to increase its street lighting and traffic lighting rates. The revised proposed increase by rate class is as follows:[130]

Rate RS	14,780,440
Rate DS	7,870,484
Rate GS-FL	51,793
Rate EH	54,744
Rate SP	1,897
Rate DT-Secondary	3,854,808
Rate DT-Primary	2,442,311
Rate DP	105,930
Rate TT	807,689
Lighting	146,956
Total	30,117,052

The Attorney General's witness, Mr. Glenn Watkins, prepared two COSSs but stated that he accepts Duke Kentucky's 12-CP method for evaluating class profitability. While Mr. Watkins stated that he believes that Duke Kentucky's revenue distribution is reasonable for the residential class, he states that Duke Kentucky's proposed revenue allocation produces anomalous results for several nonresidential classes but did not offer any suggested changes. In addition, Mr. Watkins calculated a customer charge between

[127] As originally proposed, the customer charges for rate class DT, both Primary and Secondary, were not supported by the COSS. However, through discovery, Duke Kentucky proposed that the customer charges be revised to reflect the COSS.

[128] As revised in the billing analysis provided in Duke Kentucky's response to Staff's PH-DR, Item 9.

[129] The revised COSS filed by Duke Kentucky in response to Staff's PH-DR, Item 8, supports a residential customer charge of $11.31.

[130] *See* revised billing analysis provided in Duke Kentucky's response to Staff's PH-DR, Item 9, Tab Sch M-2.2.

any suggested changes. In addition, Mr. Watkins calculated a customer charge between $2.69 and $3.49 using "a direct customer cost analysis" and objected to any increase in the residential customer charge. Mr. Watkins asserts that Duke Kentucky's proposed residential rate design violates the principle of gradualism, the theory of efficiency competitive prices and is contrary to effective conservation efforts.

NKU did not object to Duke Kentucky's 12-CP COSS and did not oppose Duke Kentucky's revenue allocation. Kroger's witness, Mr. Justin Bieber, proposed that the Commission allocate 50 percent of the benefits of the tax impact to all rate classes and then use the remaining 50 percent to further reduce interclass subsidies, as he believes the proposed 10 percent subsidy reduction is insufficient. Duke Kentucky believes Mr. Bieber's proposal is not a fair result for its customers, stating the changes due to the tax reduction should follow the customer contribution to costs.

The Commission accepts Duke Kentucky's revised 12-CP COSS to use as a guide in determining revenue allocation and rate design. The Commission also accepts Duke Kentucky's proposed revenue allocation and finds that the proposed revenue allocation, which reduces class subsidies by 10 percent, conforms to the principle of gradualism. As previously stated, the Commission is granting less of an increase than that requested by Duke Kentucky. Therefore, the Commission will allocate the increase granted herein on a proportional basis to each of the rate classes, based generally on Duke Kentucky's proposed revenue allocation.

Rate Design

Duke Kentucky's revised 12-CP COSS supports a residential customer charge in the amount of $11.31, which includes all costs identified as customer-related in its

COSS.[131] This method of calculating the customer charge is generally accepted in the utility industry and is being accepted by the Commission. Although the Commission has been reluctant to approve an increase in the residential customer charge in excess of 50 percent due to the principle of gradualism, we believe that a larger increase is warranted in this proceeding given Duke Kentucky's lowest-in-Kentucky current residential customer charge of $4.50 and the amount of time that has passed since the charge was established. Therefore, the Commission will approve a residential customer charge of $11.00. Given the reduction to the requested increase granted herein, allocating the entirety of the increase authorized for the residential class to the customer charge will not achieve an $11.00 customer charge. Therefore, the Commission will decrease the current residential energy charge in order to establish an $11.00 customer charge and achieve the increase authorized for the residential class. The Commission will also accept Duke Kentucky's proposed customer charges and demand charges for the nonresidential rate classes, as revised. Therefore, in order to achieve the decrease in the requested increase granted herein, the Commission has adjusted the energy charges of all rate classes. The monthly increase for the residential class results in an increase of 3.2 percent, or approximately $2.56, for a typical residential customer using 1,000 kWh of electricity per month.

PROPOSED TARIFF CHANGES

Fixed Bill Program. Duke Kentucky is proposing to offer a Fixed Bill program to its customers. A customer signing up for the Fixed Bill program would pay a flat monthly billing charge for electric service for 12 months. The flat monthly charge would include a

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[131] Duke Kentucky's Response to Staff's PH-DR, Item 8, Attachment, Tab Customer Charge.

premium in order to take into account the risk of weather and commodity volatility. Duke Kentucky stated that the premium has not yet been finalized for inclusion in the program but that, if approved, the premium to be charged to customers would be determined and added to the applicable section in the compliance tariff.[132] Duke Kentucky also states that significant changes in the customer's consumption behavior may require the Fixed Bill amount to be recalculated before the 12-month period ends. If a customer's actual usage is more than 30 percent higher than their expected weather-adjusted usage, Duke Kentucky stated that it would send them a warning letter and, if the excessive usage continues, the company would have the right to remove the customer from the program or adjust their fixed bill amount to reflect the increased usage.[133] At the end of 12 months, Duke Kentucky would calculate a new charge to the customer, which will factor in any changes in usage patterns for the customer. The customer would be required to re-enroll in the Fixed Bill payment option every 12 months.

Duke Kentucky's initial proposed tariff did not contain the provisions of the Fixed Bill Program but Duke Kentucky indicated that it would be willing to include the provisions of the Fixed Bill Program in its tariff if the program is approved.[134]

Mr. Watkins, the Attorney General's witness, filed testimony recommending that the Fixed Bill Program be rejected. Mr. Watkins stated that the Fixed Bill program is not in the public interest and provides windfall profits to Duke Kentucky with no realistic benefits to consumers. Mr. Watkins also states that the Fixed Bill program would provide

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[132] Duke Kentucky's Response to Staff's Fourth Request for Information ("Staff's Fourth Request"), Item 17 b.

[133] Duke Kentucky's Response to Staff's Fourth Request, Item 17. a.

[134] Duke Kentucky's Response to Commission Staff's Second Request for Information ("Staff's Second Request"), Item 9 d.

benefits to consumers. Mr. Watkins also states that the Fixed Bill program would provide for a constant "flat" bill to customers regardless of how much energy they consume or when they consume it, and that policies such as this are contrary to the objectives of efficient pricing.

The Commission finds that the Fixed Bill Program is not reasonable and should not be approved. A jurisdictional utility must charge its filed rates for usage and the Commission finds that this program does not adhere to the Commission's filed rate doctrine. Because Duke Kentucky included $122,230 in the forecasted test year as the amount of premium associated with this program, in rejecting the Fixed Bill Program, the Commission has made an adjustment to increase the revenue requirement by $122,230.

Rate RTP-M, Real-Time Pricing. Duke Kentucky is proposing to cancel and withdraw Rate RTP-M, Real-Time Pricing – Market-Based Pricing. Duke Kentucky states that this rate option has not been utilized by any customers since its inception and that it was proposed when Duke Kentucky purchased all of its power from Duke Energy Ohio, which is no longer the case. Duke Kentucky states that it has another RTP tariff available for nonresidential customers. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate TT, Time of Day Rate – Transmission Voltage. Duke Kentucky is proposing to add a summer and winter on-peak energy rate similar to Rate DT. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate DT, Time of Day Rate – Distribution Voltage. Duke Kentucky is proposing to remove language referencing an expired optional pilot rate for low load factor customers from this tariff. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate LED, LED Outdoor Lighting Service. Duke Kentucky is proposing to introduce a LED lighting tariff due to increased customer requests for LED fixtures. The minimum term for the tariff is proposed to be 10 years. The rates proposed by Duke Kentucky included a carrying charge based on a 10.30 percent ROE. As previously stated, the ROE approved in this proceeding is 9.725 percent. Therefore, the Commission has recalculated the proposed LED rates using a ROE of 9.725 percent. With this recalculation of rates, the Commission finds that the proposed LED lighting tariff is reasonable and should be approved.

Rate OL, Outdoor Lighting Service. Duke Kentucky is proposing to cancel and withdraw Rate OL, Outdoor Lighting Service. Per Duke Kentucky's current tariff, this rate schedule terminated December 31, 2016. Duke Kentucky is proposing that all remaining participants be moved to Rate UOLS, Unmetered Outdoor Lighting and, as applicable, Rate OL-E – Outdoor Lighting Equipment Installation. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate NSP, Private Outdoor Lighting Service for Nonstandard Units. Duke Kentucky is proposing to cancel and withdraw Rate NSP, Private Outdoor Lighting for Non-Standard Units. Per Duke Kentucky's current tariff, this rate schedule terminated December 31, 2016. Duke Kentucky is proposing that all remaining participants be moved to Rate UOLS, Unmetered Outdoor Lighting and, as applicable, Rate OL-E, Outdoor Lighting Equipment Installation. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

<u>Rider LM, Load Management Rider.</u> Duke Kentucky is proposing to revise Rider LM to reflect the fact that it no longer utilizes the magnetic tape recording devices included in Section II of the Rider. Section II will be eliminated and all participants utilizing interval data recorders and time-of-use meters will be combined under Section I.[135] There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

<u>Rate MDC, Meter Data Charges.</u> Duke Kentucky is proposing to revise Rate MDC to clarify that it is for nonresidential customers and to rename it Meter Data Charges for Enhanced Usage Data Services. In addition, the name of the software that enables the service is changed from EnFocus to Energy Profiler Online (EPO).[136] There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

<u>Rider GSS, Generation Support Service.</u> Duke Kentucky is proposing to combine the Monthly Distribution Reservation Charge, Monthly Transmission Reservation Charge, and Monthly Ancillary Services Reservation Charge values into a combined value called Monthly Transmission and Distribution Reservation Charge.[137] Duke Kentucky clarified

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[135] Direct Testimony of Bruce L. Sailers ("Sailers Testimony") at 17.

[136] Sailers Testimony at 20.

[137] Sailers Testimony at 20.

in the discovery and at the hearing in this matter that proposed Rider GSS does not include a Monthly Ancillary Services Reservation Charge.[138] There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rider FAC, Fuel Adjustment Clause. Duke Kentucky is proposing to include additional PJM Interconnection, LLC ("PJM") Billing Line Items for recovery through its FAC. Duke Kentucky's proposal is the same, with respect to the PJM billing line items, as was made by Kentucky Power in its recent base-rate proceeding and approved by the Commission.[139] There were no objections to this tariff change from the intervenors. The Commission will approve Duke Kentucky's proposal with the requirement that Duke Kentucky list each of the PJM billing line items that will flow through the FAC in its compliance tariff.

