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**	**)** **)** **)** **)** **)** **)** **)**	**Case No. 2018-00294**
In the Matter of: **ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES**	**)** **)** **)** **)** **)** **)** **)** **)**	**Case No. 2018-00295**

Direct Testimony and Exhibits of

James T. Selecky

On behalf of

United States Department of Defense
and all other Federal Executive Agencies

January 16, 2019

BRUBAKER & ASSOCIATES, INC.

Project 10675.1 & 10675.2

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<u>DIRECT TESTIMONY OF JAMES T. SELECKY</u>

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA"). The DoD/FEA takes service from Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") on several electric and gas rate schedules. Specifically, Fort Knox takes gas service from LG&E on the Substitute Gas Sales Service rate ("SGSS").

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony will address cost of service, revenue allocation and rate design. Regarding rate design, I will also address the proposed electric Time-of-Day Primary Service rates for the Companies and LG&E's SGSS. I will also address the Companies' proposed book depreciation rates for its production plants. My colleague, Christopher Walters, will be addressing the appropriate rate of return that the Kentucky Public Service Commission ("Commission") should utilize to determine the Companies' revenue requirement and revenue deficiency. The fact that I have not addressed an issue should not be construed as an endorsement of the Companies' positions.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations can be summarized as follows:

1. The Companies have presented electric cost of service studies that rely on the Loss of Load Probability ("LOLP") methodology to allocate fixed production costs.

2. The cost of service studies sponsored by the Companies also allocate fixed transmission costs using non-coincident peaks.

3. The Commission should use the coincident peak ("CP") methodology to allocate the fixed production and transmission costs.

4. The Residential rates are significantly below cost of service. The Residential rate increases proposed by the Companies do little to reduce the significant rate subsidies that the Residential classes are receiving from the other rate classes.

5. The Companies' proposed method of cost recovery for the Time-of-Day Primary Service rates ("TODP") for the Base, Intermediate and Peak demand charges should be adopted by the Commission. That is, the Base demand charges should collect fixed transmission and distribution costs and the Intermediate and Peak demand charges should recover fixed production costs.

6. The TODP contains a provision in the Determination of Maximum Load clause that addresses the setting of the demand period under certain circumstances for customers with on-site or distributed generation. This same provision should be included in LG&E's Retail Transmission Service rate ("RTS").

7. LG&E's proposed SGSS rate should contain a ratchet provision of 70% that will be applied to the previous 11-month highest day demand to establish a minimum billing demand.

8. The life spans of certain production plants should be extended by 3 years. This will reduce the depreciation expense of KU by $12.1 million and the depreciation expense of LG&E by $2.5 million.

III. <u>KU AND LG&E ELECTRIC COST OF SERVICE STUDIES</u>

Q DID EACH OF THE COMPANIES PREPARE AN ELECTRIC COST OF SERVICE STUDY?

A Yes. A separate electric cost of service study was prepared for KU and LG&E. The cost of service studies used the LOLP methodology to allocate fixed production costs. The cost of service studies are discussed in the direct testimony of the Companies' witness William Steven Seelye of The Prime Group, LLC. Also LG&E presented a gas cost of service study.

Q WHAT IS THE BASIC PURPOSE OF A COST OF SERVICE STUDY?

A After determining the utility's total cost to serve or revenue requirement, a cost of service study is used to allocate the revenue requirement or cost responsibility among the customer/rate classes. A cost of service study compares the cost that each customer class imposes on the system to the revenues each class contributes. For example, when a customer class produces the same rate of return as the total system average rate of return, it is paying revenue to the utility just sufficient to cover the costs incurred in serving that class. If a class produces a below-average rate of return, it may be concluded that the revenues provided by the class are insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it but, in addition, it is paying part of the cost attributable to other classes who produce a below system average rate of return. In conclusion, the class cost of service study ("COSS") is important, because it shows the cost to serve each rate class reflecting costcausation principles, as well as the rate of return from each class under both current and proposed rates.

Q DO YOU SUPPORT THAT PREMISE?

A Yes. Cost-based rates are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration may also be appropriate for consideration when determining the spread of the revenue requirement among classes, the fundamental starting point and guideline should be the actual cost of serving each customer class. Ideally, all rate classes should eventually be at cost of service.

Q WHAT ARE THE MAJOR STEPS IN A COSS?

A The first step in a COSS is known as functionalization. This simply refers to the process by which the utility's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission distribution and customer related. Of course, each broad function may have several subcategories that provide for a more precise determination of cost of service.

The second major step is known as classification. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related and customer-related costs.

Demand- or capacity-related costs are those costs that vary with the amount of demand placed on the system. A traditional example of capacity-related costs is the investment associated with generating stations and transmission and distribution lines and stations. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours ("kWh") generated.

Energy-related costs are those costs that vary in proportion to the number of kWh sold. Thus, the fuel expense is almost directly proportional to the amount of kWh generated by the utility system.

Customer-related costs are those costs that vary in proportion with the number of customers served. Primary examples of customer-related costs are investments in meters and service lines, and such accounting functions as meter reading, bill preparation and revenue accounting.

The final step in the COSS is the allocation of each category of costs to the various customer classes. Demand-related costs are allocated on some basis which gives recognition to each class's responsibility for the utility's need to build infrastructure to serve demands imposed on the system. Energy-related costs are generally allocated on the basis of energy use by each customer class. Customer-related costs are generally allocated based upon the number of customers in each class, weighted to account for the complexity of serving the different classes of customers.

Q WHAT IS THE IMPORTANCE OF BASING RATES ON COST OF SERVICE?

A When rates are based on costs, each customer (to the extent practical), pays what it costs the utility to serve the customer, no more, no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues, thus subsidizing service provided to other customers. This process tends to convey wrong price signals to customers.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the demand costs, energy costs, and customer costs are properly reflected in the demand, energy, and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent fixed cost that the utility incurs to meet that demand and through the energy charge they should pay the cost of providing that energy.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the demand and customer components of the rate will result in a disproportionate share of revenues being collected from high energy consuming or high load factor customers and send erroneous price signals to all customers.

Q HOW ARE FIXED PRODUCTION COSTS ALLOCATED IN THE COMPANIES' ELECTRIC COST OF SERVICE STUDIES?

A The cost of service studies use the LOLP methodology to allocate fixed production costs.

Q COULD YOU BRIEFLY DISCUSS THE LOLP METHODOLOGY FOR ALLOCATING FIXED PRODUCTION COSTS?

A The LOLP methodology represents the probability that the Companies' system demand will exceed its generation during any given hour. An LOLP is calculated for each hour. The LOLP takes into account the magnitude of the hourly load, installed generation capacity, forced outage rates, maintenance schedules and other generating operating statistics. For many of the hours when the system demand is low the LOLP is zero. LG&E witness Mr. Seelye discussed the LOLP methodology in his prefiled direct testimony.

Q ARE YOU RECOMMENDING THE COMMISSION USE THE LOLP METHODOLOGY TO ALLOCATE THE PRODUCTION FIXED COSTS?

A No, I recommend that the Commission use the coincident peak ("CP") methodology to allocate the fixed production costs.

Q ARE YOU PROPOSING ANY OTHER CHANGES TO THE COMPANIES' COST OF SERVICE STUDIES?

A Yes. The Companies allocated the fixed transmission costs on non-coincident peaks ("NCP"). The fixed transmission costs should be allocated on coincident peaks.

IV. RESULTS OF THE COMPANIES' ELECTRIC COST OF SERVICE STUDIES AND REVENUE ALLOCATION

Q BEFORE YOU DISCUSS YOUR PROPOSED CHANGES TO THE COMPANIES' ELECTRIC COST OF SERVICE STUDIES, WHAT DO THE RESULTS OF THE ELECTRIC CLASS COST OF SERVICE STUDIES PREPARED BY THE COMPANIES SHOW?

A The results of the electric cost of service study for KU is shown on Exhibit JTS-1 and the results of the electric cost of service study performed for LG&E is shown on Exhibit JTS-2. These exhibits show the rate of return by the various rate classes, the index of return and the subsidy that each rate class is receiving or providing under current rates and the impact on the cost of service of the Companies' proposed allocation of the increase. The index of return compares the rate class's rate of return with the total system return.

The results of the KU cost of service study show that the Residential rate classes are providing a rate of return of only 3.03% at present rates. The total system rate of return at present rates is 5.58%. The only other major rate class (revenues in excess of $50 million) that is providing a rate of return below the system average is the TODP. The index of return for the Residential rate classes is 54% of the total system return.

At present rates, the Residential rate classes are currently receiving a subsidy of approximately $65.3 million from other rate classes. That is, the Residential rates would have to be increased by $65.3 million or approximately 10.5% to produce a system average rate of return of 5.58%. . This increase does not include any of the increase in electric rates that KU is seeking in this proceeding.

The results for the LG&E electric cost of service study are similar. For LG&E, the Residential rate classes' rate of return at present rates is 2.69% and the system average rate of return at present rates is 6.73%. For LG&E, the Residential rate classes are receiving a revenue subsidy of $73.3 million from other rate classes. For LG&E, the Residential rate classes are the only major rate classes that are receiving a subsidy. That is, for all other major rate classes, the rate of return at present rates exceeds the total system average of 6.73%. The Residential rate classes will need an increase of approximately 16%, or $73.3 million, to bring their rates to cost of service.

Q ARE THE COMPANIES PROPOSING TO ALLOCATE THE INCREASE IN A MANNER THAT REFLECTS THE RESULTS OF THE COST OF SERVICE STUDIES?

A Yes, but the proposed allocation of the increase does not reduce the rate subsidies the Residential rate classes are receiving. For both KU and LG&E, the proposed increases for the Residential classes are larger than the increases proposed for the other rate classes.

Under the Companies' proposal the affected rate classes are placed in four Tiers and each Tier receives a different percentage of increase. This procedure is used for

KU and LG&E to allocate the increase. Tier 1, which includes the Residential rate classes, receives an increase of 1 percentage point above the overall increase. This increase is above the system average because the cost of service studies showed that the Residential rate classes are receiving significant rate subsidies.

The Tier 4 rate classes, which are Lighting Energy and Traffic Energy Services, receive no increase because the cost of service studies indicate very high rates of return for these two rate classes.

For the Tier 3 rate classes, the Companies are proposing an increase of 1 percentage point below the overall increase percentage. These rate classes have higher rates of return than the Residential rate classes and are comprised of the four large customer rate schedules.

The other rate classes which are included in Tier 2 receive a rate increase less than the system average because the Tier 2 rates of return are above the system average rate of return.

The proposed allocation of the Companies' increases and the reasons supporting it are contained in Mr. Seelye's testimony on pages 8-9.

Q DOES THE PROPOSED INCREASE FOR THE RESIDENTIAL CUSTOMERS PROVIDE SUFFICIENT MOVEMENT TOWARD COST OF SERVICE?

A No. The results of the KU cost of service study show that the Residential rate classes will only be earning a rate of return of 4.99% after the proposed increase. This is well below the system average rate of return of 7.66% shown on Exhibit WSS-28, page 27 of 36. After KU's proposed allocation of the increase the Residential classes will still be receiving a subsidy of approximately $68.5 million. That is, Residential rates will still be approximately 10% below cost of service. The rate classes' rates of returns, index of returns and subsidies after KU's proposed increase are shown on Exhibit JTS-1. This data reflects the results of KU's cost of service study and proposed allocation of the increase.

For LG&E, the situation is similar. In that instance, the Residential rate classes' rate of return will be 3.71% after the proposed increase. This is significantly below the system average rate of return of 7.75% shown on Exhibit WSS-29, page 25 of 38. After the proposed increase the Residential classes will still be receiving a subsidy of $73.4 million and their rates would have to be increased by 15% to bring their rates to cost of service. The rate classes' rates of return, index of returns and subsidies after LG&E's proposed increase are shown on Exhibit JTS-2. This data reflects the results of LG&E's cost of service study and proposed allocation of the increase.

Q WHAT IS YOUR RECOMMENDATION FOR ALLOCATING THE REVENUE INCREASE ASSUMING THE COMMISSION APPROVES THE COMPANIES' COST OF SERVICE STUDIES AND REVENUE DEFICIENCY?

A If the Commission approves KU's cost of service study and proposed revenue deficiency, the Residential increase should be increased by 2 percentage points over the system average and the additional revenues generated by this increase should be used to reduce the Tiers 2 and 3 proposed increases. The decrease could be spread proportionately to the increases that the Companies are proposing for Tiers 2 and 3. This alternative spread of this increase for KU is shown on Exhibit JTS-3.

A similar procedure should be followed for LG&E. However, in that case the Residential increase should be 3 percentage points over the system average. Three percentage points is used for the LG&E increase because the total percentage proposed increase for LG&E is smaller and the LG&E Residential classes are farther away from cost of service. This alternative spread of this increase for LG&E is shown on Exhibit JTS-4.

Q IF THE COMPANIES ARE ALLOCATED AN INCREASE THAT IS LESS THAN THE REQUESTED AMOUNT HOW SHOULD THE COMMISSION ALLOCATE THE INCREASE?

A. The differences in the revenue deficiencies between the amount approved by the Commission and the amount the Companies requested could be used to proportionally reduce the revenue increase amounts for Tiers 1 through 3 shown in column 4 of Exhibits JTS-3 and JTS-4.

V. DOD/FEA REVISIONS TO THE COMPANIES' COST OF SERVICE STUDIES

Q DO YOU HAVE ANY PROPOSED REVISIONS TO THE ELECTRIC COST OF SERVICE STUDIES THAT THE COMPANIES HAVE PROVIDED IN THIS CASE?

A Yes. I am recommending that the Commission not utilize the LOLP methodology for allocating fixed production costs. The Commission should utilize the coincident peak methodology for allocating the fixed production costs.

For the transmission costs, the Companies allocated the costs to rate classes utilizing non-coincident peaks. I recommend that the Commission utilize coincident peaks to allocate the fixed transmission costs to various rate classes.

Q HAVE ANY OTHER REGULATORY JURISDICTIONS ADOPTED THE LOLP COST OF SERVICE METHOD PROPOSED BY THE COMPANIES IN THIS CASE?

A I am not aware of any regulatory commissions that use the LOLP methodology to allocate fixed production costs. Also, in response to the Kentucky Industrial Utility Customers, Inc., Question No. 15, the Companies' cost of service witness Mr. William Seelye stated that he is unaware of any regulatory commissions that have adopted the LOLP cost of service method used in this case. Therefore even though utility commissions and regulatory staffs have been aware of the LOLP methodology for over 25 years it is not used by any commission for cost of service purposes. The National Association of Regulatory Utility Commissioners ("NARUC") discusses the LOLP methodology in its Electric Utility Cost Allocation Manual published January 1992.

Q WHY DO YOU ENDORSE THE COINCIDENT PEAK METHOD FOR ALLOCATING FIXED PRODUCTION AND TRANSMISSION COSTS BASED ON COINCIDENT PEAK?

A The coincident peak methodology allocates costs to the rate classes based on each rate class's contribution to the annual peak demand. Each customer's or rate class allocation factor is developed from the ratio of their respective demand to the total system demand during the hour of the utility's annual peak. Utilizing the coincident peak factor recognizes the necessity of having generation and transmission resources in place to meet annual peak demands. The production and transmission systems are designed and built to meet the maximum coincident peak demands. It is these peak demands that dictate the utility's transmissions and production capacity needs. All rate classes should be allocated those costs based on the relevant coincident peak demands.

Q DO YOU HAVE ANY OTHER CONCERNS ABOUT USING THE LOLP METHOD IN COST OF SERVICE STUDIES?

A Yes. The LOLP method lacks transparency in that it is nearly impossible for intervenors in a rate proceeding to develop their own LOLP factors for purposes of allocating costs. Also, it is my understanding that the LOLP method was not specifically developed for performing class cost of service studies. It was used in the generation planning process to develop generation reserve criteria.

Also, it should be noted that the Electric Utility Cost Allocation manual published by NARUC addresses the LOLP production cost method. In the paragraph that discusses the LOLP production cost method the manual states the following regarding this method:

> "This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort." (Page 62)

The Commission should rely on an allocation methodology that is more transparent for developing fixed production cost allocation factors for use in class cost of service studies.