Rider PSM, Off-System Sales Profit Sharing Mechanism. Duke Kentucky is proposing changes to its Rider PSM to expand the categories of revenues (net of costs) available for inclusion in Rider PSM and to streamline the administration and calculation of Rider PSM. Duke Kentucky is proposing to make adjustments to Rider PSM to reflect PJM billing line items that are related to credits and charges attributable to the off-system sales shared with customers under Rider PSM. Duke Kentucky is proposing to adjust the categories of eligible net proceeds (credits and charges) that can be flowed through the PSM to include all wholesale energy, capacity, and ancillary services markets (net of costs and credits) that are now available or may become available in PJM. This will

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[138] Duke Kentucky's response to Staff's Fourth Request, Item 14, and March 7, 2018 hearing at 2:07:45.

[139] Case No. 2017-00179, Kentucky Power (Ky. PSC Jan. 18, 2018).

capacity performance market requirements and for short-term capacity purchases necessary to meet Duke Kentucky's three-year fixed resource requirement plan. Duke Kentucky is also proposing to include costs of any capacity payments made to cogeneration facilities under the terms of its cogeneration tariffs, as well as any net proceeds from the sale of renewable energy certificates derived from any Company-owned renewable generating resources. Since Duke Kentucky is proposing to implement an environmental surcharge mechanism, cost recovery and the sharing of any gains or losses on the sale of emission allowances will begin to be addressed in Rider ESM.[140] None of the intervenors filed testimony objecting to the expansion of items proposed to be included in Rider PSM. However, in its post-hearing brief, the Attorney General stated that the proposed changes to Rider PSM should be denied because Duke Kentucky has not met its burden as to the necessity of the changes. The Attorney General argued that Duke Kentucky is attempting to turn Rider PSM into a way to pass costs on to customers instead of a way to share profits.

Duke Kentucky is also proposing to revise the sharing percentage between customers and shareholders. Currently, the first $1 million in annual margins from off-system sales flow to customers and anything over $1 million is shared 75 percent to customers and 25 percent to Duke Kentucky shareholders. Duke Kentucky is proposing to revise the sharing percentage between customers and shareholders to a 90/10 split and eliminate the $1 million threshold in the formula. Duke Kentucky argues that the proposed split will simplify and streamline the process. Duke Kentucky also provided

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[140] Direct Testimony of William Don Wathen, Jr. ("Wathen Testimony") at 14 and 15.

calculations showing that the change to Rider PSM would benefit customers during the forecasted period in the amount of $322,294.[141]

The Attorney General did not provide testimony opposing Duke Kentucky's proposed 90/10 customer/shareholder split but did recommend that the forecasted off-system sales margins be removed from Rider PSM and be included in base rates, as discussed previously in this Order.

Having reviewed the record in this proceeding, the Commission finds Duke Kentucky's proposed changes to Rider PSM to be reasonable and will approve Duke Kentucky's proposal with the requirement that Duke Kentucky list each of the PJM billing line items that will flow through Rider PSM in its compliance tariff. In addition, the Commission will require Duke Kentucky to notify the Commission within seven days of incurring any capacity performance assessment from PJM.

Reconnection of Service. Duke Kentucky is proposing to revise its reconnection fees as follows:

Charge	Current Charge	Proposed Charge
Remote Reconnection	$0.00	$25.00
Reconnection (Nonremote, Electric Only)	25.00	75.00
Reconnection (Nonremote, Electric & Gas)	38.00	88.00
Reconnection at pole (Electric Only)	65.00	125.00
Reconnection at pole (Electric & Gas)	90.00	150.00
Collection Fee	15.00	50.00

[141] Duke Kentucky's Response to Staff's Second Request, Item 28.

Duke Kentucky filed cost support for its proposed reconnection charges. In response to questioning from the Attorney General regarding the calculation of the remote reconnection charge, Duke Kentucky offered to revise its remote reconnection charge using an alternate labor rate which would result in a remote reconnection charge of $3.45. Duke Kentucky stated that if this revised rate was approved rather than the proposed rate, a corresponding adjustment totaling $170,759 would need to be made to its revenue requirement to account for the loss of the reconnection revenue.[142]

With the exception of the remote reconnection charge, the Commission finds that the proposed charges in the table above are reasonable and should be approved. The Commission also finds that the remote reconnection charge should be $3.45 and has made an adjustment to increase Duke Kentucky's revenue requirement in the amount of $170,759.

Rate CATV, Rate for Pole Attachments of Cable Television Systems. Duke Kentucky is proposing to increase the pole attachment rates and to broaden the rate language to apply the per foot charge to other pole attachments on a contract basis based on the footage required for the attachment. Duke Kentucky is also proposing that this rate schedule be renamed to Rate DPA, Distribution Pole Attachment Rate, thereby limiting the attachments to distribution poles.[143] There were no objections to this tariff change from the intervenors. The Commission will approve Duke Kentucky's proposed changes to this tariff; however, the rates proposed by Duke Kentucky will not be approved as they were calculated using a rate of return based on a 10.30 percent ROE. Therefore,

[142] Sailers Rebuttal Testimony at 15.

[143] Sailers Testimony at 18.

the Commission has recalculated the proposed pole attachment rates using the Commission approved ROE of 9.725 percent and will approve a two-user-pole rate of $5.92 and a three-user-pole rate of $4.95. Because this change to the proposed pole attachment rates will impact revenue, the Commission has made an adjustment to increase Duke Kentucky's revenue requirement in the amount of $15,601.

<u>Cogeneration and Small Power Production Sale and Purchase Tariffs ("Cogen Tariffs").</u> Duke Kentucky has two Cogen Tariffs, one for cogeneration facilities that are 100 kW or less ("Small Cogen Tariff") and one for cogeneration facilities that are greater than 100 kW ("Large Cogen Tariff"). For the Small Cogen Tariff, Duke Kentucky is proposing to revise the Energy Purchase Rate to reflect avoided energy cost equal to a two-year average PJM Locational Marginal Price ("LMP") at the Duke Energy node. The Energy Purchase for the Large Cogen Tariff is based on the PJM real-time LMP for power at the DEK Aggregate price node for each hour of the billing month.

For both Cogen Tariffs, Duke Kentucky proposes to recover required energy purchases through the FAC as an economy energy purchase. Duke is also proposing to add a Capacity Purchase Rate to both Cogen tariffs that will be based on the Company's avoided capacity cost in Duke Kentucky's last Integrated Resource Plan, which was reviewed in Case No. 2014-00273.[144] Duke Kentucky proposes to adjust the Capacity Purchase Rate after the Commission completes its review of the next IRP, which is due to be filed in June 2018. Due to the fact that Duke Kentucky may need to purchase

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[144] Case No. 2014-00273, *2014 Integrated Resource Plan of Duke Energy Kentucky, Inc.* (Ky. PSC Sept. 23, 2015).

capacity to meet its own resource needs in PJM, it is proposing to reconcile and recover costs of any purchases of capacity under these tariffs through Rider PSM.

Duke Kentucky is also proposing to add language to both of its Cogen Tariffs stating that no capacity purchase will be made if the qualifying facility cannot satisfy the Company's capacity need or the Company does not have a capacity need.

The Commission finds that the proposed changes to Duke Kentucky's Cogen Tariffs should be approved except as discussed below.

Capacity Rate. Duke Kentucky's calculation of the capacity rate used an ROE of 10.3 percent. As the ROE approved in this proceeding is 9.725 percent, the Commission has recalculated the capacity rate using an ROE of 9.725 percent and will approve a capacity rate of $3.61 per kW-month.

Language related to Capacity Purchases. 807 KAR 5:054, Section 6 states, in relevant part, as follows:

> (1) Each electric utility shall purchase any energy and capacity which is made available from a qualifying facility except as provided in subsections (2) and (3) of this section.
>
> (2) The qualifying facility's right to sell power to the utility shall be curtailed in periods when purchases from qualifying facilities will result in costs greater than those which the utility would incur if it generated an equivalent amount of energy instead of purchasing that energy.
>
> (3) During any system emergency, an electric utility may discontinue:
>
> (a) Purchases from a qualifying facility if such purchases would contribute to such emergency; and
>
> (b) Sales to a qualifying facility if discontinuance is nondiscriminatory.

The Commission finds that Duke Kentucky's proposed language stating that no capacity purchase will be made if the qualifying facility cannot satisfy Duke Kentucky's capacity need or when Duke Kentucky does not have a capacity need is inconsistent with the requirements of 807 KAR 5:054, Section 6(1). The regulation requires Duke Kentucky to purchase energy and capacity from a qualifying facility except as set forth in subsections 2 and 3, both of which do not apply in the language proposed by Duke Kentucky. Therefore, the proposed language should not be approved.

In addition, Duke Kentucky is reminded that 807 KAR 5:054, Section 5, requires all electric utilities with annual retail sales greater than 500 million kWhs to provide data to the Commission from which avoided costs may be derived not less often than every two years unless otherwise determined by the Commission.

Rider DCI and Targeted Underground Program. Duke Kentucky requests authority to implement Rider DCI to recover the incremental capital costs, above what is to be included in base rates, for specific Commission-approved programs aimed at accelerating, improving, and enhancing the performance of Duke Kentucky's electric delivery system in terms of reliability and integrity.[145] Duke Kentucky states that Rider DCI is modeled after similar Commission-approved programs for its gas operations as well as similar mechanisms implemented in by its affiliates in Ohio and Indiana.[146] Duke Kentucky explains that it will file an annual application to set and true-up its Rider DCI for the duration of a Commission-approved program.[147] The annual applications will

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[145] Henning Testimony at 24.

[146] *Id.*

[147] *Id.*

establish new rider rates based on the actual incremental investment in the eligible plant in service as of the end of each calendar year. The revenue requirement for the rider will include a return on incremental rate base, income taxes on the equity component of the return, property taxes, and depreciation expense associated with the incremental investment. The rider will not include recovery of incremental O&M expenses. Duke Kentucky is proposing to allocate the resulting revenue requirement based on the allocation factors used for the underground distribution equipment from its COSS.