Q YOU ALSO INDICATED THAT YOU DO NOT SUPPORT THE USE OF THE NON-COINCIDENT PEAKS FOR ALLOCATING TRANSMISSION COSTS. WOULD YOU PLEASE EXPLAIN WHY?

A The transmission system is not designed to meet each customer's class's maximum load. The transmission system is designed to meet the coincident peak demand of the various rate classes that a utility is serving. The Companies used non-coincident peaks based on the maximum class demands for transmission, primary and secondary voltage customers to allocate the fixed transmission costs. Utilities in general plan their transmission system to meet coincident peak demands. Finally, the CP methodology for allocating transmission costs is widely used throughout the utility industry.

Q HOW MANY MONTHLY COINCIDENT PEAK DEMANDS DID YOU UTILIZE TO DEVELOP YOUR FIXED PRODUCTION AND TRANSMISSION DEMAND ALLOCATOR?

A I use 6 CPs to allocate the production and transmission fixed costs to the various rate classes. The 6 CPs consist of four summer months (June through September) and two winter months (January and February). For each of those months, the highest monthly peak was used to develop the rate class allocators for the fixed production and transmission costs.

Q WHY IS THE 6 CP METHODOLOGY APPROPRIATE FOR ALLOCATING THE FIXED PRODUCTION AND TRANSMISSION COSTS IN THE CLASS COST OF SERVICE STUDIES?

A The Companies plan their generation needs for both KU and LG&E collectively. The Companies' coincident peak demand can occur in four summer months or in two winter months. Therefore, it is appropriate to use the peak demand in those months to allocate fixed production and transmission costs.

Exhibit JTS-5 shows the Companies' electric monthly maximum coincident peak demands in each month of the year for the five-year period from 2013 through 2017. This data was provided in response to Kentucky School Boards Association's First Request Question No. 5. To determine the critical months when the demand was the highest, I calculated the average of the peak demands incurred during each month for the period 2013 through 2017. This is shown on Exhibit JTS-5 as the Average of 2013-2017. Then the highest average monthly peak demand was compared with the average peak demand for each month. The result of this analysis indicated that during the winter months of January and February and summer months of June through September the peak demands were the highest. For example, the highest average peak demand occurred in July. However, in the month of January, the average peak demand was 99% of the July peak demand. For purposes of developing my allocators, I determined that it was appropriate to utilize a 6 CP allocator utilizing two winter months and four summer months. With the exception of February the average demands in those months exceeded 95% of the July peak. The average February demand was 94% of the July peak.

Q HAVE YOU PERFORMED COST OF SERVICE STUDIES FOR KU AND LG&E THAT UTILIZE THE 6 CP METHOD FOR ALLOCATING FIXED PRODUCTION AND TRANSMISSION COSTS?

A Yes. The results of those cost of service studies are shown on Exhibit JTS-6 for KU and Exhibit JTS-7 for LG&E. Those exhibits show the rate classes' rates of return at present rates, the index of return for each rate class and the rate subsidies at present rates for each rate class.

The results of the KU cost of service study indicate that the Residential rate classes are still receiving a significant subsidy from the other rate classes. As shown on Exhibit JTS-6, the only other major KU rate class that is receiving a subsidy is the TODP. The results of the cost of service study shows that at present rates, the Residential classes are receiving a subsidy of approximately $85 million from the other rate classes. The summarized cost of service study for each KU rate class using the 6 CP methodology to allocate fixed production and transmission cost is shown on Exhibit JTS-8.

For the results of the LG&E cost of service study shown on Exhibit JTS-7, the Residential classes' rate of return at present rates is 2.82%, which is below the system average rate of return of 6.73%. In this instance, the Residential classes are receiving a revenue subsidy of approximately $70 million. For LG&E, no other major rate class is receiving a rate subsidy. The summarized cost of service study for each LG&E rate class using the 6 CP methodology to allocate fixed production and transmission cost is shown on Exhibit JTS-9.

Q DO THE RESULTS OF THE COST OF SERVICE STUDIES UTILIZING THE 6 CP ALLOCATION METHODOLOGY CHANGE ANY OF YOUR RECOMMENDATIONS RELATING TO ALLOCATION OF ANY INCREASE IN THIS CASE?

A No, although there are differences between the cost of service studies promoted by the Companies and the cost of service studies utilizing the 6 CP allocation method, the results are similar in that the Residential rate classes are receiving a significant subsidy. Therefore, the Companies' proposed revenue allocation as modified earlier in my testimony is appropriate for the allocation of any increase.

VI. <u>TIME-OF-DAY PRIMARY SERVICE ("TODP")</u>

Q DO YOU HAVE ANY COMMENTS REGARDING THE PROPOSED TODP RATE DESIGN FOR THE COMPANIES?

A The Companies' proposed method of cost recovery for TODP from the Base, Intermediate and Peak demand charges should be adopted by the Commission. Just so it is clear, I am speaking of the methodology and I am not recommending that the Commission adopt the Companies' proposed rates for the Base, Intermediate and Peak period demand charges.

The Companies' proposed rate design for TODP recovers fixed transmission and distribution demand-related costs in the Base demand period. The Intermediate and Peak demand period charges are designed to recover fixed production demand-related costs.

VII. LG&E'S RETAIL TRANSMISSION SERVICE RATE ("RTS")

Q ARE YOU PROPOSING ANY CHANGES TO LG&E'S RTS?

A Yes. I am proposing an addition to LG&E's RTS Determination of Maximum Load provision. I am proposing that the wording contained in the TODP's Determination of Maximum Load provision that addresses the operating of on-site generation be added to the RTS.

Q WHAT IS THE LANGUAGE THAT YOU ARE ADDING TO THE RTS RATE?

A The language I am adding to the RTS rate is as follows:

> Customers who own and operate on-site generation of one (1) MW or larger that is not for emergency backup will be provided a 60 minute exemption for measuring load for billing purposes following a Company-system fault, but not a Company energy spike, a fault on a Customer's system, or other causes or events that result in the Customer's generation coming offline. The 60 minute exemption will begin after Company's SCADA system indicates service has been restored.

This is the same language that is contained in LG&E's TODP.

Q WHY ARE YOU PROPOSING THIS CHANGE?

A I am proposing this change because the DoD/FEA's facility at Fort Knox is investigating the economic viability of taking service at a transmission level voltage. This would move Fort Knox's service from TODP to RTS. Fort Knox currently operates on-site generation of more than 1 MW and the proposed provision enables Fort Knox to avoid paying ratchet demand charges for an LG&E system fault if it cannot return its on-site generation back to service within 15 minutes.

Q WHY IS IT IMPORTANT TO HAVE THIS PROVISION IN THE TARIFF?

A If Fort Knox is interrupted because of an LG&E system fault, the on-site generation is shut down. The on-site generation is shut down for safety reasons, however, even if the generation could be isolated from LG&E's system it is not capable of supplying the entire load requirement of the installation. Once LG&E's power is restored, it is necessary to synchronize the on-site generation with LG&E's system to avoid equipment damage. Under the current RTS rate provisions, a billing demand is based on a 15-minute period. If the customer cannot bring its generation on within 15 minutes a new billing demand could be established based on events that were outside of the customer's control. If this billing demand sets a new high, it would also be used to establish a new ratchet demand. This ratchet demand could set a minimum demand for billing purposes for the next 11 months. This results in the customer paying demand charges that are a result of an incident that is out of its control.

VIII. LG&E'S SUBSTITUTE GAS SALES SERVICE ("SGSS")

Q IS LG&E PROPOSING ANY CHANGES TO THE TERMS AND CONDITIONS OF SGSS?

A Yes. LG&E is proposing to eliminate the 70% demand ratchet provision in the Monthly Billing Demand provision of the tariff. LG&E is essentially replacing the 70% with 100%.

Q WHAT DO YOU PROPOSE FOR THE SGSS MONTHLY BILLING DEMAND PROVISION?

A The Commission should not eliminate the 70% demand ratchet provision. A 100% ratchet is punitive and does not reflect the usage diversity for gas customers that utilize the system. The cost components that are used to develop the monthly demand charge include transmission demand costs. Typically, the transmission system is designed to meet the system peak and not the non-coincident peaks or the total of all customers' maximum demands. A 70% ratchet factor reflects the diversity in individual customer demands at the time of system peak.

As a result, a customer in any given month will pay a demand charge based on the higher of the highest daily volume of gas delivered during the current month, or 70% of the daily volume demand created in the previous 11 monthly billing periods.

IX. DEPRECIATION EXPENSE

Q WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A In this section of my testimony I will propose a reduction to the Companies' proposed depreciation expense. My proposed adjustment is based on extending the currently approved life span of five of the Companies' coal units, based on what Mr. Spanos and the Companies describe as a "possible alternative" for these units.

Q PLEASE BRIEFLY EXPLAIN THE PURPOSE OF DEPRECIATION RATES AND DEPRECIATION EXPENSE.

A Depreciation rates and the associated depreciation expense are mechanisms for capital recovery for a regulated utility. Depreciation expense is a substantial portion of the Companies' revenue requirement. The depreciation rates that determine the depreciation expense are based on analysis of a company's accounting data and expectations for the future. The most appropriate depreciation rates will recover the cost of an asset providing utility service, adjusted for net salvage, over the estimated useful life of that asset.

Q WHAT IS YOUR PROPOSED ADJUSTMENT TO KU'S AND LG&E'S PROPOSED DEPRECIATION RATES AND EXPENSE?

A I propose that the currently approved life span for Mill Creek 1 and 2, Brown 3, and Ghent 1 and 2 be increased by three years. For KU, this reduces the depreciation expense for steam plant by $12,109,997. For LG&E, this reduces the depreciation expense for steam plant by $2,478,836.

Q WHY IS YOUR ADJUSTMENT REASONABLE?

A First, this adjustment is reasonable because both the Companies and Mr. Spanos, who conducted the Companies' depreciation studies, believe this adjustment is a possible alternative. In reviewing emails from Mr. Spanos to Company representatives, I discovered that Mr. Spanos had intended to increase the lives of these five units. The Companies have installed scrubbers on these coal units in order for these units to remain compliant with environmental regulations. If it is possible to extend the life span of these units, then they should be operated as long as possible, so that the customers get the most value out of both these units and the scrubbers that were installed on those units. Second, extending the lives of these five units by three years will not result in units that are outside the range of life spans of other steam base load units that the Companies have operated. KU's Tyrone plant, which was retired in 2015, had units that were 67 and 68 years old when retired. Lastly, this adjustment reduces the current rate increase burden on the Companies' customers by reducing the revenue requirement in these proceedings.

Q WHAT WILL BE THE AGE OF THE COAL UNITS AT THE TIME OF RETIREMENT UNDER YOUR PROPOSAL AND UNDER KU/LG&E'S PROPOSALS?

A I show this below in Table 1.

TABLE 1

Life Spans of Affected Units

Unit	KU/LG&E Proposed Life Span	DoD/FEA Proposed Life Span
Brown Unit 3	64	67
Ghent Unit 1	60	63
Ghent Unit 2	57	60
Mill Creek Unit 1	60	63
Mill Creek Unit 2	60	63

Q ARE THE RESULTING AGES OF THESE FIVE COAL UNITS CONSISTENT WITH THE AGES ASSUMED IN KU/LG&E'S INTEGRATED RESOURCE PLAN ("IRP") AND THE AGES OF OTHER PLANTS IN ITS FLEET?

A Yes. With the exception of Brown 3, the increase to the life span for Ghent 1 and 2 and Mill Creek 1 and 2 are within the range studied in the Companies' 2018 Integrated Resource Plan of 55 to 65 years. Further, the depreciation study for KU, Exhibit JJS-KU-1 at pages 36-37, shows that KU has operated units for as long as 68 years at the Tyrone plant and it intends to operate some portions of Trimble County 2 to an age of 76 years. Again, it is important to note that Mr. Spanos and the Companies considered this life extension as a possible alternative.

Q CAN YOU PRESENT NEW DEPRECIATION RATES CONSISTENT WITH YOUR PROPOSED ADJUSTMENT?

A Yes. In response to discovery US DoD-2 Question 8 requests from KU and LG&E, the Companies calculated the depreciation rates consistent with this proposed adjustment. These depreciation rates for KU are provided in Exhibit JTS-10 and in Exhibit JTS-11 for LG&E.

Q WHAT IS THE DEPRECIATION EXPENSE IMPACT OF USING YOUR PROPOSED DEPRECIATION RATES ON KU/LG&E'S DEPRECIATION EXPENSE?

A For KU, this reduces depreciation expense for steam plant by $12,109,997. For LG&E, this reduces the depreciation expense for steam plant by $2,478,836.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

QUALIFICATIONS OF JAMES T. SELECKY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal at Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978, I received the degree of Master of Business Administration with a major in Finance from Wayne State University.

I was employed by The Detroit Edison Company ("DECo") in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and troubleshooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies; developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DECo; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. At DBA and BAI I have testified in electric, gas and water proceedings involving almost all aspects of regulation. I have also performed economic analyses for clients related to energy cost issues.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have testified on behalf of DECo in its steam heating and main electric cases. In these cases I have testified to rate base, income statement adjustments, changes in book depreciation rates, rate design, and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of Alberta, Nova Scotia and Saskatchewan. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Hawaii, Kentucky, Montana, New York, Pennsylvania, Virginia and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, rate base adjustments, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates.

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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**	)	**Case No. 2018-00294**
In the Matter of: **ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES**	)	**Case No. 2018-00295**

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

VERIFICATION OF JAMES T. SELECKY

James T. Selecky, being first duly sworn, states the following: The prepared Direct Testimony and Exhibits constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

James T. Selecky

James T. Selecky

SUBSCRIBED and SWORN to before me this 16th day of January, 2019.

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

Tammy S Klossner

Notary Public

Exhibit JTS-1

Results of KU's Filed Electric Cost of Service Study

Witness: James T. Selecky

KENTUCKY UTILITIES COMPANY

Electric Cost of Service Study Results
Company Study
Twelve Months Ended April 30, 2020

		Present			Proposed		
Line	Rate Class	Rate of Return (1)	Index (2)	Subsidy (000) (3)	Rate of Return (4)	Index (5)	Subsidy (000) (6)
1	Residential - Rates RS, RTOD & VFD	3.03%	54	$ (65,282)	4.99%	65	$ (68,490)
2	General Service - Rate GS	11.31%	203	35,908	13.80%	180	38,444
3	All Electric Schools - Rate AES	6.70%	120	422	8.94%	117	485
4	Power Service - Rate PS - Secondary	11.18%	200	26,169	13.59%	177	27,706
5	Power Service - Rate PS - Primary	15.22%	273	3,037	18.05%	236	3,275
6	Time of Day Secondary - Rate TODS	6.15%	110	2,356	8.20%	107	2,200
7	Time of Day Primary - Rate TODP	4.50%	81	(8,674)	6.49%	85	(9,410)
8	Retail Transmission Service - Rate RTS	5.77%	103	462	8.00%	104	817
9	Fluctuating Load Service - Rate FLS	5.05%	90	(582)	6.95%	91	(783)
10	Lighting and Restricted Lighting - Rates LS & RLS	10.48%	188	6,265	12.11%	158	5,694
11	Lighting Energy Service - Rate LE	21.30%	382	23	21.30%	278	20
12	Traffic Energy Service - Rate TE	16.53%	296	43	16.43%	214	34
13	Outdoor Sports Lighting Service - Rate OSL	9.47%	170	8	11.32%	148	8
14	Electric Vehicle Charging - Rate EV	-9.39%	(168)	(25)	7.66%	100	0
15	Solar Share - Rate SSP	-2.75%	(49)	(131)	7.66%	100	0
16	Total System	5.58%	100	$ (0)	7.66%	100	$ 0

Exhibit JTS-2

Results of LG&E's Filed
Electric Cost of Service Study

Witness: James T. Selecky

LOUISVILLE GAS AND ELECTRIC COMPANY

Electric Cost of Service Study Results
Company Study
Twelve Months Ended April 30, 2020

		Present			Proposed		
Line	Rate Class	Rate of Return (1)	Index (2)	Subsidy (000) (3)	Rate of Return (4)	Index (5)	Subsidy (000) (6)
1	Residential - Rates RS, RTOD & VFD	2.69%	40	$ (73,313)	3.71%	48	$ (73,393)
2	General Service - Rate GS	11.74%	174	19,981	12.84%	166	20,272
3	Power Service - Rate PS - Secondary	14.44%	215	28,358	15.65%	202	29,040
4	Power Service - Rate PS - Primary	12.70%	189	1,173	13.94%	180	1,215
5	Time of Day Secondary - Rate TODS	9.50%	141	6,394	10.37%	134	6,051
6	Time of Day Primary - Rate TODP	9.52%	142	9,266	10.46%	135	8,960
7	Retail Transmission Service - Rate RTS	12.57%	187	7,233	13.72%	177	7,388
8	Special Contract	6.82%	101	8	7.94%	102	16
9	Lighting and Restricted Lighting - Rates LS & RLS	7.49%	111	842	8.07%	104	350
10	Lighting Energy Service - Rate LE	18.96%	282	51	18.96%	245	47
11	Traffic Energy Service - Rate TE	16.64%	247	58	16.63%	215	52
12	Outdoor Sports Lighting Service - Rate OSL	12.65%	188	2	13.52%	174	2
13	Electric Vehicle Charging - Rate EV	-7.48%	(111)	(26)	7.75%	100	(0)
14	Solar Share - Rate SSP	5.02%	75	(27)	7.75%	100	(0)
15	Business Solar - Rate BS	6.97%	104	0	7.75%	100	(0)
16	Total System	6.73%	100	$ (0)	7.75%	100	$ (0)

Exhibit JTS-3

DoD/FEA Proposed Revenue Allocation for KU at Requested Level

Witness: James T. Selecky

KENTUCKY UTILITIES COMPANY

Revenue Increase Allocation At Requested Level For Tier Rate Classes

Line	Tier	Present Revenues (1)	Proposed Revenue Increase (2)	Percent Increase (3)	DoD/FEA Revenue Increase (4)	Percent Increase (5)
1	1	$ 622,450,115	$ 50,440,057	8.10%	$ 56,642,960	9.10%
2	2	$ 465,112,879	$ 30,753,666	6.61%	$ 27,700,804	5.96%
3	3	$ 518,915,396	$ 31,732,619	6.12%	$ 28,582,578	5.51%
4	4	$ 289,144	$ -	0.00%	$ -	0.00%
5	Total	$ 1,606,767,534	$ 112,926,342	7.03%	$ 112,926,342	7.03%

	Tier	Proposed Revenue Increase (1)	Percent of Proposed Revenue Increase (2)	DoD/FEA Revenue Increase Adjustment (3)
6	2	$ 30,753,666	49.22%	$ (3,052,862)
7	3	$ 31,732,619	50.78%	$ (3,150,041)
8	Total	$ 62,486,285	100.00%	$ (6,202,903)
9	1			$ 6,202,903

Exhibit JTS-4

DoD/FEA Proposed Revenue Allocation for LG&E at Requested Level

Witness: James T. Selecky

LOUISVILLE GAS AND ELECTRIC COMPANY

Revenue Increase Allocation At Requested Level For Tier Rate Classes

Line	Tier	Present Revenues (1)	Proposed Revenue Increase (2)	Percent Increase (3)	DoD/FEA Revenue Increase (4)	Percent Increase (5)
1	1	$ 459,888,134	$ 18,799,090	4.09%	$ 28,007,187	6.09%
2	2	$ 371,399,367	$ 9,869,747	2.66%	$ 4,337,409	1.17%
3	3	$ 312,727,314	$ 6,557,592	2.10%	$ 2,881,833	0.92%
4	4	$ 635,162	$ -	0.00%	$ -	0.00%
5	Total	$ 1,144,649,977	$ 35,226,429	3.08%	$ 35,226,429	3.08%

Line	Tier	Proposed Revenue Increase (1)	Percent of Proposed Revenue Increase (2)	DoD/FEA Revenue Increase Adjustment (3)
6	2	$ 9,869,747	60.08%	$ (5,532,338)
7	3	$ 6,557,592	39.92%	$ (3,675,759)
8	Total	$ 16,427,339	100.00%	$ (9,208,097)
9	1			$ 9,208,097

Exhibit JTS-5

KU/LG&E Monthly CP Demands Analysis 2013-2017

Witness: James T. Selecky

Exhibit JTS-5

KU & LGE Monthly Peak Demands

2013			2014			2015		
Month	Peak MW	Peak %	Month	Peak MW	Peak %	Month	Peak MW	Peak %
1	5,907	92%	1	7,114	100%	1	6,833	97%
2	5,901	92%	2	6,290	88%	2	7,079	100%
3	5,346	83%	3	5,756	81%	3	5,973	84%
4	4,540	71%	4	4,643	65%	4	4,240	60%
5	5,654	88%	5	5,562	78%	5	5,314	75%
6	6,288	98%	6	6,270	88%	6	6,262	88%
7	6,409	100%	7	6,313	89%	7	6,392	90%
8	6,333	98%	8	6,255	88%	8	6,208	88%
9	6,434	100%	9	6,192	87%	9	6,199	88%
10	5,235	81%	10	5,207	73%	10	4,802	68%
11	5,165	80%	11	5,680	80%	11	5,015	71%
12	5,721	89%	12	5,313	75%	12	5,026	71%

2016			2017			Average of 2013-2017		
Month	Peak MW	Peak %	Month	Peak MW	Peak %	Month	Peak MW	Peak %
1	6,223	96%	1	5,679	87%	1	6,351	99%
2	5,780	90%	2	5,229	80%	2	6,056	94%
3	4,843	75%	3	5,434	84%	3	5,470	85%
4	4,791	74%	4	4,708	72%	4	4,584	71%
5	5,289	82%	5	5,446	84%	5	5,453	85%
6	6,334	98%	6	6,078	93%	6	6,246	97%
7	6,458	100%	7	6,503	100%	7	6,415	100%
8	6,451	100%	8	6,233	96%	8	6,296	98%
9	6,291	97%	9	5,763	89%	9	6,176	96%
10	5,114	79%	10	4,807	74%	10	5,033	78%
11	4,809	74%	11	4,853	75%	11	5,104	80%
12	5,813	90%	12	5,612	86%	12	5,497	86%

Exhibit JTS-6

KU's Cost of Service Results Using DoD/FEA 6 CP Allocator for Production and Transmission

Witness: James T. Selecky

KENTUCKY UTILITIES COMPANY

Electric Cost of Service Study Results
DoD/FEA 6 CP Allocator for Production and Transmission
Twelve Months Ended April 30, 2020

Line	Rate Class	Present Rate of Return (1)	Present Index (2)	Present Subsidy (000) (3)
1	Residential - Rates RS, RTOD & VFD	2.41%	43	$ (84,868)
2	General Service - Rate GS	13.76%	247	45,878
3	All Electric Schools - Rate AES	4.53%	81	(443)
4	Power Service - Rate PS - Secondary	11.66%	209	27,868
5	Power Service - Rate PS - Primary	14.90%	267	2,981
6	Time of Day Secondary - Rate TODS	6.33%	113	3,068
7	Time of Day Primary - Rate TODP	5.12%	92	(3,598)
8	Retail Transmission Service - Rate RTS	6.24%	112	1,558
9	Fluctuating Load Service - Rate FLS	6.94%	124	1,320
10	Lighting and Restricted Lighting - Rates LS & RLS	10.56%	189	6,310
11	Lighting Energy Service - Rate LE	26.76%	480	26
12	Traffic Energy Service - Rate TE	15.06%	270	39
13	Outdoor Sports Lighting Service - Rate OSL	18.70%	335	18
14	Electric Vehicle Charging - Rate EV	-9.39%	(168)	(25)
15	Solar Share - Rate SSP	-2.75%	(49)	(131)
16	Total System	5.58%	100	$ (0)

Exhibit JTS-7

LG&E's Cost of Service Results Using DoD/FEA 6 CP Allocator for Production and Transmission

Witness: James T. Selecky

LOUISVILLE GAS AND ELECTRIC COMPANY

Electric Cost of Service Study Results
DoD/FEA 6 CP Allocator for Production and Transmission
Twelve Months Ended April 30, 2020

		Present		
Line	Rate Class	Rate of Return	Index	Subsidy (000)
		(1)	(2)	(3)
1	Residential - Rates RS, RTOD & VFD	2.77%	41	$ (71,616)
2	General Service - Rate GS	12.44%	185	22,081
3	Power Service - Rate PS - Secondary	13.51%	201	25,835
4	Power Service - Rate PS - Primary	12.40%	184	1,125
5	Time of Day Secondary - Rate TODS	9.12%	136	5,618
6	Time of Day Primary - Rate TODP	9.84%	146	10,173
7	Retail Transmission Service - Rate RTS	12.22%	182	6,886
8	Special Contract	5.66%	84	(99)
9	Lighting and Restricted Lighting - Rates LS & RLS	6.71%	100	(21)
10	Lighting Energy Service - Rate LE	10.09%	150	19
11	Traffic Energy Service - Rate TE	14.17%	211	48
12	Outdoor Sports Lighting Service - Rate OSL	25.52%	379	4
13	Electric Vehicle Charging - Rate EV	-7.48%	(111)	(26)
14	Solar Share - Rate SSP	5.02%	75	(27)
15	Business Solar - Rate BS	6.97%	104	0
16	Total System	6.73%	100	$ (0)

Exhibit JTS-8

Summary of DoD/FEA
KU Cost of Service Study

Witness: James T. Selecky

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended April 30, 2020

DoD/FEA 6 CP Production and Transmission Methodology

Description	Total System	Residential Rate RS	General Service GS	All Electric Schools AES	Power Service PS-Secondary	Power Service PS-Primary	Time of Day TOD-Secondary	Time of Day TOD-Primary
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Pro-Forma Operating Revenue	$ 1,447,651,428	$ 570,112,617	$ 199,411,303	$ 10,930,845	$ 157,207,543	$ 12,435,763	$ 127,417,002	$ 244,087,359
Operating Expenses								
Operation and Maintenance Expenses	$ 884,639,921	$ 361,561,371	$ 99,115,454	$ 6,702,015	$ 81,079,940	$ 6,180,903	$ 79,004,462	$ 162,074,806
Depreciation and Amortization Expenses	268,954,148	130,098,192	26,505,113	2,149,779	23,821,092	1,665,371	21,390,199	40,576,585
Regulatory Credits and Accretion Expenses	-	-	-	-	-	-	-	-
Property Taxes	30,253,263	14,954,762	3,103,887	236,692	2,581,361	179,291	2,296,470	4,338,316
Other Taxes	13,428,960	6,639,769	1,378,173	105,089	1,146,117	79,615	1,019,592	1,926,146
Gain Disposition of Allowances	-	-	-	-	-	-	-	-
State and Federal Income Taxes	24,634,790	$ 500,106	$ 10,138,664	$ 154,033	$ 6,850,657	$ 642,709	$ 2,689,938	$ 3,404,231
Specific Assignment of Curtailable Service Rider Credit	(18,175,605)	-	-	-	-	-	-	(1,041,226)
Total Operating Expenses	$ 1,221,911,083	$ 521,877,260	$ 141,777,515	$ 9,503,497	$ 117,292,468	$ 8,877,105	$ 108,073,524	$ 214,489,676
Net Operating Income (Adjusted)	$ 225,740,344	$ 48,235,357	$ 57,633,789	$ 1,427,348	$ 39,915,076	$ 3,558,659	$ 19,343,478	$ 29,597,683
Adjusted Net Cost Rate Base	$ 4,045,218,982	$ 1,999,844,095	$ 418,968,733	$ 31,508,368	$ 342,417,337	$ 23,888,123	$ 305,588,396	$ 578,526,674
Rate of Return	**5.58%**	**2.41%**	**13.76%**	**4.53%**	**11.66%**	**14.90%**	**6.33%**	**5.12%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended April 30, 2020

DoD/FEA 6 CP Production and Transmission Methodology

Description	Retail Transmission Service RTS - Transmission	Fluctuating Load Service FLS - Transmission	Outdoor Lighting LS & RLS	Lighting Energy LE	Traffic Energy TE	Outdoor Sports Lighting OSL	Electric Vehicle Charging EV	Solar Share SSP
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Pro-Forma Operating Revenue	$ 80,134,844	$ 18,582,613	$ 26,968,523	$ 84,843	$ 164,762	$ 51,869	$ 8,320	$ 53,220
Operating Expenses								
Operation and Maintenance Expenses	$ 55,767,836	$ 23,411,481	$ 9,509,257	$ 49,308	$ 86,602	$ 21,787	$ 6,399	$ 68,299
Depreciation and Amortization Expenses	12,609,920	5,219,092	4,855,418	5,384	19,060	6,118	14,048	18,775
Regulatory Credits and Accretion Expenses	-	-	-	-	-	-	-	-
Property Taxes	1,316,712	544,441	690,445	647	2,269	762	1,989	5,221
Other Taxes	584,618	241,726	306,481	287	1,008	338	-	-
Gain Disposition of Allowances	-	-	-	-	-	-	-	-
State and Federal Income Taxes	$ 890,259	$ (2,233,538)	$ 1,590,501	$ 4,691	$ 8,311	$ 3,510	$ (2,463)	$ (6,819)
Specific Assignment of Curtailable Service Rider Credit	(3,055,799)	(14,078,580)	-	-	-	-	-	-
Total Operating Expenses	$ 69,176,822	$ 13,545,800	$ 16,980,318	$ 60,595	$ 118,278	$ 32,776	$ 19,973	$ 85,477
Net Operating Income (Adjusted)	$ 10,958,022	$ 5,036,813	$ 9,988,205	$ 24,248	$ 46,485	$ 19,093	$ (11,653)	$ (32,257)
Adjusted Net Cost Rate Base	$ 175,523,475	$ 72,598,859	$ 94,556,218	$ 90,615	$ 308,764	$ 102,089	$ 124,112	$ 1,173,128
Rate of Return	**6.24%**	**6.94%**	**10.56%**	**26.76%**	**15.06%**	**18.70%**	**-9.39%**	**-2.75%**

Exhibit JTS-9

Summary of DoD/FEA
LG&E Cost of Service Study

Witness: James T. Selecky

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation
12 Months Ended April 30, 2020

DoD/FEA 6 CP Production and Transmission Methodology

Description	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Pro-Forma Operating Revenue	$ 1,013,722,856	$ 410,256,536	$ 139,127,778	$ 8,261,980	$ 152,688,238	$ 133,391,644	$ 88,022,175	$ 58,246,966
Operating Expenses								
Operation and Maintenance Expenses	$ 627,292,493	$ 270,225,303	$ 73,229,214	$ 4,865,175	$ 83,434,598	$ 88,207,108	$ 55,168,094	$ 42,405,789
Depreciation and Amortization Expenses	155,800,380	82,448,566	17,653,198	916,609	17,635,584	15,017,087	10,877,854	5,790,186
Property and Other Taxes	34,932,925	18,663,740	3,959,782	200,935	3,881,391	3,286,701	2,386,291	1,243,704
Amortization of Investment Tax Credit	(1,004,121)	(533,510)	(113,118)	(5,730)	(110,705)	(93,701)	(68,043)	(35,404)
State and Federal Income Taxes	25,285,778	(908,245)	7,719,662	398,760	8,517,390	4,238,359	3,093,349	1,304,104
Specific Assignment of Interruptible Credit	(6,324,976)	-	-	-	-	(2,062,957)	-	(4,262,018)
Allocation of Interruptible Credits	6,324,976	2,996,636	714,025	46,347	860,908	769,554	546,461	343,569
Total Operating Expenses	$ 842,307,455	$ 372,892,489	$ 103,162,764	$ 6,422,097	$ 114,219,166	$ 109,362,151	$ 72,004,006	$ 46,789,930
Net Operating Income -- Pro-Forma	$ 171,415,400	$ 37,364,047	$ 35,965,014	$ 1,839,884	$ 38,469,072	$ 24,029,493	$ 16,018,169	$ 11,457,035
Cost of Service Summary -- Pro-Forma								
Net Operating Income -- Pro-Forma	$ 171,415,400	$ 37,364,047	$ 35,965,014	$ 1,839,884	$ 38,469,072	$ 24,029,493	$ 16,018,169	$ 11,457,035
Adjusted Net Cost Rate Base	$ 2,548,077,151	$ 1,351,314,600	$ 289,216,148	$ 14,843,225	$ 284,720,267	$ 244,140,053	$ 175,675,376	$ 93,776,075
Rate of Return	**6.73%**	**2.77%**	**12.44%**	**12.40%**	**13.51%**	**9.84%**	**9.12%**	**12.22%**