Duke Kentucky is seeking authority for a CPCN to implement a Targeted Underground program to be included in Rider DCI.[148] Duke Kentucky maintains that due to the advancements in consumer electronics, customer expectations are evolving and customers are requiring a higher degree of reliability, performance, and response with respect to the provision of electric service.[149] As part of its philosophy to evolve to meet new and growing customer demands, Duke Kentucky is proposing to implement a Targeted Underground program, which will identify specific areas of the company's distribution system that experience higher-than-acceptable frequency of outages and replace overhead wires with underground cables to harden the system, thereby increasing reliability.[150] The Targeted Underground program will focus on undergrounding certain small overhead distribution conductors which have been identified as having the highest likelihood of outages within Duke Kentucky's distribution

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[148] *Id.*

[149] Platz Testimony at 20.

[150] Platz Testimony at 25.

system.[151] The types of overhead line segments that have performed worse as compared to the remainder of Duke Kentucky's overhead facilities are remote lines that are located close to trees and certain line segments located along major thoroughfares.[152] Tree-related customer interruptions and public action (i.e., cars crashing into poles) customer interruptions account for 18 percent and 9 percent, respectively, of all customer interruptions for Duke Kentucky.[153] Duke Kentucky states that it will also ultimately take ownership of those underground service lines that are replaced either as part of the Targeted Underground program or existing customer-owned underground service lines that experience a failure and are replaced by Duke Kentucky.[154] Duke Kentucky maintains that hardening these underperforming line segments provides broad benefits for all customers while addressing these poor performing areas.[155] Over the next 10 years, Duke Kentucky expects to spend approximately $67 million as part of its Targeted Underground efforts.[156]

The Attorney General, Kroger, and NKU recommend that Rider DCI be rejected. The Attorney General argues that automatic capital and investment adjustment clauses, such as Rider DCI, are poor policies and do not allow the requisite amount of regulatory review that is provided in a full base-rate proceeding.[157] The Attorney General contends

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[151] Platz Testimony at 25–26.

[152] Platz Testimony at 27.

[153] *Id.*

[154] Platz Testimony at 26.

[155] *Id.*

[156] Platz Testimony at 28–29.

[157] Baudino Testimony at 46.

that Duke Kentucky has failed to quantify any customer benefits associated with either Rider DCI or the Targeted Underground Program.[158] The Attorney General also contends that the areas that have been identified by Duke Kentucky as experiencing higher than average outages should be considered a high priority and addressed by the company as part of its normal budgeting and system operations regardless of the existence of Rider DCI.[159] Should the Commission consider approving Rider DCI, the Attorney General recommends that the Commission take the following into consideration: 1) Rider DCI should be limited to a three-year pilot program; 2) Duke Kentucky should only be allowed to include actual investment costs after the year they are closed to plant in service; 3) the inclusion of a yearly 2.5 percent cap on rate increases associated with Rider DCI; 4) the inclusion of a cumulative cap of 5 percent on rate increases from Rider DCI between base rate cases; and 5) offsets that reflect the build-up of accumulated depreciation and ADIT associated with investments included in Rider DCI during the period that the mechanism is in effect.[160]

NKU states that Duke Kentucky has not demonstrated that the costs to be recovered through Rider DCI are volatile, unpredictable, or outside its control.[161] NKU argues that the risk of recovery of these costs is mitigated by Duke Kentucky's use of a forecasted test year and that, to the extent the projects that would be recovered under Rider DCI are prudent projects that are beneficial to consumers, Duke Kentucky should

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[158] Baudino Testimony at 47.

[159] Baudino Testimony at 49.

[160] Baudino Testimony at 52–54.

[161] Direct Testimony of Brian C. Collins at 14.

plan the projects as part of the normal capital budgeting process and include the project costs in future rate cases.[162]

Kroger argues that the proposed DCI rider amounts to single-issue ratemaking and reduces Duke Kentucky's incentive to manage its costs effectively, particularly with respect to the proposed Targeted Underground program.[163]

On rebuttal, Duke Kentucky asserts that recovery of any costs associated with the proposed Targeted Underground program through Rider DCI will be subjected to greater scrutiny because those would be the only costs that would be the subject of review in any Rider DCI proceeding.[164] Duke Kentucky avers that in these separate rider proceedings, the company would have more detailed cost estimates for the near-term work to be performed and would not be able to recover costs until the plant was in service.[165] Thus, according to Duke Kentucky, the Commission would have greater transparency into how Duke Kentucky's program is impacting reliability performance for customers.[166] Further, Duke Kentucky maintains that it would have the burden of proof that any new program would be reasonable and performed at a reasonable cost prior to cost recovery being included in Rider DCI.[167]

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[162] *Id.*

[163] Bieber Testimony at 4, 13–14.

[164] Rebuttal Testimony of Anthony J. Platz ("Platz Rebuttal") at 3.

[165] *Id.*

[166] *Id.*

[167] Platz Rebuttal at 5.

Duke Kentucky also takes issue with the Attorney General's argument that the company has failed to quantify the benefits of the proposed Targeted Underground program, noting that the company provided those quantifications in response to the Attorney General's discovery requests, which were referenced by one of the Attorney General's witnesses in the pre-filed testimony.[168] Duke Kentucky argues that the Targeted Underground program would reduce major event day ("MED") outage events by 16 percent and reduce MED outage duration by 15–20 percent.[169]

Having reviewed the record, the Commission finds that Duke Kentucky has failed to establish a need for either Rider DCI or the Targeted Underground program. Rider DCI and the Targeted Underground program are designed to improve and enhance Duke Kentucky's electric distribution system and to allow Duke Kentucky timely cost recovery of those investments. The record, however, indicates that Duke Kentucky's electric distribution system is performing well based on customer expectations and reliability metrics. As noted in the pre-filed testimony of Mr. James P. Henning and according to a J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study, the overall satisfaction scores of Duke Kentucky Energy Midwest, which includes Duke Kentucky, outperformed both the Midwest Region average scores and the large utility industry average, finishing in the second quartile among large utilities nationally.[170] The J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study calculates overall

[168] Platz Rebuttal at 5–6.

[169] Platz Rebuttal at 7.

[170] Henning Testimony at 13; *See also*, Henning Testimony, Exhibit JPH–1.

customer satisfaction based on six performance areas.[171] One of those performance areas is power quality and reliability, which was weighted the highest at 28 percent.[172]

In addition, Duke Kentucky conducts internal customer satisfaction studies, which surveys residential customers who have had a recent service interaction with the company.[173] The internal customer satisfaction surveys show that Duke Kentucky customers were highly satisfied overall with the services provided by Duke Kentucky and that the level of customer satisfaction was either steady or improving.[174] In particular, one of the processes measured in the internal customer satisfaction study was outage restoration and experiences.[175] The study indicates that 77 percent of Duke Kentucky residential customers were highly satisfied with their overall outage and restoration experience.[176]

Lastly, Duke Kentucky witness Anthony J. Platz testified that Duke Kentucky's distribution system has performed well and that the company's reliability scores have exceeded industry average reliability scores and are among the best performing throughout Duke Energy's six-state electric service areas.[177]

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[171] Henning Testimony at 12.

[172] Henning Testimony, Exhibit JPH–1 at 2 of 17.

[173] Henning Testimony at 13.

[174] Henning Testimony at 14.

[175] Henning Testimony at 14–15.

[176] Henning Testimony, Exhibit JPH–2 at 2–3 of 24.

[177] Platz Testimony at 13–15. Duke Kentucky's 2016 Customer Average Interruption Duration Index ("CAIDI"), which measures the average interruption duration or average time to restore service per interrupted customer was 130 minutes, excluding major event days. Duke Kentucky's 2016 System Average Interruption Duration Index ("SAIDI"), which measures the average time each customer was interrupted, 99 minutes, excluding major event days. Duke Kentucky's 2016 System Average Interruption Frequency Index ("SAIFI"), which measures the average number of interruptions that a customer would experience, was 0.76 interruptions, excluding major event days.

Duke Kentucky states that Rider DCI is modeled after its existing riders to recover costs associated with the accelerated replacements of gas pipeline mains and service lines. We note, however, that the need to have a surcharge mechanism to timely recover the substantial investments required to replace aging and bare steel gas pipelines with polyethylene pipelines was based on a public safety concern that those gas pipelines be replaced on an accelerated schedule in order to minimize the risk of a catastrophic pipeline failure. In the instant proceeding, Duke Kentucky has identified no critical system-wide need to justify the implementation of a surcharge to recover costs associated with improvements to the company's distribution system. We note that the proposed Targeted Underground program targets only discrete sections of Duke Kentucky's distribution system that have experienced higher outage occurrences as compared to the rest of the company's distribution system.[178] The Targeted Underground program would impact approximately 5,600 customers over the next 10 years, but at a cost of almost $67 million.[179] While Duke Kentucky projects that there will be a reduction in MED outage events by 16 percent and a reduction in MED outage duration by 15–20 percent, the Targeted Underground program would have no impact on the projected frequency of system outages as measured by SAIFI and would have very little impact in the projected duration of a customer's outage as measured by SAIDI.[180] Given the absence of a need

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[178] Duke Kentucky identified approximately 140 miles of overhead distribution lines that will need to be placed underground and approximately 5,600 customers impacted by the Targeted Underground program over the next 10 years. *See*, Duke Kentucky's response to the Attorney General's Second Data Request, Item 41.

[179] Platz Testimony at 28 – 29.

[180] Duke Kentucky's response to the Attorney General's First Data Request, Item 89. Duke Kentucky forecasted that system-wide SAIDI would improve by from 66 minutes to 60 minutes due to the Targeted Underground program.

and the limited impact of the proposed Targeted Underground program and Rider DCI, the Commission finds that any such distribution related improvements should be performed by Duke Kentucky as part of its normal operations and those costs should be recovered in base rates and not through a surcharge mechanism.

Rate UDP-R, Underground Residential Distribution Policy. Duke Kentucky is proposing to add language to this tariff to create the ability for the Company to pay for and own, with revenues to be recovered through Rider DCI, underground installations associated with the Targeted Underground program. Since neither Rider DCI nor the Targeted Underground program are being approved, the Commission denies this tariff change.