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation
12 Months Ended April 30, 2020

DoD/FEA 6 CP Production and Transmission Methodology

Description	Special Contract Customer	Street Lighting Rate RLS, LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE	Outdoor Sports Lighting Rate OSL	Electric Vehicle Charging Rate EV	Solar Share Rate SSP	Business Solar Rate BS
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Pro-Forma Operating Revenue	$ 3,452,909	$ 19,541,965	$ 258,694	$ 295,372	$ 7,965	$ 13,277	$ 147,420	$ 9,936
Operating Expenses								
Operation and Maintenance Expenses	$ 2,466,213	$ 6,875,147	$ 175,916	$ 175,528	$ 2,310	$ 8,436	$ 53,663	$ -
Depreciation and Amortization Expenses	426,273	4,942,707	25,001	29,072	829	15,654	17,632	4,127
Property and Other Taxes	93,608	1,197,011	5,639	6,556	200	2,510	4,727	129
Amortization of Investment Tax Credit	(2,669)	(34,383)	(161)	(187)	(6)	-	(5,429)	(1,074)
State and Federal Income Taxes	55,097	827,192	8,594	15,172	914	(2,926)	16,873	1,483
Specific Assignment of Interruptible Credit	-	-	-	-	-	-	-	-
Allocation of Interruptible Credits	21,224	24,187	950	1,110	5	-	-	-
Total Operating Expenses	$ 3,059,745	$ 13,831,861	$ 215,938	$ 227,251	$ 4,253	$ 23,674	$ 87,466	$ 4,665
Net Operating Income -- Pro-Forma	$ 393,163	$ 5,710,104	$ 42,756	$ 68,122	$ 3,712	$ (10,397)	$ 59,955	$ 5,271
Cost of Service Summary -- Pro-Forma								
Net Operating Income -- Pro-Forma	$ 393,163	$ 5,710,104	$ 42,756	$ 68,122	$ 3,712	$ (10,397)	$ 59,955	$ 5,271
Adjusted Net Cost Rate Base	$ 6,947,967	$ 85,115,755	$ 423,936	$ 480,663	$ 14,547	$ 139,009	$ 1,193,920	$ 75,609
Rate of Return	**5.66%**	**6.71%**	**10.09%**	**14.17%**	**25.52%**	**-7.48%**	**5.02%**	**6.97%**

Exhibit JTS-10

KU's Response to US DOD-2
Question No. 8

Witness: James T. Selecky

KENTUCKY UTILITIES COMPANY

Response to Supplemental Request for Information of the U. S. Department of Defense
Dated December 13, 2018

Case No. 2018-00294

Question No. 8

Responding Witness: Daniel K. Arbough / John J. Spanos

Q-8. Please refer to page 799 of Attachment 1 to Response to US DOD-1 Question No. 26.

a. Please explain why the Company did not extend the lifespan of Mill Creek 1 and 2, Brown 3, and Ghent 1 and 2 by three years as Mr. Spanos had intended.

b. Please explain why Mr. Spanos thought the lives of these units should be extended by three years.

c. Please provide the impact on depreciation rates and test year depreciation expense for these units by extending the lives by three years.

d. Please provide the remaining life for each FERC account for each unit if the life was extended by three years such that Table 1 of the depreciation study (Exhibit JJS-KU-1) can be updated.

e. Please provide the interim retirements for each plant FERC account for each plant if the life was extended by three years such that Table 2 of the Depreciation Study (Exhibit JJS-KU-1) can be updated.

A-8.

a. The request misstates the email referenced therein. The email (page 799 of Attachment 1) discussion relates to a possible alternative to some of the steam units. Based on discussions with Company personnel it was determined this alternative was not consistent with the outlook of the units.

b. Mr. Spanos did not think the lives of these units should be extended by three years. Page 799 was an email discussing the possible alternative of extending the currently approved life span by three years.

c. See attached which sets forth the results for extending the designated units by three years. This calculation reduces depreciation expense for steam plant by $12,109,997 as compared to the depreciation study filed.

d. See attached for remaining lives by unit and account with the changed probable retirement dates for some units.

e. See attached for interim retirements for each account and unit for the facilities with a changed probable retirement date of three years.

	Filed	Rates Using 3 plus Years	Variance
Depreciation Expense	358,688,938.28	346,578,941.76	(12,109,996.52)

DESCRIPTION	**Filed**	**Rates Using 3 plus Years**	**Variance**
KU-130100- KY Organization	0.00%	0.00%	0.00%
KU-130100- VA Organization	0.00%	0.00%	0.00%
KU-130200-Franchises and Consents	3.63%	3.63%	0.00%
KU-130200-Licensed Project Franchi	3.63%	3.63%	0.00%
KU-130300-Misc Intangible Plant	20.96%	20.96%	0.00%
KU-130310-CCS Software	10.06%	10.06%	0.00%
KU-131020-EWB 1 Land	0.00%	0.00%	0.00%
KU-131020-EWB 3 Land	0.00%	0.00%	0.00%
KU-131020-EWB 3 Land ECR 2011	0.00%	0.00%	0.00%
KU-131020-GH 1 Land	0.00%	0.00%	0.00%
KU-131020-GH 4 Land ECR 2009	0.00%	0.00%	0.00%
KU-131020-GH 4 Land ECR 2016	0.00%	0.00%	0.00%
KU-131020-GR 1&2 Land	0.00%	0.00%	0.00%
KU-131020-PI 1&2 Land	0.00%	0.00%	0.00%
KU-131020-PI 3 Land	0.00%	0.00%	0.00%
KU-131020-TC 2 Land	0.00%	0.00%	0.00%
KU-131020-TC 2 Land ECR 2009	0.00%	0.00%	0.00%
KU-131020-TY 3 Land	0.00%	0.00%	0.00%
KU-131100-EWB 1 Structures and Imp	0.04%	0.04%	0.00%
KU-131100-EWB 2 Structures and Imp	0.63%	0.63%	0.00%
KU-131100-EWB 3 Struc	3.17%	2.71%	-0.46%
KU-131100-EWB 3 Struc ECR 2005	3.17%	2.71%	-0.46%
KU-131100-EWB 3 Struc ECR 2009	3.17%	2.71%	-0.46%
KU-131100-EWB 3 Struc ECR 2011	3.17%	2.71%	-0.46%
KU-131100-EWB3 FGD Struc	4.54%	3.88%	-0.66%
KU-131100-EWB3 FGD Struc ECR 2005	4.54%	3.88%	-0.66%
KU-131100-GH 1 Struc	1.68%	1.53%	-0.15%
KU-131100-GH 1 Struc ECR 2006	1.68%	1.53%	-0.15%
KU-131100-GH 1SC Structures and Im	1.14%	1.07%	-0.07%
KU-131100-GH 2 Structures and Impr	1.31%	1.22%	-0.09%
KU-131100-GH 3 Struc	2.15%	2.25%	0.10%
KU-131100-GH 3 Struc ECR 2006	2.15%	2.25%	0.10%
KU-131100-GH 3 Struc ECR 2011	2.15%	2.25%	0.10%
KU-131100-GH 4 Struc	3.44%	3.53%	0.09%
KU-131100-GH 4 Struc ECR 2005	3.44%	3.53%	0.09%
KU-131100-GH 4 Struc ECR 2006	3.44%	3.53%	0.09%

KU-131100-GH 4 Struc ECR 2009	3.44%	3.53%	0.09%
KU-131100-GH2 FGD Structures and I	1.16%	1.09%	-0.07%
KU-131100-GH3 FGD Structures and I	0.00%	0.00%	0.00%
KU-131100-GH4 FGD Structures and I	0.00%	5.41%	5.41%
KU-131100-GR 1-2 Structures and Im	0.00%	0.00%	0.00%
KU-131100-GR 3 Structures and Impr	0.00%	0.00%	0.00%
KU-131100-GR 4 Structures and Impr	0.00%	0.00%	0.00%
KU-131100-PI 1-2 Structures and Imp	0.00%	0.00%	0.00%
KU-131100-PI 3 Structures and Impr	0.00%	0.00%	0.00%
KU-131100-SL Structures and Improv	1.54%	1.54%	0.00%
KU-131100-TC 2 FGD Struc & Improv	1.21%	1.21%	0.00%
KU-131100-TC2 Struct	1.81%	1.81%	0.00%
KU-131100-TC2 Struct ECR 2006	1.81%	1.81%	0.00%
KU-131100-TC2 Struct ECR 2009	1.81%	1.81%	0.00%
KU-131100-TY 1&2 Structures and Im	0.00%	0.00%	0.00%
KU-131100-TY 3 Structures and Impr	0.00%	0.00%	0.00%
KU-131101-AROP EWB 1 Struct & Imp	0.00%	0.00%	0.00%
KU-131101-AROP EWB 3 ECR 2009	0.00%	0.00%	0.00%
KU-131101-AROP EWB 3 Struct & Imp	0.00%	0.00%	0.00%
KU-131101-AROP GH 1 Struct & Imp	0.00%	0.00%	0.00%
KU-131101-AROP GR 1-2 Struct & Imp	0.00%	0.00%	0.00%
KU-131101-AROP GR 4 Struct & Impr	0.00%	0.00%	0.00%
KU-131101-AROP TC2 Struct ECR 2009	0.00%	0.00%	0.00%
KU-131101-AROP TY 3 Struct & Impr	0.00%	0.00%	0.00%
KU-131200-EWB 1 Boil	3.21%	3.21%	0.00%
KU-131200-EWB 1 Boil - Ash Pond	24.68%	7.82%	-16.86%
KU-131200-EWB 1 Boil ECR 2005	3.21%	3.21%	0.00%
KU-131200-EWB 1 Boil ECR 2011	3.21%	3.21%	0.00%
KU-131200-EWB 2 Boil	3.08%	3.08%	0.00%
KU-131200-EWB 2 Boil ECR 2005	3.08%	3.08%	0.00%
KU-131200-EWB 2 Boil ECR 2006	3.08%	3.08%	0.00%
KU-131200-EWB 2 Boil ECR 2011	3.08%	3.08%	0.00%
KU-131200-EWB 3 Boil	5.19%	4.46%	-0.73%
KU-131200-EWB 3 Boil Ash Pond	24.68%	24.68%	0.00%
KU-131200-EWB 3 Boil ECR 2005	5.19%	4.46%	-0.73%
KU-131200-EWB 3 Boil ECR 2006	5.19%	4.46%	-0.73%
KU-131200-EWB 3 Boil ECR 2009	5.19%	4.46%	-0.73%
KU-131200-EWB 3 Boil ECR 2011	5.19%	4.46%	-0.73%
KU-131200-EWB 3 ECR 2016 Plan	5.19%	5.19%	0.00%
KU-131200-EWB 3 ECR 2018 Plan	5.19%	5.19%	0.00%
KU-131200-EWB ECR Future Plan	5.19%	5.19%	0.00%
KU-131200-EWB3 FGD Boil	4.92%	4.23%	-0.69%

KU-131200-EWB3 FGD Boil ECR 2005	4.92%	4.23%	-0.69%
KU-131200-GH 1 Boil	4.83%	4.22%	-0.61%
KU-131200-GH 1 Boil - Ash Pond	0.26%	0.26%	0.00%
KU-131200-GH 1 Boil ECR 2005	4.83%	4.22%	-0.61%
KU-131200-GH 1 Boil ECR 2006	4.83%	4.22%	-0.61%
KU-131200-GH 1 Boil ECR 2011	4.83%	4.22%	-0.61%
KU-131200-GH 1 Boil ECR 2016	4.83%	4.83%	0.00%
KU-131200-GH 1 SC Boil - Ash Pond	0.23%	0.23%	0.00%
KU-131200-GH 1SC Boil	4.16%	3.65%	-0.51%
KU-131200-GH 1SC Boil ECR 2005	4.16%	3.65%	-0.51%
KU-131200-GH 1SC Boil ECR 2016	4.16%	3.65%	-0.51%
KU-131200-GH 2 Boil	5.10%	4.45%	-0.65%
KU-131200-GH 2 Boil ECR 2005	5.10%	4.45%	-0.65%
KU-131200-GH 2 Boil ECR 2011	5.10%	4.45%	-0.65%
KU-131200-GH 2 Boil ECR 2016	5.10%	5.10%	0.00%
KU-131200-GH 2 SC Boil - Ash Pond	0.00%	0.00%	0.00%
KU-131200-GH 2SC Boil	1.19%	1.12%	-0.07%
KU-131200-GH 2SC Boil ECR 2005	1.19%	1.12%	-0.07%
KU-131200-GH 2SC Boil ECR 2016	1.19%	1.12%	-0.07%
KU-131200-GH 3 Boil	3.54%	3.65%	0.11%
KU-131200-GH 3 Boil ECR 2006	3.54%	3.65%	0.11%
KU-131200-GH 3 Boil ECR 2011	3.54%	3.65%	0.11%
KU-131200-GH 3 Boil ECR 2016	3.54%	3.54%	0.00%
KU-131200-GH 4 Boil	4.35%	4.45%	0.10%
KU-131200-GH 4 Boil - Ash Pond	14.06%	14.06%	0.00%
KU-131200-GH 4 Boil ECR 2005	4.35%	4.45%	0.10%
KU-131200-GH 4 Boil ECR 2006	4.35%	4.45%	0.10%
KU-131200-GH 4 Boil ECR 2009	4.35%	4.45%	0.10%
KU-131200-GH 4 Boil ECR 2011	4.35%	4.45%	0.10%
KU-131200-GH 4 Boil ECR 2016	4.35%	4.45%	0.10%
KU-131200-GH3 FGD Boil	3.99%	4.10%	0.11%
KU-131200-GH3 FGD Boil ECR 2005	3.99%	4.10%	0.11%
KU-131200-GH3 FGD Boil ECR 2016	3.99%	4.10%	0.11%
KU-131200-GH4 FGD Boil	3.57%	3.67%	0.10%
KU-131200-GH4 FGD Boil ECR 2005	3.57%	3.67%	0.10%
KU-131200-GH4 FGD Boil ECR 2016	3.57%	3.67%	0.10%
KU-131200-Ghent ECR 2018 Plan	4.35%	4.35%	0.00%
KU-131200-Ghent ECR Future Plan	4.35%	4.35%	0.00%
KU-131200-GR 1-2 Boiler Plant Equi	0.00%	0.00%	0.00%
KU-131200-GR 3 Boil	0.00%	0.00%	0.00%
KU-131200-GR 3 Boil - Ash Pond	0.00%	0.00%	0.00%
KU-131200-GR 3 Boil ECR 2006	0.00%	0.00%	0.00%