Rate UDP-G, General Underground Distribution Policy. Duke Kentucky is proposing to add language to this tariff to create the ability for the Company to pay for and own, with revenues to be recovered through Rider DCI, underground installations associated with the Targeted Underground program. Since neither Rider DCI nor the Targeted Underground program are being approved, the Commission denies this tariff change.

Rate RTP. Duke Kentucky is proposing to combine the energy delivery charge and ancillary services charge. Duke Kentucky is also proposing to correct the reference to the "PJM Real-Time Total Locational Marginal Price" to "PJM Day-Ahead Total Locational Marginal Price." There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rider FTR, FERC Transmission Cost Reconciliation Rider. Duke Kentucky is proposing to implement Rider FTR, which is intended to recover or credit specific PJM transmission costs. The specific costs include network integration transmission service, both firm and non-firm point-to-point market administration fees, and potentially other transmission costs that may be billed in the future related to serving retail load that is above or below the level included in the Company's base rates established in this proceeding. Duke Kentucky is also proposing that the rider track incremental changes in costs associated with PJM's Regional Transmission Expansion Plan costs that are incremental to what the Company is proposing to include in its base rates.[181]

On a quarterly basis, Duke Kentucky proposes to adjust Rider FTR based on the most recent actual monthly invoices received from PJM. Duke Kentucky also proposes to submit to an annual review of this rider by the Commission of the invoiced costs and the revenue collected under the rider. The rider will be filed 30 days before it is scheduled to go into effect.[182]

Both the Attorney General and NKU filed testimony recommending that Rider FTR be rejected by the Commission. The Attorney General's witness, Mr. Lane Kollen, states that the rider would increase the retail revenue requirement in real time based on net expense pursuant to FERC tariffs, and would change recovery from a fixed amount based on the test-year expense revised with periodic base rate increases to a series of automatic quarterly Rider FTR rate increases. Mr. Kollen also states that Rider FTR "would change

[181] Wathen Testimony at 18.

[182] Wathen Testimony at 19.

Duke Kentucky's incentives to attempt to influence these expenses or to reduce other expenses to compensate for the increases in these expenses due to the selective single nature of these expenses."[183] NKU witness Mr. Brian Collins argues that Duke Kentucky has not demonstrated that the incremental transmission costs not included in base rates proposed to be recovered through Rider FTR would significantly impact Duke Kentucky's ability to earn its authorized rate of return.

After reviewing the evidence of record in this proceeding, the Commission finds that Duke Kentucky's proposed Rider FTR should not be approved. Although the Commission is aware that it recently approved a similar rider for Kentucky Power in Case No. 2017-00179, the decision in that proceeding was based on evidence which demonstrated that Kentucky Power's transmission costs were significant and volatile; therefore, the approval of such a rider was warranted in that proceeding. Duke Kentucky testified during the hearing in this matter that Duke Kentucky's transmission rates are significantly less than those for Kentucky Power and "the volatility has a much bigger impact" on Kentucky Power than Duke Kentucky.[184] The Commission finds no evidence in this proceeding to suggest that the proposed FTR is warranted for Duke Kentucky at this time.

<u>Budget Payment Plan.</u> Duke Kentucky's current and initially proposed tariff do not comply with 807 KAR 5:006, Section 14(2)(a)(3), which requires that the provisions of the budget payment plan be included in a utility's tariffed rules. Through discovery, Duke

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[183] Kollen Testimony at 62.

[184] March 7, 2018 Hearing at 3:50:48.

Kentucky indicated that it would be willing to include the provisions of the budget payment plan in its tariff.[185] Duke Kentucky is directed to do so when filing its compliance tariff.

Pick Your Own Due Date and Usage Alerts and Outage Alerts with AMI. Duke Kentucky is proposing to implement a pick your own due date billing option and a Usage Alerts and Outage Alerts with AMI service; however, Duke Kentucky did not include the provisions of these items in its proposed tariff. Through discovery, Duke Kentucky indicated that it would be willing to include the provisions of these programs/services in its tariff.[186] Duke Kentucky is directed to do so when filing its compliance tariff.

Miscellaneous Tariff Changes. Duke Kentucky is proposing various minor text changes to its tariff. Unless otherwise stated in this Order, the Commission finds that the proposed changes are reasonable and should be approved.

Bill and Bill Format. Duke Kentucky is proposing to update its bill format to reflect the riders proposed in this case and the new company logo. The Commission approves Duke Kentucky's proposal to change its bill format to the extent that the bill reflects the riders and rates approved herein.

Duke Kentucky's tariff contains its bill format, which consists of three pages. However, when Duke Kentucky bills its customers, it does not include page 2, which contains the billing details, unless the customer checks a block that indicates he or she would like to receive page 2. The Commission finds that page 2 provides customers with the ability to check the accuracy of the bill and should be sent to every customer. With this Order, the Commission will require the entire bill be sent to every customer, thereby

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[185] Duke Kentucky's Response to Staff's Second Request, Item 9 c.

[186] Duke Kentucky's Response to Commission Staff's Third Request for Information ("Staff's Third Request"), Item 6 b.

eliminating the requirement that the customer elect to receive the entire bill. This directive applies to all Duke Kentucky customers, including those that are gas customers only.

Tariff Format. Numerous tariff pages Duke Kentucky submitted in this case did not appear to comply with 807 KAR 5:006, Section 3(4), which states "[e]ach tariff sheet shall contain a blank space at its bottom right corner that measures at least three and one-half (3.5) inches from the right of the tariff sheet by two and one-half (2.5) inches from the bottom of the tariff sheet to allow space for the commission to affix the commission's stamp." This ensures that no language is obscured by the Commission's stamp. When filing its compliance tariff reflecting the rates, rules, and terms of service approved in this Order, Duke Kentucky should ensure that all of its tariff pages comply with 807 KAR 5:006, Section 3(4).

Rider DSM, Demand-Side Management. The Commission finds that, upon the implementation of new base rates, the Lost Revenue from Lost Sales Recovery component of Duke Kentucky's DSM cost-recovery rider should be reset to zero. Duke Kentucky's compliance tariff should reflect this revision to Rider DSM.

KSBA Recommendations. The KSBA made certain recommendations that the Commission will address herein.

1. Elimination of Demand Ratchet from Rate DS. KSBA witness Mr. Ron Willhite recommends that the Commission eliminate the demand ratchet from Rate DS for P–12 public and private schools or alternatively minimize the demand ratchet for said schools billed under this rate schedule. KSBA argues that Duke Kentucky is a summer peaking utility and that schools are not typically in session during the summer peak but peak during the month of September. As a result, because of the demand ratchet for

Rate DS, a school's September billing demand becomes the basis for demand billing in many of the non-summer revenue months. Mr. Willhite states that schools billed under Rate DS are subsiding other customers within the class and that the demand ratchet for schools should be eliminated or reduced. As an alternative, Mr. Willhite suggests the establishment of a new P–12 School Tariff. Duke Kentucky opposes the creation of a new P–12 School Tariff, stating that Mr. Willhite provided no information that specifically demonstrates how the energy demand requirements of schools are substantially dissimilar from other Rate DS Rate DS.

The Commission is not convinced that public school usage characteristics support special treatment compared to other customers serviced under Rate DS and will not approve KSBA's recommendation.

2. Rate SP, Seasonal Sports Service. KSBA recommends that the Commission allow some sports fields to move to Rate SP. Currently, Rate SP is a closed tariff and has been closed since June 25, 1981. According to KSBA, subsequent to 1981new sports fields are being served on Rate DS and must pay a demand charge and minimum payments based on off-peak night-time load in the months they are not in full operation. KSBA argues that sports fields clearly are not similar to other commercial and industrial loads served on Rate DS. KSBA states that it is aware of three sports fields that are interested in taking service under the closed tariff. Duke Kentucky is opposed to reopening the tariff, stating that KSBA has not met the burden of proof to establish the reasonableness of re-opening Rate SP.

At the hearing in this matter, Duke Kentucky could not explain why the tariff was closed or whether it had been reopened temporarily over the intervening years. In its post-hearing brief, Duke Kentucky stated that it was closed due to lack of interest and has remained closed since 1981. The Commission finds that the load for sports fields would differ significantly from that of other customers and that Duke Kentucky should be directed to reopen Rate SP permanently. Given that there will be a revenue impact to Duke Kentucky if current customers move to Rate SP, the Commission will allow Duke Kentucky to defer the difference between what it would have billed the sports field customer under its current rate and what it will bill under Rate SP as a regulatory asset and request recovery in its next base-rate proceeding.

3. Funding for SEMP, School Energy Manager Program. KSBA recommends that the Commission require Duke Kentucky to fund the SEMP through shareholder funds. Mr. Willhite states that public schools must pursue energy savings pursuant to KRS 160.325 and that SEMP has significantly improved cost savings for schools in the territories of other jurisdictional utilities. Duke Kentucky opposes Mr. Willhite recommendation, stating that he does not "offer any evidence that shows the Company's choice not to fund SEMP to date has somehow prevented school districts in the Company's service territory from moving forward with meaningful energy efficiency programs."[187]

The Commission agrees with Duke Kentucky on this issue and will not approve KSBA's recommendation to require Duke Kentucky to fund SEMP.

2018 ENVIRONMENTAL COMPLIANCE PLAN AND ENVIRONMENTAL SURCHARGE

[187] Duke Kentucky's Post-Hearing Brief at 119–120.

As part of this proceeding, Duke Kentucky filed an application, pursuant to KRS 278.183, for authority to establish and assess an environmental surcharge rider ("Rider ESM") and for approval of its environmental compliance plan ("2018 Plan").[188] KRS 278.183 provides that a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act ("CAA") as amended and those federal, state, or local environmental requirements that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Pursuant to KRS 278.183(2), a utility seeking to recover its environmental compliance costs through an environmental surcharge must first submit to the Commission a plan that addresses compliance with the applicable environmental requirements. The plan must also include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of the proposed surcharge applied to individual rate classes. Within six months of submission, the Commission must conduct a hearing to:

(a) Consider and approve the compliance plan and rate surcharge if the plan and rate surcharge are found reasonable and cost-effective for compliance with the applicable environmental requirements;

(b) Establish a reasonable return on compliance-related capital expenditures; and

(c) Approve the application of the surcharge.

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[188] Duke Kentucky's Application and witness testimony refers to the environmental compliance plan as the 2017 Plan. In prior compliance plan orders, the Commission has named the plan according to the year in which the order is issued. Accordingly, the Commission will refer to the subject environmental compliance plan as the 2018 Plan.