KU-131200-GR 4 Boil	0.00%	0.00%	0.00%
KU-131200-GR 4 Boil ECR 2006	0.00%	0.00%	0.00%
KU-131200-GR 4 Boil ECR 2016	0.00%	0.00%	0.00%
KU-131200-GR ECR Future Plan	0.00%	0.00%	0.00%
KU-131200-PI 1-2 Boiler Plant Equip	0.00%	0.00%	0.00%
KU-131200-PI 3 Boil - Ash Pond	0.00%	0.00%	0.00%
KU-131200-PI 3 Boiler Plant Equipm	0.00%	0.00%	0.00%
KU-131200-PI ECR 2016	0.00%	0.00%	0.00%
KU-131200-PI ECR Future Plan	0.00%	0.00%	0.00%
KU-131200-TC 2 Boil	2.17%	2.17%	0.00%
KU-131200-TC 2 Boil - Ash Pond	7.48%	7.48%	0.00%
KU-131200-TC 2 Boil ECR 2006	2.17%	2.17%	0.00%
KU-131200-TC 2 Boil ECR 2009	2.17%	2.17%	0.00%
KU-131200-TC 2 Boil ECR 2009-Ash Po	7.48%	7.48%	0.00%
KU-131200-TC 2 Boil ECR 2016	2.17%	2.17%	0.00%
KU-131200-TC ECR 2018 Plan	2.17%	2.17%	0.00%
KU-131200-TC ECR Future Plan	2.17%	2.17%	0.00%
KU-131200-TC2 FGD Boil	1.96%	1.96%	0.00%
KU-131200-TC2 FGD Boil ECR 2006	1.96%	1.96%	0.00%
KU-131200-TY 1&2 Boiler Plant Equi	0.00%	0.00%	0.00%
KU-131200-TY 3 Boil	0.00%	0.00%	0.00%
KU-131200-TY 3 Boil - Ash Pond	0.00%	0.00%	0.00%
KU-131200-TY 3 Boil ECR 2006	0.00%	0.00%	0.00%
KU-131200-TY 3 Boil ECR 2016	0.00%	0.00%	0.00%
KU-131200-TY ECR Future Plan	0.00%	0.00%	0.00%
KU-131201-AROP EWB 1 Boiler Plt Eqp	0.00%	0.00%	0.00%
KU-131201-AROP EWB 3 Boiler Plt Eqp	0.00%	0.00%	0.00%
KU-131201-AROP GH 1 Boiler Plt Equp	0.00%	0.00%	0.00%
KU-131201-AROP GH 1SC Boiler Plt Eq	0.00%	0.00%	0.00%
KU-131201-AROP GH 2 Boiler Plt Equp	0.00%	0.00%	0.00%
KU-131201-AROP GH 4 Boiler Plt Equp	0.00%	0.00%	0.00%
KU-131201-AROP GR 1-2 Boiler Plt Eq	0.00%	0.00%	0.00%
KU-131201-AROP GR 4 Boiler Plt Equp	0.00%	0.00%	0.00%
KU-131201-AROP TY 1-2 Boiler Plt Eq	0.00%	0.00%	0.00%
KU-131201-AROP TY 3 Boiler Plt Equp	0.00%	0.00%	0.00%
KU-131400-EWB 1 Turbogenerator Uni	2.52%	2.52%	0.00%
KU-131400-EWB 2 Turbogenerator Uni	1.62%	1.62%	0.00%
KU-131400-EWB 3 Turbogenerator Uni	5.29%	4.57%	-0.72%
KU-131400-GH 1 Turbogenerator Unit	3.34%	2.96%	-0.38%
KU-131400-GH 2 Turbogenerator Unit	2.62%	2.37%	-0.25%
KU-131400-GH 3 Turbogenerator Unit	2.12%	2.24%	0.12%
KU-131400-GH 4 Turbogenerator Unit	2.64%	2.74%	0.10%

KU-131400-GR 1&2 Turbogenerator Un	0.00%	0.00%	0.00%
KU-131400-GR 3 Turbogenerator Unit	0.00%	0.00%	0.00%
KU-131400-GR 4 Turbogenerator Unit	0.00%	0.00%	0.00%
KU-131400-PI 1-2 Turbogenerator Uni	0.00%	0.00%	0.00%
KU-131400-PI 3 Turbogenerator Unit	0.00%	0.00%	0.00%
KU-131400-TC 2 Turbogenerator Unit	2.14%	2.14%	0.00%
KU-131400-TY 1&2 Turbogenerator Un	0.00%	0.00%	0.00%
KU-131400-TY 3 Turbogenerator Unit	0.00%	0.00%	0.00%
KU-131401-AROP TY 3 Turbogenerator	0.00%	0.00%	0.00%
KU-131500-EWB 1 Accessory Electric	1.24%	1.24%	0.00%
KU-131500-EWB 2 Acc	2.00%	2.00%	0.00%
KU-131500-EWB 2 Acc ECR 2005	2.00%	2.00%	0.00%
KU-131500-EWB 3 Acc	3.74%	3.20%	-0.54%
KU-131500-EWB 3 Acc ECR 2005	3.74%	3.20%	-0.54%
KU-131500-EWB 3 Acc ECR 2011	3.74%	3.20%	-0.54%
KU-131500-EWB 3 FGD Acc	4.75%	4.06%	-0.69%
KU-131500-EWB3 FGD Acc ECR 2005	4.75%	4.06%	-0.69%
KU-131500-GH 1 Access ECR 2011	2.37%	2.12%	-0.25%
KU-131500-GH 1 Accessory Electric	2.37%	2.12%	-0.25%
KU-131500-GH 1SC Acc	3.69%	3.23%	-0.46%
KU-131500-GH 1SC Acc ECR 2005	3.69%	3.23%	-0.46%
KU-131500-GH 2 Acc ECR 2011	1.66%	1.53%	-0.13%
KU-131500-GH 2 Accessory Electric	1.66%	1.53%	-0.13%
KU-131500-GH 2SC Acc	4.85%	4.21%	-0.64%
KU-131500-GH 2SC Acc ECR 2005	4.85%	4.21%	-0.64%
KU-131500-GH 3 Acc ECR 2011	1.73%	1.84%	0.11%
KU-131500-GH 3 Accessory Electric	1.73%	1.84%	0.11%
KU-131500-GH 4 Acc ECR 2009	3.56%	3.65%	0.09%
KU-131500-GH 4 Acc ECR 2011	3.56%	3.65%	0.09%
KU-131500-GH 4 Accessory Electric	3.56%	3.65%	0.09%
KU-131500-GH3 FGD Acc	3.66%	3.76%	0.10%
KU-131500-GH3 FGD Acc ECR 2005	3.66%	3.76%	0.10%
KU-131500-GH4 FGD Acc	4.15%	4.25%	0.10%
KU-131500-GH4 FGD Acc ECR 2005	4.15%	4.25%	0.10%
KU-131500-GR 1&2 Accessory Electri	0.00%	0.00%	0.00%
KU-131500-GR 3 Accessory Electric	0.00%	0.00%	0.00%
KU-131500-GR 4 Accessory Electric	0.00%	0.00%	0.00%
KU-131500-PI 1-2 Accessory Electric	0.00%	0.00%	0.00%
KU-131500-PI 3 Accessory Electric	0.00%	0.00%	0.00%
KU-131500-TC 2 Acc	1.99%	1.99%	0.00%
KU-131500-TC 2 Acc ECR 2006	1.99%	1.99%	0.00%
KU-131500-TC 2 Acc ECR 2009	1.99%	1.99%	0.00%

KU-131500-TC 2 FGD Accessory Equip	1.42%	1.42%	0.00%
KU-131500-TY 1&2 Accessory Electri	0.00%	0.00%	0.00%
KU-131500-TY 3 Accessory Electric	0.00%	0.00%	0.00%
KU-131501-AROP EWB 1 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP EWB 2 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP EWB 3 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP GH 1 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP GH 2 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP GH 3 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP GH 4 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP GR 4 Acc Electric	0.00%	0.00%	0.00%
KU-131501-AROP TY 3 Acc Electric	0.00%	0.00%	0.00%
KU-131600-EWB 1 Misc Power Plant E	1.52%	1.52%	0.00%
KU-131600-EWB 2 Misc Power Plant E	0.06%	0.06%	0.00%
KU-131600-EWB 3 Misc Power Plant E	3.36%	2.89%	-0.47%
KU-131600-GH 1 Misc Power Plant Eq	1.06%	1.01%	-0.05%
KU-131600-GH 1SC Misc Power Plant	0.90%	0.88%	-0.02%
KU-131600-GH 2 Misc Power Plant Eq	0.89%	0.87%	-0.02%
KU-131600-GH 3 Misc Power Plant Eq	2.17%	2.28%	0.11%
KU-131600-GH 3 Misc PwrPlt ECR 2011	2.17%	2.28%	0.11%
KU-131600-GH 4 Misc Power Plant Eq	3.53%	3.64%	0.11%
KU-131600-GR 1&2 Misc Power Plant	0.00%	0.00%	0.00%
KU-131600-GR 3 Misc Power Plant Eq	0.00%	0.00%	0.00%
KU-131600-GR 4 Misc Power Plant Eq	0.00%	0.00%	0.00%
KU-131600-PI 1-2 Misc Power Plant E	0.00%	0.00%	0.00%
KU-131600-PI 3 Misc Power Plant Eq	0.00%	0.00%	0.00%
KU-131600-SL Misc Power Plant Equi	3.46%	3.46%	0.00%
KU-131600-TC 2 Misc Power Plant Equ	2.26%	2.26%	0.00%
KU-131600-TY 1&2 Misc Power Plant	0.00%	0.00%	0.00%
KU-131600-TY 3 Misc Power Plant Eq	0.00%	0.00%	0.00%
KU-133010-DD Land Rights	0.00%	0.00%	0.00%
KU-133100-DD Structures and Improv	2.48%	2.48%	0.00%
KU-133200-DD Reservoirs, Dams, and	2.61%	2.61%	0.00%
KU-133300-DD Water Wheels, Turbine	3.86%	3.86%	0.00%
KU-133400-DD Accessory Electric Eq	3.81%	3.81%	0.00%
KU-133400-L7 Accessory Electric Eq	0.00%	0.00%	0.00%
KU-133500-DD Misc Power Plant Equi	3.76%	3.76%	0.00%
KU-133500-L7 Misc Power Plant Equi	0.00%	0.00%	0.00%
KU-133600-DD Roads, Railroads, and	3.33%	3.33%	0.00%
KU-134020-EWB 8 Land	0.00%	0.00%	0.00%
KU-134020-EWB Solar Facility Land	0.00%	0.00%	0.00%
KU-134020-Land	0.00%	0.00%	0.00%

KU-134100-CR 7 Structures and Impr	3.03%	3.03%	0.00%
KU-134100-EWB 10 Structures and Im	2.92%	2.92%	0.00%
KU-134100-EWB 11 Structures and Im	4.32%	4.32%	0.00%
KU-134100-EWB 5 Structures and Im	3.94%	3.94%	0.00%
KU-134100-EWB 6 Structures and Imp	4.34%	4.34%	0.00%
KU-134100-EWB 7 Structures and Imp	4.33%	4.33%	0.00%
KU-134100-EWB 8 Structures and Imp	3.97%	3.97%	0.00%
KU-134100-EWB 9 Structures and Imp	2.76%	2.76%	0.00%
KU-134100-EWB Solar Struc and Imp	4.24%	4.24%	0.00%
KU-134100-HA 1,2,&3 Structures and	19.17%	19.17%	0.00%
KU-134100-PR 13 Structures and Imp	4.16%	4.16%	0.00%
KU-134100-TC 10 Structures and Imp	3.79%	3.79%	0.00%
KU-134100-TC 5 Structures and Impr	3.87%	3.87%	0.00%
KU-134100-TC 6 Structures and Impr	3.86%	3.86%	0.00%
KU-134100-TC 7 Structures and Impr	3.78%	3.78%	0.00%
KU-134100-TC 8 Structures and Impr	3.78%	3.78%	0.00%
KU-134100-TC 9 Structures and Impr	3.79%	3.79%	0.00%
KU-134200-CR 7 Fuel Holders, Produ	3.10%	3.10%	0.00%
KU-134200-EWB 10 Fuel Holders, Pro	5.43%	5.43%	0.00%
KU-134200-EWB 11 Fuel Holders, Pro	7.39%	7.39%	0.00%
KU-134200-EWB 5 Fuel Holders, Prod	5.00%	5.00%	0.00%
KU-134200-EWB 6 Fuel Holders, Prod	6.96%	6.96%	0.00%
KU-134200-EWB 7 Fuel Holders, Prod	6.99%	6.99%	0.00%
KU-134200-EWB 8 Fuel Holders, Prod	6.53%	6.53%	0.00%
KU-134200-EWB 9 Fuel Holders, Prod	4.65%	4.65%	0.00%
KU-134200-HA 1,2,&3 Fuel Holders,	15.74%	15.74%	0.00%
KU-134200-PR 13 Fuel Holders, Prod	3.89%	3.89%	0.00%
KU-134200-TC 10 Fuel Holders, Prod	3.85%	3.85%	0.00%
KU-134200-TC 5 Fuel Holders, Produ	3.90%	3.90%	0.00%
KU-134200-TC 6 Fuel Holders, Produ	3.90%	3.90%	0.00%
KU-134200-TC 7 Fuel Holders, Produ	3.82%	3.82%	0.00%
KU-134200-TC 8 Fuel Holders, Produ	3.82%	3.82%	0.00%
KU-134200-TC 9 Fuel Holders, Produ	3.83%	3.83%	0.00%
KU-134201-AROP EWB 9 Turbogenerator	0.00%	0.00%	0.00%
KU-134300-Cane Run 7 Prime Movers	3.57%	3.57%	0.00%
KU-134300-EWB 10 Prime Movers	4.94%	4.94%	0.00%
KU-134300-EWB 11 Prime Movers	4.82%	4.82%	0.00%
KU-134300-EWB 5 Prime Movers	4.41%	4.41%	0.00%
KU-134300-EWB 6 Prime Movers	5.42%	5.42%	0.00%
KU-134300-EWB 7 Prime Movers	5.28%	5.28%	0.00%
KU-134300-EWB 8 Prime Movers	5.81%	5.81%	0.00%
KU-134300-EWB 9 Prime Movers	4.74%	4.74%	0.00%

KU-134300-Green River CC GT	0.00%	0.00%	0.00%
KU-134300-PR 13 Prime Movers	5.53%	5.53%	0.00%
KU-134300-TC 10 Prime Movers	4.49%	4.49%	0.00%
KU-134300-TC 5 Prime Movers	4.58%	4.58%	0.00%
KU-134300-TC 6 Prime Movers	4.50%	4.50%	0.00%
KU-134300-TC 7 Prime Movers	4.52%	4.52%	0.00%
KU-134300-TC 8 Prime Movers	4.57%	4.57%	0.00%
KU-134300-TC 9 Prime Movers	4.48%	4.48%	0.00%
KU-134400-CR 7 Generators	2.89%	2.89%	0.00%
KU-134400-EWB 10 Generators	2.94%	2.94%	0.00%
KU-134400-EWB 11 Generators	5.55%	5.55%	0.00%
KU-134400-EWB 5 Generators	3.98%	3.98%	0.00%
KU-134400-EWB 6 Generators	4.02%	4.02%	0.00%
KU-134400-EWB 7 Generators	4.08%	4.08%	0.00%
KU-134400-EWB 8 Generators	4.04%	4.04%	0.00%
KU-134400-EWB 9 Generators	2.77%	2.77%	0.00%
KU-134400-EWB Solar Generators	4.61%	4.61%	0.00%
KU-134400-HA 1,2,&3 Generators	5.37%	5.37%	0.00%
KU-134400-PR 13 Generators	4.21%	4.21%	0.00%
KU-134400-TC 10 Generators	3.76%	3.76%	0.00%
KU-134400-TC 5 Generators	3.85%	3.85%	0.00%
KU-134400-TC 6 Generators	3.85%	3.85%	0.00%
KU-134400-TC 7 Generators	3.75%	3.75%	0.00%
KU-134400-TC 8 Generators	3.75%	3.75%	0.00%
KU-134400-TC 9 Generators	3.76%	3.76%	0.00%
KU-134500-CR 7 Accessory Electric	2.96%	2.96%	0.00%
KU-134500-EWB 10 Accessory Electri	3.77%	3.77%	0.00%
KU-134500-EWB 11 Accessory Electri	4.92%	4.92%	0.00%
KU-134500-EWB 5 Accessory Electric	4.23%	4.23%	0.00%
KU-134500-EWB 6 Accessory Electric	4.44%	4.44%	0.00%
KU-134500-EWB 7 Accessory Electric	4.45%	4.45%	0.00%
KU-134500-EWB 8 Accessory Electric	5.84%	5.84%	0.00%
KU-134500-EWB 9 Accessory Electric	3.64%	3.64%	0.00%
KU-134500-EWB Solar Accessory Elec	4.36%	4.36%	0.00%
KU-134500-HA 1,2,&3 Accessory Elec	22.16%	22.16%	0.00%
KU-134500-PR 13 Accessory Electric	4.01%	4.01%	0.00%
KU-134500-TC 10 Acessory Electric	4.04%	4.04%	0.00%
KU-134500-TC 5 Accessory Electric	4.18%	4.18%	0.00%
KU-134500-TC 6 Accessory Electric	4.25%	4.25%	0.00%
KU-134500-TC 7 Accessory Electric	4.13%	4.13%	0.00%
KU-134500-TC 8 Accessory Electric	3.79%	3.79%	0.00%
KU-134500-TC 9 Accessory Electric	3.91%	3.91%	0.00%