The 2018 Environmental Compliance Plan

As required by KRS 278.183, Duke Kentucky filed its 2018 Plan, consisting of five projects necessary to comply with the CAA or other environmental regulations applicable to coal combustion wastes and by-products. Duke Kentucky's 2018 Plan reflects environmental compliance costs at its only coal-fired generation facility, East Bend. The projects include:[189]

1. Project EB020290 Lined Retention Basin West;
2. Project EB020745 Lined Retention Basin East;
3. Project EB020298 East Bend SW/PW Reroute;
4. ARO amortization for Pond Closure; and
5. Consumables (Reagents and emission allowances).

The 2018 Plan includes projects that were previously approved Case Nos. 2015-00187[190] and 2016-00398.[191] At the time of the filing of this case, two projects at East Bend were in progress, with planned in-service dates after the test period in this proceeding.[192]

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[189] Application at 16.

[190] Case No. 2015-00187, *Application of Duke Energy Kentucky Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations* (Ky. PSC Dec. 15, 2015). The Commission approved Duke Kentucky's proposed accounting treatment to classify ARO costs for the East Bend Ash Pond, including amortization and depreciation expenses, closure costs, and carrying charges on the unamortized balance as regulatory assets for 2015 and subsequent years ("East Bend Coal Ash ARO regulatory asset").

[191] Case No. 2016-00398, *Electronic Application of Duke Energy Kentucky, Inc. for a Certificate of Public Convenience and Necessity Authorizing the Company to Close the East Bend Generation Station Coal Ash Impoundment and for All Other Required Approvals and Relief* (Ky. PSC June 6, 2017). Duke Kentucky received certificates of public convenience and necessity to close and repurpose its existing East Bend ash impoundment and construct new water redirection and wastewater treatment systems.

[192] Application at 17. Construction has begun for the process water system and pond repurposing projects.

Duke Kentucky states that the pollution control projects included in the 2018 Plan amendment are necessary for Duke Kentucky to comply with the CAA and other federal, state, and local regulations, which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal.

Environmental Requirements

Clean Air Interstate Rule and Cross-State Air Pollution Rule. The Clean Air Interstate Rule ("CAIR") and Cross-State Air Pollution Rule ("CSAPR") are regional rules that set state-level annual standards for the emission of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") from electric generating units.[193] Published in the Federal Register on October 26, 2016, the CSAPR Update reduced the number of ozone season NO_x allowances for East Bend effective January 1, 2017.[194] The East Bend selective catalytic reduction controls and allowances from Duke Kentucky's retired Miami Fort Unit 6 station are expected to comply with the CSAPR Update, but East Bend can also buy allowances on the market if necessary.[195]

CCR Rule. Coal combustion residuals ("CCRs") include fly ash, bottom ash, and flue-gas desulfurization byproducts. The Disposal of Coal Combustion Residuals from Electric Utilities Final Rule ("CCR Rule") was published as a Subtitle D, nonhazardous waste rule on April 17, 2015. The CCR Rule includes dam safety requirements for ash ponds and new requirements for the handling, disposal, and beneficial reuse of CCRs

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[193] Direct Testimony of Tammy Jett ("Jett Testimony") at 5.

[194] *Id.*

[195] *Id.* at 6.

except when reused in encapsulated applications, such as concrete and wallboard.[196] Together with the Steam Electric Effluent Limitation Guidelines Final Rule ("ELG Rule"), the CCR Rule requires dry handling of fly and bottom ash, increased use of landfills, closure of existing wet ash storage ponds, and alternative wastewater treatment systems.[197]

ELG Rule. The ELG Rule was published on November 3, 2015, and sets requirements for wastewater streams, including fly ash and bottom ash wastewaters, at steam electric generating units.[198] Compliance activities include converting ash handling systems from wet to dry handling and clean closure of the existing East Bend Ash Pond. The ELG Rule compliance deadline was originally set for November 1, 2018, through December 31, 2023, but has been stayed as the EPA requests reconsideration. However, East Bend's compliance projects schedules are not impacted, as the ELG Rule was not the only driver.[199]

RIDER ESM

Duke Kentucky is proposing a new tariff to implement Rider ESM. Through discovery, Duke Kentucky was made aware of inconsistencies in the Rider ESM tariff and proposed changes through rebuttal testimony to make the tariff consistent with the proposed mechanism.[200] The Commission finds that the tariff as discussed and modified

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[196] Jett Testimony at 11–12.

[197] *Id.* at 12.

[198] *Id.* at 12–13.

[199] *Id.*

[200] Lawler Rebuttal at 12–13.

in this order should become effective for service rendered on and after the date of this order.

Costs Associated with the 2018 Plan. Duke Kentucky proposes to recover the costs associated with the amortization of the East Bend Coal Ash ARO regulatory asset, including projected costs, on a levelized basis over ten years.[201] The Attorney General recommends that the Commission authorize recovery of current ARO–related costs in the second month after they are incurred and of amortization of only previously incurred costs.[202] The Attorney General explains that KRS 278.183(2) allows recovery of environmental compliance costs "in the second month following the month in which they are incurred" and, furthermore, that recovery of ARO–related costs before they are actually incurred would result in increased current income tax expense and negative deferred income tax expense, which would increase E(m).[203] The Commission concurs with the Attorney General that KRS 278.183 does not allow for recovery of projected or estimated costs. Therefore, the Commission finds that Duke Kentucky should amortize only the actual balance of the East Bend Coal Ash ARO regulatory asset over 10 years and recover additional actual costs associated with the settlement of the East Bend Coal Ash ARO in the second month after they are incurred.

Duke Kentucky has identified the environmental compliance costs for the 2018 Plan projects and these are the costs that Duke Kentucky proposes to recover through

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[201] Lawler Testimony at 11–12.

[202] Kollen Testimony at 60.

[203] *Id.* at 59–60.

its environmental surcharge. Duke Kentucky has removed these costs from the base period and excluded these costs from its forecasted period in this proceeding to ensure that no costs are recovered through its base rates and Rider ESM.[204] The costs identified here by Duke Kentucky, as modified above, are eligible for surcharge recovery if they are shown to be reasonable and cost-effective for complying with the environmental requirements specified in KRS 278.183. The Commission finds that the costs identified for the 2018 Plan projects have been shown to be reasonable and cost-effective for environmental compliance. Thus, they are reasonable and should be approved for recovery through Duke Kentucky's environmental surcharge.

Qualifying Costs. The qualifying costs included in E(m) will reflect only the Commission-approved environmental projects from the 2018 Plan. Should Duke Kentucky desire to include other environmental projects in the future, it will have to apply for an amendment to its approved compliance plan.

Rate of Return. As specified in this order, Duke Kentucky is authorized to use a 9.725 percent return on equity that will be utilized in Rider ESM to determine the Weighted Average Cost of Capital ("WACC").

Capitalization and Gross Revenue Conversion Factor. As specified in this order and proposed by Duke Kentucky, Duke Kentucky should utilize a WACC of 6.830 percent and a gross revenue conversion factor ("GRCF") of 1.337304[205] in determining the rate of return to be used in the monthly environmental surcharge filings. Duke Kentucky

[204] Application at 17 and Lawler Testimony at 9.

[205] Lawler Rebuttal, Attachment SEL-Rebuttal-2(b), page 3 of 11. Duke Kentucky's proposed GRCF has been updated for the 21 percent federal income tax rate.

proposes to update the WACC and GRCF when it files a base rate case. The WACC and GRCF should remain constant until such time as the Commission sets base rates in Duke Kentucky's next base rate case proceeding.

Surcharge Mechanism and Calculation. As proposed by Duke Kentucky, the environmental revenue requirement ("E(m)") is comprised of a return on the environmental compliance rate base, plus specified environmental compliance operating expenses, less proceeds from emission allowance sales, plus or minus prior period adjustments as determined by the Commission during six-month and two-year review cases, plus or minus surcharge over- or under-recovery adjustments.[206] Environmental compliance rate base is defined as electric plant in service for specified environmental compliance projects adjusted for accumulated depreciation, accumulated deferred income taxes, accumulated investment tax credits, construction work in progress, and emission allowance inventory.

To calculate the monthly Rider ESM factor, Duke Kentucky proposes to divide the E(m) by the average revenues excluding Rider ESM revenue of the preceding 12-month period ("R(m)").

Surcharge Allocation. Duke Kentucky proposes to allocate the E(m) to residential[207] and nonresidential[208] rate schedules on the basis of the percentage of total

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[206] Lawler Rebuttal, Attachment SEL-Rebuttal 1(b).

[207] *Id.* Residential includes the following rate schedules: Residential Service.

[208] *Id.* Nonresidential includes the following rate schedules: Service at Secondary Distribution Voltage, Optional Rate for Electric Space Heating, Seasonal Sports Service, Service at Primary Distribution Voltage, Time-of-Day Rate for Service at Distribution Voltage, General Service Rate for Small Fixed Loads, Time-of-Day Rate for Service at Transmission Voltage, Street Lighting Service, Traffic Lighting Service, Unmetered Outdoor Lighting, Street Lighting Service for Nonstandard Units, Street Lighting Service – Customer Owned, Street Lighting Service – Overhead Equipment, and LED Outdoor Lighting Service.

R(m) for the 12-month period ending with the current expense month. Rider ESM will be implemented as a percentage of R(m) for the Residential rate schedule and as a percentage of R(m) excluding fuel revenues for Nonresidential rate schedules.[209]

Duke Kentucky proposes to utilize a jurisdictional allocation ratio of 100 percent to allocate E(m) to native retail customers because Duke Kentucky has no firm wholesale customers and PJM Manual 15 does not allow nonvariable production costs to be included in offer cost components.[210] The Commission finds this argument unpersuasive.[211] The jurisdictional allocation ratio should be calculated as total jurisdictional retail revenues excluding Rider ESM revenues, divided by total company revenues excluding Rider ESM revenues, consistent with all other electric utilities that have an environmental surcharge mechanism pursuant to KRS 278.183.

Monthly Reporting Forms. Duke Kentucky provided proposed monthly reporting forms to be used in the monthly environmental reports.[212] Duke Kentucky provided revised forms to make clerical adjustments and revisions necessary to align the forms with the revised Rider ESM tariff.[213] The Commission finds that Duke Kentucky's proposed monthly environmental surcharge reporting forms, as revised through testimony and this order, should be approved.

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[209] Lawler Rebuttal at 12.

[210] Lawler Testimony, Attachment SEL-2, page 2 of 10, and Duke Kentucky's response to Commission Staff's Third Request for Information ("Staff's Third Request"), Item 3.

[211] *See* Case No. 1994-00332, *The Application of Louisville Gas and Electric Company for Approval of Compliance Plan and to Assess a Surcharge Pursuant to KRS 278.183 to Recover Costs of Compliance with Environmental Requirements for Coal Combustion Wastes and By-Products* (Ky. PSC Apr. 6, 1995), Order Denying Rehearing at 1–2.

[212] Lawler Testimony, Attachment SEL-2.

[213] Lawler Rebuttal, Attachments SEL-Rebttual-2(a) and SEL-Rebuttal-2(b).

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by Duke Kentucky are denied.

2. The rates and charges, as set forth in Appendix C to this Order, are approved as fair, just, and reasonable rates for Duke Kentucky and these rates and charges are approved for service rendered on and after April 14, 2018.

3. Duke Kentucky's depreciation rates, as modified herein, are approved.

4. Duke Kentucky's proposal for a deferral mechanism for planned outage expense is approved.

5. Duke Kentucky's request to amortize the East Bend O&M regulatory asset over a ten-year period is approved.

6. Duke Kentucky's carrying charges on the East Bend O&M regulatory asset shall be based on its cost of debt.

7. Duke Kentucky request to amortize the East Bend Ash Pond ARO over a ten-year period is approved.

8. Duke Kentucky proposal for a deferral mechanism for replacement power expense is approved.

9. Duke Kentucky, in conjunction with DEBS, shall bid the next MAVMS contract for the Midwest market that includes Kentucky, Indiana, and Ohio and for a smaller geographic area limited to Duke Kentucky's service territory. The smaller geographic area shall include Duke Kentucky's service territory by itself or by county or such other discrete area(s) within its service territory that it deems to be reasonable. Duke Kentucky shall also provide an update of this process in each annual VMP filings beginning with the 2019 VMP.

10. Duke Kentucky's request to implement a Fixed Bill Program is denied.

11. Duke Kentucky's request to cancel and withdraw Rate RTP – M is approved.

12. Duke Kentucky's request to revise Rate TT as discussed herein is approved.

13. Duke Kentucky's request to revise Rate DT as discussed herein is approved.

14. Duke Kentucky's request to revise Rate LED is approved as modified herein.

15. Duke Kentucky's request to cancel and withdraw Rate OL is approved.

16. Duke Kentucky's request to cancel and withdraw Rate NSP is approved.

17. Duke Kentucky's request to revise Rate LM as discussed herein is approved.

18. Duke Kentucky's request to revise Rate MDC as discussed herein is approved.

19. Duke Kentucky's request to revise Rider GSS as discussed herein is approved.

20. Duke Kentucky's request to revise Rider FAC is approved as directed herein.

21. Duke Kentucky's request to revise and modify Rider PSM is approved as directed herein. Duke Kentucky shall notify the Commission within seven days of incurring any capacity performance assessments from PJM.

22. Duke Kentucky's request to modify its reconnection fees is approved as modified herein.

23. Duke Kentucky's request to revise Rate CATV is approved as modified herein.

24. Duke Kentucky's request to revise its Cogen Tariffs is denied in part and granted in part. Duke Kentucky's request to include language in its Cogen Tariffs limiting capacity purchases from qualifying facilities is denied. Duke Kentucky's request to revise its capacity rate is approved as modified herein. All other proposed revisions to the Cogen Tariffs are approved.

25. Duke Kentucky's request to implement Rider DCI is denied.

26. Duke Kentucky's request for a CPCN to implement the Targeted Underground program is denied.

27. Duke Kentucky's request to make revisions to Rate UDP – R and Rate UDP – G related to the Targeted Underground program is denied.

28. Duke Kentucky's request to revise Rate RTP as discussed herein is approved.

29. Duke Kentucky's request to implement Rider FTR is denied.

30. Duke Kentucky's 2018 Environmental Compliance Plan is approved.

31. Duke Kentucky shall file its Budget Payment Plan tariff in compliance with 807 KAR 5:006, Section 14(2)(a)(3).

32. Duke Kentucky shall provide to each of its customers, including gas only customers, the entire content of its bills as provided in its tariff.

33. Duke Kentucky shall ensure that all of its tariff pages comply with 807 KAR 5:006, Section 3(4) when filing its compliance tariff reflecting the rates, rules, and terms of service approved herein.

34. Duke Kentucky shall reopen Rate – SP to allow any sports field to receive service under this rate schedule. Duke Kentucky shall be authorized, for accounting purposes only, to defer the difference between what it would have billed the sports field customer under its current rate and what it will bill under Rate SP as a regulatory asset.

35. Duke Kentucky's Rider ESM tariff, as described in this order, is approved for service rendered on and after the date of this order.

36. The Rider ESM reporting formats described in this order shall be used for the monthly environmental surcharge filings.

37. Within 20 days of the date of this Order, Duke Kentucky shall file with the Commission, using the Commission's electronic Tariff Filing System, new tariff sheets setting forth the rates, charges, and modifications approved or as required herein and reflecting their effective date and that they were authorized by this Order.

38. This case is closed and removed from the Commission's docket.

By the Commission

ENTERED

APR 13 2018

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Gwen R. Pinson

Executive Director

Case No. 2017-00321

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00321 DATED APR 13 2018

Adjustments	Amounts
Adjust Revenue from Base Period to Test Period	($5,133,384)
Adjust Fuel & Purchased Power	($1,284,619)
Adjust Other Production Expense	$12,650,083
Adjust Transmission Expense	$919,747
Adjust Regional Market Expense	$79,447
Adjust Distribution Expense	($43,555)
Adjust Customer Account Expense	$671,968
Adjust Customer Service and Information Expense	$183,121
Adjust Sales Expense	($151,501)
Adjust A &G Expense	($1,497,124)
Adjust Other Operating Expense	$2,680,605
Adjust Other Tax Expense	$2,105,609
Amortization of Deferred Asset	$463,931
Rate Case Expense	$120,538
Eliminate ESM Expense from Base Rates	($12,398,573)
Interest Expense Adjustment (Net)	($107,901)
Eliminate Non-Native Revenue and Expense (Net)	($1,823,636)
Amortization of Deferred Depreciation	$490,618
DSM Elimination (Net)	($225,378)
Eliminate Miscellaneous Expense	($539,892)
Eliminate Unbilled Revenue	$3,258,473
Eliminate Merger CTA Expense	($237,780)
Annualize PJM Charges and Credits	$774,947
Annualize East Bend Maintenance	$4,777,143
Amortization of Deferred Expenses	$6,247,623
Adjust Uncollectible Expense	($1,418,703)
Annualize RTEP Expense	$1,979,833
Adjust Revenue to Reconcile Schedule M with Budget	$4,801,375

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00321 DATED APR 1 3 2018

DUKE FILED

	Duke Energy KY Electric Capitalization	Adjustment	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment
Stort Term Debt	$ 73,522,733		10.428%	3.083%	0.321%	0.321%	$ 2,266,706
Long Term Debt	$ 286,807,753		40.679%	4.243%	1.726%	1.726%	$ 12,169,253
Common Equity	$ 344,720,654		48.893%	10.30%	5.036%	8.208%	$ 57,868,571
	$ 705,051,140		100%		7.083%	10.26%	$ 72,304,530

TAX IMPACT

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 73,522,733		$ 73,522,733	10.428%	3.083%	0.321%	0.321%	$ 2,266,706	$ -
Long Term Debt	$ 286,807,753		$ 286,807,753	40.679%	4.243%	1.726%	1.726%	$ 12,169,253	$ -
Common Equity	$ 344,720,654		$ 344,720,654	48.893%	10.300%	5.036%	6.753%	$ 47,613,375	$ (10,255,196)
	$ 705,051,140		$ 705,051,140	100%		7.083%	8.800%	$ 62,049,334	$ (10,255,196)
				100.000%					

ST DEBT IMPACT

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 73,522,733	$ (5,125,578)	$ 68,397,155	9.772%	3.083%	0.301%	0.301%	$ 2,108,684	$ (158,022)
Long Term Debt	$ 286,807,753		$ 286,807,753	40.977%	4.243%	1.739%	1.739%	$ 12,169,253	$ -
Common Equity	$ 344,720,654		$ 344,720,654	49.251%	10.300%	5.073%	6.803%	$ 47,613,375	$ -
	$ 705,051,140	$ (5,125,578)	$ 699,925,562	100%		7.113%	8.843%	$ 61,891,312	$ (158,022)
				100.000%					

EAST BEND O&M REG ASSET

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremental revenue requirement
Stort Term Debt	$ 68,397,155	$ (3,570,734)	$ 64,826,421	9.772%	3.083%	0.301%	0.301%	$ 1,998,599	$ (110,086)
Long Term Debt	$ 286,807,753	$ (14,973,186)	$ 271,834,567	40.977%	4.243%	1.739%	1.739%	$ 11,533,941	$ (635,312)
Common Equity	$ 344,720,654	$ (17,996,544)	$ 326,724,110	49.251%	10.300%	5.073%	6.803%	$ 45,127,663	$ (2,485,712)
	$ 699,925,562	$ (36,540,465)	$ 663,385,097	100%		7.113%	8.843%	$ 58,660,202	$ (3,231,110)

East End Coal Ash ARO

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 64,826,421	$ (1,808,733)	$ 63,017,687	9.772%	3.083%	0.301%	0.301%	$ 1,942,835	$ (55,763)
Long Term Debt	$ 271,834,567	$ (7,584,575)	$ 264,249,992	40.977%	4.243%	1.739%	1.739%	$ 11,212,127	$ (321,814)
Common Equity	$ 326,724,110	$ (9,116,038)	$ 317,608,072	49.251%	10.300%	5.073%	6.803%	$ 43,868,541	$ (1,259,122)
	$ 663,385,097	$ (18,509,346)	$ 644,875,751	100%		7.113%	8.843%	$ 57,023,504	$ (1,636,699)