KU-134501-AROP EWB 10 Acc Electri	0.00%	0.00%	0.00%
KU-134501-AROP EWB 11 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP EWB 5 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP EWB 6 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP EWB 7 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP EWB 8 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP EWB 9 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP TC 7 Acc Electric	0.00%	0.00%	0.00%
KU-134501-AROP TC 8 Acc Electric	0.00%	0.00%	0.00%
KU-134600-CR 7 Misc. Power Plant E	3.32%	3.32%	0.00%
KU-134600-EWB 10 Misc Power Plant	3.26%	3.26%	0.00%
KU-134600-EWB 11 Misc Power Plant	5.22%	5.22%	0.00%
KU-134600-EWB 5 Misc Power Plant E	4.01%	4.01%	0.00%
KU-134600-EWB 6 Misc Power Plant E	6.22%	6.22%	0.00%
KU-134600-EWB 7 Misc Power Plant E	6.24%	6.24%	0.00%
KU-134600-EWB 8 Misc Power Plant E	4.98%	4.98%	0.00%
KU-134600-EWB 9 Misc Power Plant E	3.31%	3.31%	0.00%
KU-134600-EWB Solar Misc Power Plt	4.25%	4.25%	0.00%
KU-134600-HA 1,2,&3 Misc Power Pla	17.75%	17.75%	0.00%
KU-134600-PR 13 Misc Power Plant E	3.93%	3.93%	0.00%
KU-134600-TC 10 Misc Power Plant E	4.61%	4.61%	0.00%
KU-134600-TC 5 Misc. Power Plant E	4.04%	4.04%	0.00%
KU-134600-TC 6 Misc. Power Plant E	0.00%	0.00%	0.00%
KU-134600-TC 7 Misc. Power Plant E	3.89%	3.89%	0.00%
KU-134600-TC 8 Misc. Power Plant E	3.89%	3.89%	0.00%
KU-134600-TC 9 Misc. Power Plant E	3.91%	3.91%	0.00%
KU-135010- KY Land Rights	0.86%	0.86%	0.00%
KU-135010- TN Land Rights	0.86%	0.86%	0.00%
KU-135010- VA Land Rights	0.86%	0.86%	0.00%
KU-135010-Licensed Project Land Ri	0.86%	0.86%	0.00%
KU-135020- KY Land	0.00%	0.00%	0.00%
KU-135020- VA Land	0.00%	0.00%	0.00%
KU-135210- KY Licensed Proj Str & I	1.66%	1.66%	0.00%
KU-135210- KY Struc & Imprv-Non Sys	1.66%	1.66%	0.00%
KU-135210- KY Struc NonSys Dix Ctrl	1.66%	1.66%	0.00%
KU-135210- VA Struc & Imprv-Non Sys	1.66%	1.66%	0.00%
KU-135220-Struct & Improve-System	1.83%	1.83%	0.00%
KU-135310- KY Licensed Proj Sta Eq-	1.90%	1.90%	0.00%
KU-135310- KY Station Equip -Non Sy	1.90%	1.90%	0.00%
KU-135310- VA Station Equip -Non Sy	1.90%	1.90%	0.00%
KU-135311-AROP Station Equip Non S	1.67%	1.67%	0.00%
KU-135320-Station Equipment-System	0.00%	0.00%	0.00%

KU-135400- KY Towers Fix	1.69%	1.69%	0.00%
KU-135400- KY Towers Fix ECR 2005	1.69%	1.69%	0.00%
KU-135400- VA Towers and Fixtures	1.69%	1.69%	0.00%
KU-135500- KY Licensed Proj Poles a	2.93%	2.93%	0.00%
KU-135500- KY Poles	2.93%	2.93%	0.00%
KU-135500- KY Poles ECR 2005	2.93%	2.93%	0.00%
KU-135500- TN Poles and Fixtures	2.93%	2.93%	0.00%
KU-135500- VA Poles and Fixtures	2.93%	2.93%	0.00%
KU-135600- KY Licensed Proj Ohd Con	2.54%	2.54%	0.00%
KU-135600- TN Overhead Conductors	2.54%	2.54%	0.00%
KU-135600- VA Overhead Conductors	2.54%	2.54%	0.00%
KU-135600-KY OH Cond	2.54%	2.54%	0.00%
KU-135600-KY OH Cond ECR 2005	2.54%	2.54%	0.00%
KU-135700- KY Underground Conduit	1.70%	1.70%	0.00%
KU-135700- VA Underground Conduit	1.70%	1.70%	0.00%
KU-135800- KY Undergrd Conductors a	0.74%	0.74%	0.00%
KU-135800- VA Undergrd Conductors a	0.74%	0.74%	0.00%
KU-136010- KY Land Rights	0.64%	0.64%	0.00%
KU-136010- KY Licensed Proj Land Ri	0.64%	0.64%	0.00%
KU-136010- TN Land Rights	0.64%	0.64%	0.00%
KU-136010- VA Land Rights	0.64%	0.64%	0.00%
KU-136020-KY Land	0.00%	0.00%	0.00%
KU-136020-TN Land	0.00%	0.00%	0.00%
KU-136020-VA Land	0.00%	0.00%	0.00%
KU-136025-VA Land	0.00%	0.00%	0.00%
KU-136100- KY Struct and Improv	2.15%	2.15%	0.00%
KU-136100- TN Struct and Improv	2.15%	2.15%	0.00%
KU-136100- VA Struct and Improv	2.15%	2.15%	0.00%
KU-136200- KY Station Equipment	2.29%	2.29%	0.00%
KU-136200- TN Station Equipment	2.29%	2.29%	0.00%
KU-136200- VA Station Equipment	2.29%	2.29%	0.00%
KU-136400-KY Ghent Transpt ECR 2009	2.67%	2.67%	0.00%
KU-136400-KY Licensed Project Pole	2.67%	2.67%	0.00%
KU-136400-KY Poles, Towers, and Fix	2.67%	2.67%	0.00%
KU-136400-TN Poles, Towers, and Fix	2.67%	2.67%	0.00%
KU-136400-VA Poles, Towers, and Fix	2.67%	2.67%	0.00%
KU-136500- KY Licensed Proj Ohd Con	2.47%	2.47%	0.00%
KU-136500- KY Overhead Conductor	2.47%	2.47%	0.00%
KU-136500- TN Overhead Conductor	2.47%	2.47%	0.00%
KU-136500- VA Overhead Conductor	2.47%	2.47%	0.00%
KU-136500-KY Ghent Transpt ECR 2009	2.47%	2.47%	0.00%
KU-136600- KY Underground Conduit	2.32%	2.32%	0.00%

KU-136600- TN Underground Conduit	2.32%	2.32%	0.00%
KU-136600- VA Underground Conduit	2.32%	2.32%	0.00%
KU-136600-KY Ghent Transpt ECR 2009	2.32%	2.32%	0.00%
KU-136700- KY Undergrnd Conductors	2.43%	2.43%	0.00%
KU-136700- TN Undergrnd Conductors	2.43%	2.43%	0.00%
KU-136700- VA Undergrnd Conductors	2.43%	2.43%	0.00%
KU-136700-KY Ghent Transpt ECR 2009	2.43%	2.43%	0.00%
KU-136800- KY Line Transformers	1.79%	1.79%	0.00%
KU-136800- TN Line Transformers	1.79%	1.79%	0.00%
KU-136800- VA Line Transformers	1.79%	1.79%	0.00%
KU-136900- KY Services	1.63%	1.63%	0.00%
KU-136900- TN Services	1.63%	1.63%	0.00%
KU-136900- VA Services	1.63%	1.63%	0.00%
KU-137000- KY Meters	3.51%	3.51%	0.00%
KU-137000- TN Meters	3.51%	3.51%	0.00%
KU-137000- VA Meters	3.51%	3.51%	0.00%
KU-137001- KY DSM Meters	6.85%	6.85%	0.00%
KU-137002- KY Meter Asset Management	6.85%	6.85%	0.00%
KU-137002- VA Meter Asset Management	6.85%	6.85%	0.00%
KU-137020- KY Meters - CT and PT	4.29%	4.29%	0.00%
KU-137020- TN Meters - CT and PT	4.29%	4.29%	0.00%
KU-137020- VA Meters - CT and PT	4.29%	4.29%	0.00%
KU-137100- KY Install on Customers	0.53%	0.53%	0.00%
KU-137100- TN Install on Customers	0.53%	0.53%	0.00%
KU-137100- VA Install on Customers	0.53%	0.53%	0.00%
KU-137101- KY Install Charging Sta	10.00%	10.00%	0.00%
KU-137300- KY Str Lighting and Sign	4.00%	4.00%	0.00%
KU-137300- VA Str Lighting and Sign	4.00%	4.00%	0.00%
KU-138920- KY Land	0.00%	0.00%	0.00%
KU-138920- VA Land	0.00%	0.00%	0.00%
KU-139010- KY Structures & Improv	2.43%	2.43%	0.00%
KU-139010- VA Structures & Improv	2.43%	2.43%	0.00%
KU-139010-KY Stru Pinevll Joint Own	2.43%	2.43%	0.00%
KU-139010-KY Struc Morganfield Offi	2.43%	2.43%	0.00%
KU-139010-KY Struc One Quality Bldg	2.43%	2.43%	0.00%
KU-139010-Pinevlle Storerm Owned	2.43%	2.43%	0.00%
KU-139020- VA Pennington Gap Office	1.43%	1.43%	0.00%
KU-139020- VA Wise Office	1.43%	1.43%	0.00%
KU-139020-Carlisle Office	1.43%	1.43%	0.00%
KU-139020-Coeburn Office	1.43%	1.43%	0.00%
KU-139020-Columbia Office	1.43%	1.43%	0.00%
KU-139020-Corbin Office	1.43%	1.43%	0.00%

KU-139020-Earlington Pole Yard	1.43%	1.43%	0.00%
KU-139020-Eddyville Office	1.43%	1.43%	0.00%
KU-139020-Ewing Office	1.43%	1.43%	0.00%
KU-139020-Flemingsburg Storeroom	1.43%	1.43%	0.00%
KU-139020-Henderson Office	1.43%	1.43%	0.00%
KU-139020-Lexington Northside Offic	1.43%	1.43%	0.00%
KU-139020-Liberty Office	1.43%	1.43%	0.00%
KU-139020-Livermore Storeroom	1.43%	1.43%	0.00%
KU-139020-London Office	1.43%	1.43%	0.00%
KU-139020-Manchester Office	1.43%	1.43%	0.00%
KU-139020-Morehead Storeroom	1.43%	1.43%	0.00%
KU-139020-Richmond Office	1.43%	1.43%	0.00%
KU-139020-Somerset Pole Yard	1.43%	1.43%	0.00%
KU-139020-St Paul Office	1.43%	1.43%	0.00%
KU-139020-Tates Creek Office	1.43%	1.43%	0.00%
KU-139020-Taylorsville Office	1.43%	1.43%	0.00%
KU-139020-Versailles Storeroom	1.43%	1.43%	0.00%
KU-139020-Whitley City Office	1.43%	1.43%	0.00%
KU-139110- KY Office Equipment	4.36%	4.36%	0.00%
KU-139110- VA Office Equipment	4.36%	4.36%	0.00%
KU-139120-KY Non PC Computer Equip	11.69%	11.69%	0.00%
KU-139120-VA Non PC Computer Equip	11.69%	11.69%	0.00%
KU-139130-Cash Processing Equipmen	0.00%	0.00%	0.00%
KU-139131-Personal Computers	25.02%	25.02%	0.00%
KU-139200- KY - Ghent 4 ECR 2009	1.97%	1.97%	0.00%
KU-139300- KY Stores Equipment	4.40%	4.40%	0.00%
KU-139300- VA Stores Equipment	4.40%	4.40%	0.00%
KU-139400- KY Tools, Shop, Garage	4.02%	4.02%	0.00%
KU-139400- VA Tools, Shop, Garage	4.02%	4.02%	0.00%
KU-139500-KY Laboratory Equipment	0.00%	0.00%	0.00%
KU-139500-VA Laboratory Equipment	0.00%	0.00%	0.00%
KU-139600-KY Power Op Equip	0.00%	0.00%	0.00%
KU-139600-VA Power Op Equip	0.00%	0.00%	0.00%
KU-139700-KY DSM Communication	4.90%	4.90%	0.00%
KU-139700-KY Microwave,Fiber,Other	4.90%	4.90%	0.00%
KU-139700-VA Microwave,Fiber,Other	4.90%	4.90%	0.00%
KU-139710- KY Radios and Telephone	10.84%	10.84%	0.00%
KU-139710- VA Radios and Telephone	10.84%	10.84%	0.00%
KU-139720- DSM Equipment	14.08%	14.08%	0.00%
KU-139800- KY Miscellaneous Equip	0.00%	0.00%	0.00%
KU-139800- VA Miscellaneous Equip	0.00%	0.00%	0.00%
KU-312104-Nonutility Prop - Misc L	0.00%	0.00%	0.00%

KU-312105-Nonutility Prop-Misc Str	0.00%	0.00%	0.00%
KU-312106-Nonutility-Misc Land Rig	0.00%	0.00%	0.00%
KU-139620-KY Power Op Equip - Other	5.65%	5.65%	0.00%
KU-134020-Simpson Solar Share Land	0.00%	0.00%	0.00%
KU-134100-Simp Solar A1 Struc & Imp	4.24%	4.24%	0.00%
KU-134400-Simp Solar A1 Generators	4.61%	4.61%	0.00%
KU-134500-Simp Solar A1 Access Elec	4.36%	4.36%	0.00%
KU-134600-Simp Solar A1 Misc Pwr Pl	4.25%	4.25%	0.00%