Carbon Management Reg Asset

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 63,017,687	$ 19,544	$ 63,037,231	9.772%	3.083%	0.301%	0.301%	$ 1,943,438	$ 603
Long Term Debt	$ 264,249,992	$ 81,954	$ 264,331,946	40.977%	4.243%	1.739%	1.739%	$ 11,215,604	$ 3,477
Common Equity	$ 317,608,072	$ 98,502	$ 317,706,574	49.251%	10.300%	5.073%	6.803%	$ 43,882,147	$ 13,605
	$ 644,875,751	$ 200,000	$ 645,075,751	100%		7.113%	8.843%	$ 57,041,189	$ 17,685

ASL Methodology

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 63,037,231	$ 267,098	$ 63,304,329	9.772%	3.083%	0.301%	0.301%	$ 1,951,672	$ 8,235
Long Term Debt	$ 264,331,946	$ 1,120,024	$ 265,451,970	40.977%	4.243%	1.739%	1.739%	$ 11,263,127	$ 47,523
Common Equity	$ 317,706,574	$ 1,346,177	$ 319,052,751	49.251%	10.300%	5.073%	6.803%	$ 44,068,083	$ 185,936
	$ 645,075,751	$ 2,733,299	$ 647,809,050	100%		7.113%	8.843%	$ 57,282,882	$ 241,693

ROE

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 63,304,329		$ 63,304,329	9.772%	3.083%	0.301%	0.30%	$ 1,951,672	$ -
Long Term Debt	$ 265,451,970		$ 265,451,970	40.977%	4.243%	1.739%	1.74%	$ 11,263,127	$ -
Common Equity	$ 319,052,751		$ 319,052,751	49.251%	9.725%	4.790%	6.42%	$ 41,607,971	$ (2,460,111)
	$ 647,809,050		$ 647,809,050	100%		6.830%	8.46%	$ 54,822,771	$ (2,460,111)

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APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00321 DATED APR 13 2018

The following rates and charges are prescribed for the customers in the area served by Duke Energy Kentucky, Inc. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under the authority of the Commission prior to the effective date of this Order.

RATE RS
RESIDENTIAL SERVICE

Customer Charge per month	$	11.00
Energy Charge per kWh:		
All kWh per month	$	0.071520

RATE DS
SERVICE AT SECONDARY DISTRIBUTION VOLTAGE

Customer Charge per month:		
Single Phase Service	$	17.14
Three Phase Service	$	34.28
Demand Charge per kW:		
First 15 kW	$	.00
Additional kW	$	8.25
Energy Charge per kWh:		
First 6,000 kWh	$	0.080075
Next 300 kWh/kW	$	0.049155
Additional kWh	$	0.040254

The maximum monthly rate, excluding the customer charge, and all applicable riders, shall now exceed $0.236547 per kWh

For customers receiving service under the provisions of former Rate C, Optional Rate for Churches, as of June 25, 1981, the maximum monthly rate per kWh shall not exceed $0.145219 per kWh

RATE DT
TIME-OF-DAY RATE FOR SERVICE AT DISTRIBUTION VOLTAGE

Customer Charge per month:	
Single Phase	$ 63.50
Three Phase	$ 127.00
Primary Voltage Service	$ 138.00
Demand Charge per kW:	
Summer on-peak	$ 13.78
Winter on-peak	$ 13.04
Off-peak	$ 1.24
Energy Charge per kWh:	
Summer on-peak	$ 0.043370
Winter on-peak	$ 0.041403
Off-peak	$ 0.035516
Primary Service Discount:	
Metering of on-peak billing demand per kW:	
First 1,000 kW	$ (0.70)
Additional kW	$ (0.54)

RATE EH
OPTIONAL RATE FOR ELECTRIC SPACE HEATING

Winter Period	
Customer Charge per month:	
Single Phase Service	$ 17.14
Three Phase Service	$ 34.28
Primary Voltage Service	$ 117.00
Energy Charge per kWh:	
All kWh per month	$ 0.062202

RATE SP
SEASONAL SPORTS SERVICE

Customer Charge per month:	$ 17.14
Energy Charge per kWh:	
All kWh per month	$ 0.096130

RATE GS-FL
OPTIONAL UNMETERED GENERAL SERVICE RATE FOR SMALL FIXED LOADS

Base Rate per kWh:		
Load range of 540 to 720 hours per month	$	0.082708
Loads less than 540 hours per month	$	0.095240
Minimum per Fixed Load Location per month:	$	2.98

RATE DP
SERVICE AT PRIMARY DISTRIBUTION VOLTAGE

Customer Charge per month:		
Primary Voltage Service (12.5 or 34.5 kV)	$	117.00
Demand Charge per kW:		
All kW	$	7.92
Energy Charge per kWh:		
First 300 kWh/kW	$	0.051092
Additional kWh	$	0.043219

The maximum monthly rate, excluding the customer charge, electric fuel component charges, and DSM charge shall not exceed $0.241312 per kWh.

RATE TT
TIME-OF-DAY RATE FOR SERVICE AT TRANSMISSION VOLTAGE

Customer Charge per month:	$	500.00
Demand Charge per kW:		
Summer on-peak	$	8.07
Winter on-peak	$	6.62
Off-peak	$	1.22
Energy Charge per kWh:		
Summer on-peak	$	0.048997
Winter on-peak	$	0.046775
Off-peak	$	0.040124

RIDER GSS
GENERATION SUPPORT SERVICE

Administrative Charge:	$	50.00
Monthly Transmission and Distribution Reservation Charge:		
Rate DS – Secondary Distribution Service	$	0.047126
Rate DT – Distribution Service	$	0.058517
Rate DP – Primary Distribution Service	$	0.059794
Rate TT – Transmission Service	$	0.026391

RATE SL
STREET LIGHTING SERVICE

Base Rate per Unit per Month:

OVERHEAD DISTRIBUTION AREA

Standard Fixture (Cobra Head)	
Mercury Vapor:	
7,000 Lumen	$ 7.27
7,000 Lumen (Open Refractor)	$ 6.07
10,000 Lumen	$ 8.39
21,000 Lumen	$ 11.23
Metal Halide:	
14,000 Lumen	$ 7.27
20,500 Lumen	$ 8.39
36,000 Lumen	$ 11.23
Sodium Vapor:	
9,500 Lumen	$ 8.04
9,500 Lumen (Open Refractor)	$ 6.04
16,000 Lumen	$ 8.77
22,000 Lumen	$ 11.37
27,500 Lumen	$ 11.37
50,000 Lumen	$ 15.28
Decorative Fixtures	
Sodium Vapor:	
9,500 Lumen (Rectilinear)	$ 10.00
22,000 Lumen (Rectilinear)	$ 12.36
50,000 Lumen (Rectilinear)	$ 16.35
50,000 Lumen (Setback)	$ 24.31

Spans of Secondary Wiring: For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $ 0.53

UNDERGROUND DISTRIBUTION AREA

Standard Fixture (Cobra Head)	
Mercury Vapor:	
7,000 Lumen	$ 7.40
7,000 Lumen (Open Refractor)	$ 6.07
10,000 Lumen	$ 8.54
21,000 Lumen	$ 11.50

Metal Halide:		
14,000 Lumen	$	7.40
20,500 Lumen	$	8.54
36,000 Lumen	$	11.50
Sodium Vapor:		
9,500 Lumen	$	8.04
9,500 Lumen (Open Refractor)	$	6.12
16,000 Lumen	$	8.74
22,000 Lumen	$	11.37
27,500 Lumen	$	11.37
50,000 Lumen	$	15.28
Decorative Fixture:		
Mercury Vapor:		
7,000 Lumen (Town & Country)	$	7.65
7,000 Lumen (Holophane)	$	9.61
7,000 Lumen (Gas Replica)	$	21.96
7,000 Lumen (Granville)	$	7.73
7,000 Lumen (Aspen)	$	13.91
Metal Halide:		
14,000 Lumen (Traditionaire)	$	7.64
14,000 Lumen (Granville Acorn)	$	13.91
14,000/14,500 Lumen (Gas Replica)[214]	$	22.04
Sodium Vapor:		
9,500 Lumen (Town & Country)	$	11.17
9,500 Lumen (Holophane)	$	12.10
9,500 Lumen (Rectilinear)	$	9.02
9,500 Lumen (Gas Replica)	$	22.75
9,500 Lumen (Aspen)	$	14.09
9,500 Lumen (Traditionaire)	$	11.17
9,500 Lumen (Granville Acorn)	$	14.09
22,000 Lumen (Rectilinear)	$	12.42
50,000 Lumen (Rectilinear)	$	16.41
50,000 Lumen (Setback)	$	24.31

[214] Duke Kentucky's billing analysis lists both a 14,000 and 14,500 Lumen Gas Replica light at the same rate.

POLE CHARGES

Pole Description:

Wood:

17 Foot (Wood Laminated) (a)	$	4.50
30 Foot	$	4.44
35 Foot	$	4.50
40 Foot	$	5.39

Aluminum:

12 Foot (Decorative)	$	12.23
28 Foot	$	7.09
28 Foot (Heavy Duty)	$	7.16
30 Foot (Anchor Base)	$	14.16

Fiberglass:

17 Foot	$	4.50
12 Foot (Decorative)	$	13.15
30 Foot (Bronze)	$	8.56
35 Foot (Bronze)	$	8.79

Steel:

27 Foot (11 gauge)	$	11.56
27 Foot (3 gauge)	$	17.43

Spans of Secondary Wiring: For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $ 0.77

RATE TL
TRAFFIC LIGHTING SERVICE

Base Rate per kWh:		
Energy only	$	0.038903
Energy from separately metered source w/maintenance	$	0.021543
Energy w/maintenance	$	0.060446

RATE UOLS
UNMETERED OUTDOOR LIGHTING ELECTRIC SERVICE

Base Rate per kWh:		
All kWh per month	$	0.038305

RATE LED
LED OUTDOOR LIGHTING ELECTRIC SERVICE

Base Rate per kWh:

All kWh per month $ 0.038305

Monthly Maintenance and Fixture Charge Per Unit Per Month

Fixtures:

	Fixture	Maintenance
50W Standard LED-Black	$ 4.96	$ 4.24
70W Standard LED-Black	$ 4.95	$ 4.24
110W Standard LED-Black	$ 5.62	$ 4.24
150W Standard LED-Black	$ 7.44	$ 4.24
220W Standard LED-Black	$ 8.43	$ 5.17
280 W Standard LED-Black	$ 10.38	$ 5.17
50W Deluxe Acorn LED-Black	$ 14.47	$ 4.24
50W Acorn LED-Black	$ 13.04	$ 4.24
50W Mini Bell LED-Black	$ 12.30	$ 4.24
70W Bell LED-Black	$ 15.66	$ 4.24
50W Traditional LED-Black	$ 9.45	$ 4.24
50W Open Traditional LED-Black	$ 9.45	$ 4.24
50W Enterprise LED-Black	$ 12.70	$ 4.24
70W LED Open Deluxe Acorn	$ 14.11	$ 4.24
150W LED Teardrop	$ 18.95	$ 4.24
50W LED Teardrop Pedestrian	$ 15.37	$ 4.24
220W LED Shoebox	$ 13.13	$ 5.17
LED 50W 4521 Lumens Standard LED Black Type III 4000K	$ 4.96	$ 4.24
LED 70W 6261 Lumens Standard LED Black Type III 4000K	$ 4.95	$ 4.24
LED 110W 9336 Lumens Standard LED Black Type III 4000K	$ 5.62	$ 4.24
LED 150W 12642 Lumens Standard LED Black Type III 4000K	$ 7.44	$ 4.24
LED 150W 13156 Lumens Standard LED Type IV Black 4000K	$ 7.44	$ 4.24
LED 220W 18642 Lumens Standard LED Black Type III 4000K	$ 8.43	$ 5.17
LED 280W 24191 Lumens Standard LED Black Type III 4000K	$ 10.38	$ 5.17
LED 50W Deluxe Acorn Black Type III 4000K	$ 14.47	$ 4.24
LED 70W Open Deluxe Acorn Black Type III 4000K	$ 14.11	$ 4.24
LED 50W Acorn Black Type III 4000K	$ 13.04	$ 4.24
LED 50W Mini Bell LED Black Type III		

4000K Midwest	$ 12.30	$ 4.24
LED 70W 5508 Lumens Sanibell Black Type III 4000K	$ 15.66	$ 4.24
LED 50W Traditional Black Type III 4000K	$ 9.45	$ 4.24
LED 50W Open Traditional Black Type III 4000K	$ 9.45	$ 4.24
LED 50W Enterprise Black Type III 4000K	$ 12.70	$ 4.24
LED 150W Large Teardrop Black Type III 4000K	$ 18.95	$ 4.24
LED 50W Teardrop Pedestrian Black Type III 4000K	$ 15.37	$ 4.24
LED 220W Shoebox Black Type IV 4000K	$ 13.13	$ 5.17
150W Sanibel	$ 15.66	$ 4.24
420W LED Shoebox	$ 19.58	$ 5.17
50W Neighborhood	$ 4.04	$ 4.24
50W Neighborhood with Lens	$ 4.21	$ 4.24

Monthly Pole Charges Per Unit Per Month:

12' C-Post Top Anchor Base-Black	$ 9.39
25' C-Davit Bracket-Anchor Base-Black	$ 24.69
25' C-Boston Harbor Bracket-Anchor Base-Black	$ 24.96
12' E-AL – Anchor Base-Black	$ 9.38
35' AL-Side Mounted-Direct Buried Pole	$ 15.89
30' AL-Side Mounted-Anchor Base	$ 12.24
35' AL-Side Mounted-Anchor Base	$ 11.91
40' AL-Side Mounted-Anchor Base	$ 14.73
30' Class 7 Wood Pole	$ 5.82
35' Class 5 Wood Pole	$ 6.33
40' Class 4 Wood Pole	$ 9.53
45' Class 4 Wood Pole	$ 9.88
20' Galleria Anchor Based Pole	$ 8.40
30' Galleria Anchor Based Pole	$ 9.93
35' Galleria Anchor Based Pole	$ 28.56
MW-Light Pole-12' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 5.69
MW-Light Pole-Post Top-12' MH-Style A-Alum-Direct Buried-Top Tenon-Black	$ 4.87
Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 5.85
Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 5.07
Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 6.14

Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 9.41
Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 7.27
Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 10.49
Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 8.60
Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 11.67
Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 9.93
Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 12.61
MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$ 6.93
MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$ 9.39
MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$ 12.56
MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$ 24.69
MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 10.07
MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 24.96
MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$ 9.29
MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$ 9.38
MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Pri	$ 10.06
MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$ 8.40
MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$ 9.93
MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$ 28.56
MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$ 15.89
MW-15320-30FT Mounting Height Aluminum Anchor Base Pole-OLE	$ 12.24
MW-15320-35FT Mounting Height Aluminum Anchor Base Pole-OLE	$ 11.91
MW-15320-40FT Mounting Height Aluminum Anchor Base Pole-OLE	$ 14.73
MW-POLE-30-7	$ 5.82
MW-POLE-35-5	$ 6.33
MW-POLE-40-4	$ 9.53
MW-POLE-45-4	$ 9.88

RATE NSU
STREET LIGHTING SERVICE - NONSTANDARD UNITS

Rate per Unit per Month:

Company Owned

Boulevard Units Served Underground:

2,500 Lumen Incandescent - Series	$	9.42
2,500 Lumen Incandescent - Multiple	$	7.32

Holophane Decorative Served Underground:

10,000 Lumen Mercury Vapor on Fiberglass Pole	$	17.16

The cable span charge of $0.77 per each increment of 25 feet of secondary wiring shall be added to the rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street Lighting Served Overhead:

2,500 Lumen Incandescent	$	7.26
2,500 Lumen Mercury Vapor	$	6.87
21,000 Lumen Mercury Vapor	$	10.89

Customer Owned

Steel Boulevard Units Served Underground:

2,500 Lumen Incandescent - Series	$	5.56
2,500 Lumens Incandescent - Multiple	$	7.07

RATE SC
STREET LIGHTING SERVICE – CUSTOMER OWNED

Base Rate per Unit per Month:
Standard Fixture (Cobra Head):
Mercury Vapor:

7,000 Lumen	$	4.28
10,000 Lumen	$	5.45
21,000 Lumen	$	7.56

Metal Halide:

14,000 Lumen	$	4.28
20,500 Lumen	$	5.45
36,000 Lumen	$	7.56

Sodium Vapor:		
9,500 Lumen	$	5.15
16,000 Lumen	$	5.74
22,000 Lumen	$	6.31
27,500 Lumen	$	6.31
50,000 Lumen	$	8.54
Decorative Fixture:		
Mercury Vapor:		
7,000 Lumen (Holophane)	$	5.44
7,000 Lumen (Town & Country)	$	5.39
7,000 Lumen (Gas Replica)	$	5.44
7,000 Lumen (Aspen)	$	5.44
Metal Halide:		
14,000 Lumen (Traditionaire)	$	5.39
14,000 Lumen (Granville Acorn)	$	5.44
14,000 Lumen (Gas Replica)	$	5.44
Sodium Vapor:		
9,500 Lumen (Town & Country)	$	5.07
9,500 Lumen (Traditionaire)	$	5.07
9,500 Lumen (Granville Acorn)	$	5.29
9,500 Lumen (Rectilinear)	$	5.07
9,500 Lumen (Aspen)	$	5.29
9,500 Lumen (Holophane)	$	5.29
9,500 Lumen (Gas Replica)	$	5.29
22,000 Lumen (Rectilinear)	$	6.68
50,000 Lumen (Rectilinear)	$	8.84

Pole Description:

Wood:		
30 Foot	$	4.44
35 Foot	$	4.50
40 Foot	$	5.39

Customer Owned and Maintained Units per kWh	$	0.038305

RATE SE
STREET LIGHTING SERVICE – OVERHEAD EQUIVALENT

Base Rate per Unit per Month:

Decorative Fixtures:		
Mercury Vapor:		
7,000 Lumen (Town & Country)	$	7.45
7,000 Lumen (Holophane)	$	7.48

7,000 Lumen (Gas Replica)	$	7.48
7,000 Lumen (Aspen)	$	7.48
Metal Halide:		
14,000 Lumen (Traditionaire)	$	7.45
14,000 Lumen (Granville Acorn)	$	7.48
14,000 Lumen (Gas Replica)	$	7.48
Sodium Vapor:		
9,500 Lumen (Town & Country)	$	8.12
9,500 Lumen (Holophane)	$	8.23
9,500 Lumen (Rectilinear)	$	8.12
9,500 Lumen (Gas Replica)	$	8.22
9,500 Lumen (Aspen)	$	8.22
9,500 Lumen (Traditionaire)	$	8.12
9,500 Lumen (Granville Acorn)	$	8.22
22,000 Lumen (Rectilinear)	$	11.67
50,000 Lumen (Rectilinear)	$	15.44
50,000 Lumen (Setback)	$	15.44

RATE DPA
DISTRIBUTION POLE ATTACHMENTS

Annual rental per pole per foot:		
Two-User pole	$	5.92
Three-User pole	$	4.95

COGENERATION AND SMALL POWER PRODUCTION SALE AND PURCHASE TARIFF-100 kW OR LESS

Rates for Purchases from Qualifying Facilities

Energy Purchase Rate per kWh	$	0.027645
Capacity Purchase Rate per kW-month	$	3.61

COGENERATION AND SMALL POWER PRODUCTION SALE AND PURCHASE TARIFF-GREATER THAN 100 kW

Rates for Purchases from Qualifying Facilities

The Energy Purchase Rate for all kWh delivered shall be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour of the billing month.

Capacity Purchase Rate per kW-month	$	3.61

SCHEDULE RTP
REAL-TIME PRICING PROGRAM

Energy Delivery Charge (Credit) per kW per hour from CBL		
Secondary Service	$	0.009104
Primary Service	$	0.007850
Transmission Service	$	0.003576

NON-RECURRING CHARGES

Remote Reconnection	$	3.45
Reconnection – Non-remote (Electric Only)	$	75.00
Reconnection - Non-remote (Electric and Gas)	$	88.00
Reconnection at pole (Electric Only)	$	125.00
Reconnection at pole (Electric and Gas)	$	150.00
Collection Charge	$	50.00

RIDER LM
LOAD MANAGEMENT RIDER

When a customer elects the off-peak provision, the monthly customer charge of the applicable Rate DS or DP will be increased by an additional monthly charge of $5.00 for each installed time-of-use or interval data recorder meter.

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