KENTUCKY UTILITIES

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DEPRECIABLE PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	TRIMBLE COUNTY UNIT 2	105-R2.5	*	(13)	96,307,268.16	27,875,957	80,951,256	1,740,732	1.81	46.5
	TRIMBLE COUNTY UNIT 2 SCRUBBER	105-R2.5	*	(13)	5,556,451.46	3,229,484	3,049,306	67,265	1.21	45.3
	SYSTEM LABORATORY	105-R2.5	*	0	1,117,119.13	736,160	380,959	17,187	1.54	22.2
	BROWN UNIT 1	105-R2.5	*	(6)	4,677,142.79	4,955,316	2,455	2,099	0.04	1.2
	BROWN UNIT 2	105-R2.5	*	(6)	2,309,727.39	2,431,335	16,976	14,510	0.63	1.2
	BROWN UNIT 3	105-R2.5	*	(6)	28,754,404.33	14,706,856	15,772,813	778,571	2.71	20.3
	BROWN UNIT 1, 2 AND 3 SCRUBBER	105-R2.5	*	(6)	45,382,543.88	12,264,813	35,840,684	1,762,943	3.88	20.3
	GHENT UNIT 1 SCRUBBER	105-R2.5	*	(10)	8,397,192.12	7,509,513	1,727,398	89,871	1.07	19.2
	GHENT UNIT 1	105-R2.5	*	(10)	21,345,248.67	17,200,351	6,279,423	326,200	1.53	19.3
	GHENT UNIT 2	105-R2.5	*	(10)	16,653,049.60	14,451,749	3,866,606	202,931	1.22	19.1
	GHENT UNIT 3	105-R2.5	*	(10)	51,457,056.74	34,353,891	22,248,871	1,160,210	2.25	19.2
	GHENT UNIT 4	105-R2.5	*	(10)	43,271,160.71	16,660,841	30,937,436	1,529,264	3.53	20.2
	GHENT UNIT 2 SCRUBBER	105-R2.5	*	(10)	15,816,339.70	14,084,948	3,313,026	172,643	1.09	19.2
	GHENT UNIT 4 SCRUBBER	105-R2.5	*	(10)	36,901.04	0	40,591	1,995	5.41	20.3
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				341,081,605.72	170,461,214	204,427,800	7,866,421	2.31	26.0
311.20	STRUCTURES AND IMPROVEMENTS - RETIRED PLANT									
	TYRONE UNIT 3	105-R2.5	*	(10)	1,821,179.50	2,003,297	0	0	-	-
	TYRONE UNITS 1 AND 2	105-R2.5	*	(10)	630,860.03	693,946	0	0	-	-
	GREEN RIVER UNIT 3	105-R2.5	*	(10)	2,756,302.50	3,031,933	0	0	-	-
	GREEN RIVER UNIT 4	105-R2.5	*	(10)	5,631,448.40	6,194,593	0	0	-	-
	GREEN RIVER UNITS 1 AND 2	105-R2.5	*	(10)	1,756,471.53	1,932,119	0	0	-	-
	PINEVILLE UNIT 3	105-R2.5	*	(10)	182,442.49	200,687	0	0	-	-
	TOTAL ACCOUNT 311.2 - STRUCTURES AND IMPROVEMENTS - RETIRED PLANT				12,778,704.45	14,056,575	0	0	-	-
312.00	BOILER PLANT EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	70-R1.5	*	(13)	554,266,452.52	110,556,316	515,764,775	12,038,282	2.17	42.8
	TRIMBLE COUNTY UNIT 2 SCRUBBER	70-R1.5	*	(13)	72,953,390.63	21,555,951	60,881,380	1,429,927	1.96	42.6
	BROWN UNIT 1	70-R1.5	*	(6)	38,556,575.43	39,433,716	1,436,254	1,238,148	3.21	1.2
	BROWN UNIT 2	70-R1.5	*	(6)	42,204,805.56	43,229,373	1,507,721	1,299,759	3.08	1.2
	BROWN UNIT 3	70-R1.5	*	(6)	442,651,264.76	80,166,586	389,043,755	19,753,757	4.46	19.7
	BROWN UNIT 1, 2 AND 3 SCRUBBER	70-R1.5	*	(6)	335,178,567.22	75,103,808	280,185,473	14,171,418	4.23	19.8
	GHENT UNIT 1 SCRUBBER	70-R1.5	*	(10)	139,576,135.58	57,639,685	95,894,064	5,098,612	3.65	18.8
	GHENT UNIT 1	70-R1.5	*	(10)	355,931,120.22	110,114,714	281,409,518	15,014,528	4.22	18.7
	GHENT UNIT 2	70-R1.5	*	(10)	277,188,781.51	74,139,461	230,768,199	12,333,219	4.45	18.7
	GHENT UNIT 3	70-R1.5	*	(10)	433,488,085.02	181,912,764	294,924,130	15,822,484	3.65	18.6
	GHENT UNIT 4	70-R1.5	*	(10)	751,196,369.80	168,106,676	658,209,331	33,460,201	4.45	19.7
	GHENT UNIT 2 SCRUBBER	70-R1.5	*	(10)	70,125,568.12	62,367,365	14,770,760	788,295	1.12	18.7
	GHENT UNIT 3 SCRUBBER	70-R1.5	*	(10)	119,327,931.24	39,524,131	91,736,593	4,892,675	4.10	18.7
	GHENT UNIT 4 SCRUBBER	70-R1.5	*	(10)	254,161,647.89	95,407,708	184,170,105	9,320,031	3.67	19.8
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				3,886,806,695.50	1,159,258,254	3,100,702,058	146,661,336	3.77	21.1
312.10	BOILER PLANT EQUIPMENT - ASH PONDS									
	TRIMBLE COUNTY UNIT 2 ASH POND	100-S4	*	0	9,104,044.87	5,018,153	4,085,892	680,982	7.48	6.0
	BROWN UNIT 1 ASH POND	100-S4	*	0	9,299,115.00	9,298,845	270	90	0.00	3.0
	BROWN UNIT 2 ASH POND	100-S4	*	0	3,909,061.67	2,991,413	917,649	305,883	7.82	3.0
	BROWN UNIT 3 ASH POND	100-S4	*	0	19,802,080.26	5,142,558	14,659,522	4,886,507	24.68	3.0
	GHENT UNIT 1 SCRUBBER ASH POND	100-S4	*	0	39,480.55	39,209	272	91	0.23	3.0
	GHENT UNIT 1 ASH POND	100-S4	*	0	2,100,620.94	2,073,761	26,860	5,372	0.26	5.0
	GHENT UNIT 4 ASH POND	100-S4	*	0	32,692,663.87	14,310,027	18,382,637	4,595,659	14.06	4.0
	GHENT UNIT 2 SCRUBBER ASH POND	100-S4	*	0	1,901,133.18	1,901,133	0	0	-	-
	TYRONE UNIT 3 - ASH POND	100-S4	*	0	575,455.72	575,456	0	0	-	-
	GREEN RIVER UNIT 3 - ASH POND	100-S4	*	0	1,831,840.98	1,831,841	0	0	-	-
	PINEVILLE UNIT 3 - ASH POND	100-S4	*	0	91,265.89	91,266	0	0	-	-
	TOTAL ACCOUNT 312.1 - BOILER PLANT EQUIPMENT - ASH PONDS				81,346,762.93	43,273,662	38,073,102	10,474,584	12.88	3.6

KENTUCKY UTILITIES

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
314.00 TURBOGENERATOR UNITS									
TRIMBLE COUNTY UNIT 2	60-R2	*	(13)	89,986,324.04	21,764,667	79,919,879	1,925,583	2.14	41.5
BROWN UNIT 1	60-R2	*	(6)	11,380,919.20	11,727,960	335,814	287,021	2.52	1.2
BROWN UNIT 2	60-R2	*	(6)	13,703,060.56	14,265,275	259,969	222,196	1.62	1.2
BROWN UNIT 3	60-R2	*	(6)	45,797,249.49	8,377,637	40,167,447	2,093,922	4.57	19.2
GHENT UNIT 1	60-R2	*	(10)	40,327,741.42	22,388,069	21,972,447	1,195,361	2.96	18.4
GHENT UNIT 2	60-R2	*	(10)	33,056,975.75	22,423,578	13,939,095	784,168	2.37	17.8
GHENT UNIT 3	60-R2	*	(10)	43,859,372.17	30,697,120	17,548,189	981,509	2.24	17.9
GHENT UNIT 4	60-R2	*	(10)	59,231,536.72	34,540,570	30,614,120	1,625,352	2.74	18.8
TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				337,343,179.35	166,184,876	204,756,960	9,115,112	2.70	22.5
315.00 ACCESSORY ELECTRIC EQUIPMENT									
TRIMBLE COUNTY UNIT 2	70-R4	*	(13)	45,619,554.81	9,925,988	41,624,109	907,424	1.99	45.9
TRIMBLE COUNTY UNIT 2 SCRUBBER	70-R4	*	(13)	1,415,469.10	793,978	805,502	20,168	1.42	39.9
BROWN UNIT 1	70-R4	*	(6)	4,321,324.05	4,517,823	62,780	53,659	1.24	1.2
BROWN UNIT 2	70-R4	*	(6)	2,416,429.81	2,504,751	56,665	48,431	2.00	1.2
BROWN UNIT 3	70-R4	*	(6)	15,435,528.73	6,347,369	10,014,291	493,472	3.20	20.3
BROWN UNIT 1, 2 AND 3 SCRUBBER	70-R4	*	(6)	29,324,457.10	6,736,824	24,347,101	1,189,403	4.06	20.5
GHENT UNIT 1 SCRUBBER	70-R4	*	(10)	12,223,379.51	5,766,682	7,679,035	394,775	3.23	19.5
GHENT UNIT 1	70-R4	*	(10)	12,336,881.42	8,571,504	4,999,066	261,566	2.12	19.1
GHENT UNIT 2	70-R4	*	(10)	14,213,740.74	11,578,763	4,056,352	216,987	1.53	18.7
GHENT UNIT 3	70-R4	*	(10)	33,564,209.82	25,293,521	11,627,110	618,293	1.84	18.8
GHENT UNIT 4	70-R4	*	(10)	52,184,797.21	18,816,313	38,586,964	1,907,200	3.65	20.2
GHENT UNIT 2 SCRUBBER	70-R4	*	(10)	951,198.87	266,709	779,610	40,040	4.21	19.5
GHENT UNIT 3 SCRUBBER	70-R4	*	(10)	12,041,998.28	4,433,095	8,813,103	453,299	3.76	19.4
GHENT UNIT 4 SCRUBBER	70-R4	*	(10)	15,148,041.55	3,480,348	13,182,498	643,991	4.25	20.5
TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				251,197,011.00	109,033,668	166,634,186	7,248,708	2.89	23.0
316.00 MISCELLANEOUS PLANT EQUIPMENT									
TRIMBLE COUNTY UNIT 2	75-R1.5	*	(13)	7,002,702.79	1,014,150	6,898,904	158,008	2.26	43.7
SYSTEM LABORATORY	75-R1.5	*	0	3,688,912.98	933,650	2,755,263	127,717	3.46	21.6
BROWN UNIT 1	75-R1.5	*	(6)	389,684.21	406,185	6,880	5,931	1.52	1.2
BROWN UNIT 2	75-R1.5	*	(6)	123,107.10	130,414	80	69	0.06	1.2
BROWN UNIT 3	75-R1.5	*	(6)	6,483,855.33	3,197,454	3,675,433	187,194	2.89	19.6
GHENT UNIT 1 SCRUBBER	75-R1.5	*	(10)	962,012.25	900,830	157,383	8,437	0.88	18.7
GHENT UNIT 1	75-R1.5	*	(10)	1,845,970.85	1,684,463	346,105	18,691	1.01	18.5
GHENT UNIT 2	75-R1.5	*	(10)	1,553,509.99	1,460,824	248,037	13,591	0.87	18.3
GHENT UNIT 3	75-R1.5	*	(10)	4,027,500.01	2,729,825	1,700,425	91,749	2.28	18.5
GHENT UNIT 4	75-R1.5	*	(10)	9,999,060.73	3,857,934	7,141,033	363,611	3.64	19.6
TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT				36,076,316.24	16,315,729	22,929,543	974,998	2.70	23.5
TOTAL STEAM PRODUCTION PLANT				**4,946,630,275.19**	**1,678,583,978**	**3,737,523,649**	**182,341,159**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

KENTUCKY UTILITIES COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 201

		Terminal Retirements			Interim Retirements			Total		Estimated
	Account	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Net Salvage ($)	Total Retirements	Net Salvage (%)
	(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
STEAM PRODUCTION PLANT										
	BROWN GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	78,898,851	(4)	(3,155,954)	2,224,967	(30)	(667,490.24)	(3,823,444)	81,123,818	(6)
312	BOILER PLANT EQUIPMENT	784,558,922	(4)	(31,382,357)	74,032,291	(30)	(22,209,687)	(53,592,044)	858,591,213	(6)
314	TURBOGENERATOR UNITS	64,002,855	(4)	(2,560,114)	6,878,375	(15)	(1,031,756)	(3,591,870)	70,881,229	(6)
315	ACCESSORY ELECTRIC EQUIPMENT	50,029,587	(4)	(2,001,183)	1,468,153	(15)	(220,223)	(2,221,406)	51,497,740	(6)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	6,314,569	(4)	(252,583)	682,078	(2)	(13,642)	(266,224)	6,996,647	(6)
	TOTAL BROWN GENERATING STATION	*983,804,784*		*(39,352,191)*	*85,285,863*		*(24,142,798)*	*(63,494,989)*	*1,069,090,647*	*(6)*
	GHENT GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	149,496,462	(8)	(11,959,717)	7,480,487	(30)	(2,244,146)	(14,203,863)	156,976,949	(10)
312	BOILER PLANT EQUIPMENT	2,144,877,998	(8)	(171,590,240)	256,117,641	(30)	(76,835,292)	(248,425,532)	2,400,995,639	(10)
314	TURBOGENERATOR UNITS	139,789,729	(8)	(11,183,178)	36,685,897	(15)	(5,502,884)	(16,686,063)	176,475,626	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	142,131,535	(8)	(11,370,523)	10,532,713	(15)	(1,579,907)	(12,950,430)	152,664,247	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	16,163,251	(8)	(1,293,060)	2,224,803	(2)	(44,496)	(1,337,556)	18,388,054	(10)
	TOTAL GHENT GENERATING STATION	*2,592,458,975*		*(207,396,718)*	*313,041,540*		*(86,206,726)*	*(293,603,444)*	*2,905,500,515*	*(10)*
	GREEN RIVER GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	8,423,626	(10)	(842,363)	-	(30)	-	(842,363)	8,423,626	(10)
312	BOILER PLANT EQUIPMENT	470,724	(10)	(47,072)	-	(30)	-	(47,072)	470,724	(10)
314	TURBOGENERATOR UNITS	164,486	(10)	(16,449)	-	(15)	-	(16,449)	164,486	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	646,150	(10)	(64,615)	-	(15)	-	(64,615)	646,150	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	439,237	(10)	(43,924)	-	(2)	-	(43,924)	439,237	(10)
	TOTAL GREEN RIVER GENERATING STATION	*10,144,222*		*(1,014,422)*	-		-	*(1,014,422)*	*10,144,222*	*(10)*
	PINEVILLE GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	37,240	(10)	(3,724)	-	(30)	-	(3,724)	37,240	(10)
312	BOILER PLANT EQUIPMENT	145,203	(10)	(14,520)	-	(30)	-	(14,520)	145,203	(10)
314	TURBOGENERATOR UNITS	-	(10)	0	-	(15)	-	-	-	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	-	(10)	0	-	(15)	-	-	-	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	-	(10)	0	-	(2)	-	-	-	(10)
	TOTAL PINEVILLE GENERATING STATION	*182,442*		*(18,244)*	-		-	*(18,244)*	*182,442*	*(10)*
	SYSTEM LAB									
311	STRUCTURES AND IMPROVEMENTS	1,064,516	0	0	52,603	(30)	(15,781)	(15,781)	1,117,119	0
312	BOILER PLANT EQUIPMENT	-	0	0	-	(30)	-	-	-	0
314	TURBOGENERATOR UNITS	-	0	0	-	(15)	-	-	-	0
315	ACCESSORY ELECTRIC EQUIPMENT	-	0	0	-	(15)	-	-	-	0
316	MISCELLANEOUS POWER PLANT EQUIPMENT	3,387,675	0	0	301,238	(2)	(6,025)	(6,025)	3,688,913	0
	TOTAL SYSTEM LAB	*4,452,191*		-	*353,841*		*(21,806)*	*(21,806)*	*4,806,032*	*0*
STEAM PRODUCTION PLANT (CONT.)										
	TYRONE GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	2,214,639	(10)	(221,464)	-	(30)	-	(221,464)	2,214,639	(10)
312	BOILER PLANT EQUIPMENT	127,100	(10)	(12,710)	-	(30)	-	(12,710)	127,100	(10)
314	TURBOGENERATOR UNITS	-	(10)	0	-	(15)	-	-	-	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	24,267	(10)	(2,427)	-	(15)	-	(2,427)	24,267	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	86,033	(10)	(8,603)	-	(2)	-	(8,603)	86,033	(10)
	TOTAL TYRONE GENERATING STATION	*2,452,040*		*(245,204)*	-		-	*(245,204)*	*2,452,040*	*(10)*
	TRIMBLE COUNTY									
311	STRUCTURES AND IMPROVEMENTS	88,236,897	(7)	(6,176,583)	13,626,823	(30)	(4,088,047)	(10,264,630)	101,863,720	(13)
312	BOILER PLANT EQUIPMENT	417,299,547	(7)	(29,210,968)	209,920,296	(30)	(62,976,089)	(92,187,057)	627,219,843	(13)
314	TURBOGENERATOR UNITS	53,597,327	(7)	(3,751,813)	36,388,997	(15)	(5,458,350)	(9,210,162)	89,986,324	(13)
315	ACCESSORY ELECTRIC EQUIPMENT	35,302,438	(7)	(2,471,171)	11,732,586	(15)	(1,759,888)	(4,231,059)	47,035,024	(13)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	5,267,283	(7)	(368,710)	1,735,420	(2)	(34,708)	(403,418)	7,002,703	(13)
	TOTAL TRIMBLE COUNTY	*599,703,492*		*(41,979,244)*	*273,404,122*		*(74,317,082)*	*(116,296,326)*	*873,107,614*	*(13)*
TOTAL STEAM PRODUCTION PLANT		**4,193,198,146**		**(290,006,024)**	**672,085,366**		**(184,688,411)**	**(474,694,435)**	**4,865,283,512**	

Exhibit JTS-11

LG&E's Response to US DOD-2
Question No. 8

Witness: James T. Selecky

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Supplemental Request for Information of the U. S. Department of Defense
Dated December 13, 2018

Case No. 2018-00295

Question No. 8

Responding Witness: Daniel K. Arbough / John J. Spanos

Q-8. Please refer to page 799 of Attachment 1 to Response to US DOD-1 Question No. 7.

a. Please explain why the Company did not extend the lifespan of Mill Creek 1 and 2, Brown 3, and Ghent 1 and 2 by three years as Mr. Spanos had intended.

b. Please explain why Mr. Spanos thought the lives of these units should be extended by three years.

c. Please provide the impact on depreciation rates and test year depreciation expense for these units by extending the lives by three years.

d. Please provide the remaining life for each FERC account for each unit if the life was extended by three years such that Table 1 of the depreciation study (Exhibit JJS-LG&E-1) can be updated.

e. Please provide the interim retirements for each plant FERC account for each plant if the life was extended by three years such that Table 2 of the Depreciation Study (Exhibit JJS-LG&E-1) can be updated.

A-8.

a. The request misstates the email referenced therein. The email (page 799 of Attachment 1) discussion relates to a possible alternative to some of the steam units. Based on discussions with Company personnel it was determined this alternative was not consistent with the outlook of the units.

b. Mr. Spanos did not think the lives of these units should be extended by three years. Page 799 was an email discussing the possible alternative of extending the currently approved life span by three years.

c. See attached which sets forth the results for extending the designated units by three years. This calculation reduces depreciation expense for steam plant by $2,478,836 as compared to the depreciation study filed.

d. See attached for remaining lives by unit and account with the changed probable retirement dates for some units.

e. See attached for interim retirements for each account and unit for the facilities with a changed probable retirement date of three years.

	Filed	Rates Using 3 plus Years	Variance
Depreciation Expense	221,495,054.46	219,016,218.39	(2,478,836.07)

DESCRIPTION	Filed	Rates Using 3 plus Years	Variance
LGE-131100-Cane Run Unit 1 Structur	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 2 Structur	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 3 Structur	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 4 SO2-Stru	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 4 Structur	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 5 SO2-Stru	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 5 Structur	0.00%	0.00%	0.00%
LGE-131100-Cane Run Unit 6 SO2-Stru	0.00%	0.00%	0.00%
LGE-131100-CR Unit 6 Struc	0.00%	0.00%	0.00%
LGE-131100-CR Unit 6 Struc ECR 2005	0.00%	0.00%	0.00%
LGE-131100-Distribution Dr ECR 2011	2.66%	2.66%	0.00%
LGE-131100-Distribution Drive	2.66%	2.66%	0.00%
LGE-131100-MC Unit 1 Struc ECR 2011	1.76%	1.52%	-0.24%
LGE-131100-MC Unit 2 SO2 ECR 2011	5.61%	4.80%	-0.81%
LGE-131100-MC Unit 2 Struc ECR 2011	2.31%	2.02%	-0.29%
LGE-131100-MC Unit 4 Struc	2.21%	2.25%	0.04%
LGE-131100-MC Unit 4 Struc ECR 2005	2.21%	2.25%	0.04%
LGE-131100-MC Unit 4 Struc ECR 2011	2.21%	2.25%	0.04%
LGE-131100-Mill Creek 3 ECR 2011	1.83%	1.88%	0.05%
LGE-131100-Mill Creek Unit 1 SO2-St	0.00%	0.00%	0.00%
LGE-131100-Mill Creek Unit 1 Struct	1.76%	1.52%	-0.24%
LGE-131100-Mill Creek Unit 2 SO2-St	5.61%	4.80%	-0.81%
LGE-131100-Mill Creek Unit 2 Struct	2.31%	2.02%	-0.29%
LGE-131100-Mill Creek Unit 3 SO2-St	5.26%	5.31%	0.05%
LGE-131100-Mill Creek Unit 3 Struct	1.83%	1.88%	0.05%
LGE-131100-Mill Creek Unit 4 SO2-St	2.80%	2.84%	0.04%
LGE-131100-Mill Creek3 SO2 ECR 2011	5.26%	5.31%	0.05%
LGE-131100-Mill Creek4 SO2 ECR 2011	2.80%	2.84%	0.04%
LGE-131100-TC 1 Future Use - 105	1.77%	0.00%	-1.77%
LGE-131100-TC Unit 1 Struc	1.68%	1.68%	0.00%
LGE-131100-TC Unit 1 Struc ECR 2006	1.68%	1.68%	0.00%
LGE-131100-TC Unit 2 Struc	2.16%	2.16%	0.00%
LGE-131100-TC Unit 2 Struc ECR 2006	2.16%	2.16%	0.00%
LGE-131100-TC Unit 2 Struc ECR 2009	2.16%	2.16%	0.00%

LGE-131100-Trimble Unit 1 SO2-Struc	3.57%	3.57%	0.00%
LGE-131100-Trimble Unit 2 FGD-Struc	2.25%	2.25%	0.00%
LGE-131101-AROP CR 1 Struct & Impr	0.00%	0.00%	0.00%
LGE-131101-AROP CR 6 Struc ECR 2005	0.00%	0.00%	0.00%
LGE-131101-AROP CR 6 Struct & Impr	0.00%	0.00%	0.00%
LGE-131101-AROP MC 1 Struct & Impr	0.00%	0.00%	0.00%
LGE-131101-AROP MC 3 Struct & Impr	0.00%	0.00%	0.00%
LGE-131101-AROP MC 4 Struct & Impr	0.00%	0.00%	0.00%
LGE-131101-AROP TC 1 Struct & Impr	0.00%	0.00%	0.00%
LGE-131101-AROP TC 2 Struc ECR 2009	0.00%	0.00%	0.00%
LGE-131110-CR 6 Capital Leased Equi	6.99%	0.00%	-6.99%
LGE-131110-MC 4 Capital Leased Equi	1.65%	0.00%	-1.65%
LGE-131200-Cane Run Rail Cars - Boi	0.00%	0.00%	0.00%
LGE-131200-Cane Run Unit 1 Boiler P	0.00%	0.00%	0.00%
LGE-131200-Cane Run Unit 2 Boiler P	0.00%	0.00%	0.00%
LGE-131200-Cane Run Unit 3 Boiler P	0.00%	0.00%	0.00%
LGE-131200-Cane Run Unit 4 SO2 Boil	0.00%	0.00%	0.00%
LGE-131200-Cane Run Unit 5 SO2 Boil	0.00%	0.00%	0.00%
LGE-131200-CR Unit 4 Boil	0.00%	0.00%	0.00%
LGE-131200-CR Unit 4 Boil ECR 2006	0.00%	0.00%	0.00%
LGE-131200-CR Unit 5 Boil	0.00%	0.00%	0.00%
LGE-131200-CR Unit 5 Boil ECR 2006	0.00%	0.00%	0.00%
LGE-131200-CR Unit 6 Boil	0.00%	0.00%	0.00%
LGE-131200-CR Unit 6 Boil ECR 2006	0.00%	0.00%	0.00%
LGE-131200-CR6 SO2 Boil	0.00%	0.00%	0.00%
LGE-131200-CR6 SO2 Boil ECR 2005	0.00%	0.00%	0.00%
LGE-131200-MC Offsite Rail Cars	0.36%	0.00%	-0.36%
LGE-131200-MC Unit 1 Boil	6.15%	5.21%	-0.94%
LGE-131200-MC Unit 1 Boil ECR 2006	6.15%	5.21%	-0.94%
LGE-131200-MC Unit 1 Boil ECR 2011	6.15%	5.21%	-0.94%
LGE-131200-MC Unit 1 Boil-Ash Pond	10.94%	10.94%	0.00%
LGE-131200-MC Unit 2 Boil	6.27%	5.41%	-0.86%
LGE-131200-MC Unit 2 Boil ECR 2006	6.27%	5.41%	-0.86%
LGE-131200-MC Unit 2 Boil ECR 2011	6.27%	5.41%	-0.86%
LGE-131200-MC Unit 2 SO2 ECR 2011	6.27%	5.84%	-0.43%
LGE-131200-MC Unit 2 SO2 ECR 2016	6.27%	5.84%	-0.43%
LGE-131200-MC Unit 3 Boil	4.47%	4.52%	0.05%
LGE-131200-MC Unit 3 Boil ECR 2006	4.47%	4.52%	0.05%
LGE-131200-MC Unit 3 Boil ECR 2011	4.47%	4.52%	0.05%
LGE-131200-MC Unit 3 Boil-Ash Pond	21.94%	21.94%	0.00%
LGE-131200-MC Unit 3 SO2 ECR 2011	4.47%	5.59%	1.12%

LGE-131200-MC Unit 3 SO2 ECR 2016	4.47%	5.59%	1.12%
LGE-131200-MC Unit 4 Boil	3.61%	3.66%	0.05%
LGE-131200-MC Unit 4 Boil ECR 2005	3.61%	3.66%	0.05%
LGE-131200-MC Unit 4 Boil ECR 2006	3.61%	3.66%	0.05%
LGE-131200-MC Unit 4 Boil ECR 2011	3.61%	3.66%	0.05%
LGE-131200-MC Unit 4 Boil ECR 2016	3.61%	3.66%	0.05%
LGE-131200-MC4 SO2 Boil	4.47%	4.51%	0.04%
LGE-131200-MC4 SO2 Boil ECR 2005	4.47%	4.51%	0.04%
LGE-131200-MC4 SO2 Boil ECR 2009	4.47%	4.51%	0.04%
LGE-131200-MC4 SO2 Boil ECR 2011	4.47%	4.51%	0.04%
LGE-131200-MC4 SO2 Boil ECR 2016	4.47%	4.51%	0.04%
LGE-131200-Mill Creek Rail Cars Boi	0.36%	0.00%	-0.36%
LGE-131200-Mill Creek Unit 1 SO2 Bo	3.67%	3.14%	-0.53%
LGE-131200-Mill Creek Unit 2 SO2 Bo	6.78%	5.84%	-0.94%
LGE-131200-Mill Creek Unit 3 SO2 Bo	5.54%	5.59%	0.05%
LGE-131200-TC 1 Future Use - 105	2.83%	0.00%	-2.83%
LGE-131200-TC 2 FGD Boil	2.33%	2.33%	0.00%
LGE-131200-TC 2 FGD Boil ECR 2006	2.33%	2.33%	0.00%
LGE-131200-TC Unit 1 Boil	3.02%	3.02%	0.00%
LGE-131200-TC Unit 1 Boil ECR 2006	3.02%	3.02%	0.00%
LGE-131200-TC Unit 1 Boil ECR 2009	3.02%	3.02%	0.00%
LGE-131200-TC Unit 1 Boil ECR 2011	3.02%	3.02%	0.00%
LGE-131200-TC Unit 1 Boil-Ash Pond	10.30%	10.30%	0.00%
LGE-131200-TC Unit 2 Boil	2.39%	2.39%	0.00%
LGE-131200-TC Unit 2 Boil ECR 2006	2.39%	2.39%	0.00%
LGE-131200-TC Unit 2 Boil ECR 2009	2.39%	2.39%	0.00%
LGE-131200-TC Unit 2 Boil ECR 2016	2.39%	2.39%	0.00%
LGE-131200-TC1 SO2 Boil	2.31%	2.31%	0.00%
LGE-131200-TC1 SO2 Boil ECR 2005	2.31%	2.31%	0.00%
LGE-131200-TC1 SO2 Boil ECR 2016	2.31%	2.31%	0.00%
LGE-131200-TC2 Boil ECR 2009-Ash Po	21.96%	21.96%	0.00%
LGE-131201-AROP MC3 Boiler Plt Equp	0.00%	0.00%	0.00%
LGE-131201-AROP MC4 SO2 Boiler Plt	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 1 Turbogen	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 2 Turbogen	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 3 Turbogen	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 4 Turbogen	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 5 SO2 Turb	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 5 Turbogen	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 6 SO2 Turb	0.00%	0.00%	0.00%
LGE-131400-Cane Run Unit 6 Turbogen	0.00%	0.00%	0.00%

LGE-131400-Mill Creek Unit 1Turboge	4.76%	4.04%	-0.72%
LGE-131400-Mill Creek Unit 2 Turbog	4.22%	3.66%	-0.56%
LGE-131400-Mill Creek Unit 3 Turbog	2.63%	2.68%	0.05%
LGE-131400-Mill Creek Unit 4 Turbog	2.88%	2.92%	0.04%
LGE-131400-TC 1 Future Use - 105	2.43%	0.00%	-2.43%
LGE-131400-Trimble Unit 1 Turbogene	2.17%	2.17%	0.00%
LGE-131400-Trimble Unit 2 Turbogene	2.21%	2.21%	0.00%
LGE-131500-Cane Run Unit 1 Accessor	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 2 Accessor	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 3 Acessory	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 4 Accessor	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 4 SO2 Acce	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 5 Acccesso	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 5 SO2 Acce	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 6 Accessor	0.00%	0.00%	0.00%
LGE-131500-Cane Run Unit 6 SO2 Acce	0.00%	0.00%	0.00%
LGE-131500-MC Unit 1 Acc ECR 2011	3.31%	2.82%	-0.49%
LGE-131500-MC Unit 2 Acc ECR 2011	3.77%	3.26%	-0.51%
LGE-131500-MC Unit 2 SO2 ECR 2011	4.97%	4.27%	-0.70%
LGE-131500-MC Unit 3 Acc ECR 2011	2.89%	2.95%	0.06%
LGE-131500-Mill Creek 4 ECR 2011	2.16%	2.20%	0.04%
LGE-131500-Mill Creek Unit 1 Access	3.31%	2.82%	-0.49%
LGE-131500-Mill Creek Unit 1 SO2 Ac	0.07%	0.12%	0.05%
LGE-131500-Mill Creek Unit 2 Access	3.77%	3.26%	-0.51%
LGE-131500-Mill Creek Unit 2 SO2 Ac	4.97%	4.27%	-0.70%
LGE-131500-Mill Creek Unit 3 Access	2.89%	2.95%	0.06%
LGE-131500-Mill Creek Unit 3 SO2 Ac	4.75%	4.80%	0.05%
LGE-131500-Mill Creek Unit 4 Access	2.16%	2.20%	0.04%
LGE-131500-Mill Creek Unit 4 SO2 Ac	3.15%	3.19%	0.04%
LGE-131500-Mill Crk #3 SO2 ECR 2011	4.75%	4.80%	0.05%
LGE-131500-Mill Crk #4 SO2 ECR 2011	3.15%	3.19%	0.04%
LGE-131500-TC 1 Future Use - 105	2.55%	0.00%	-2.55%
LGE-131500-TC Unit 2 Acce	2.21%	2.21%	0.00%
LGE-131500-TC Unit 2 Acce ECR 2006	2.21%	2.21%	0.00%
LGE-131500-TC Unit 2 Acce ECR 2009	2.21%	2.21%	0.00%
LGE-131500-Trimble 1 Acc ECR 2011	2.26%	2.26%	0.00%
LGE-131500-Trimble Unit 1 Accessory	2.26%	2.26%	0.00%
LGE-131500-Trimble Unit 1 SO2 Acces	0.92%	0.92%	0.00%
LGE-131500-Trimble Unit 2 FGD Acces	0.00%	0.00%	0.00%
LGE-131501-AROP Cane Run 4 Acc	0.00%	0.00%	0.00%
LGE-131501-AROP Cane Run 5 Acc	0.00%	0.00%	0.00%

LGE-131501-AROP Cane Run 6 Acc	0.00%	0.00%	0.00%
LGE-131501-AROP Mill Creek 1 Acc	0.00%	0.00%	0.00%
LGE-131501-AROP Mill Creek 2 Acc	0.00%	0.00%	0.00%
LGE-131501-AROP Mill Creek 3 Acc	0.00%	0.00%	0.00%
LGE-131501-AROP Mill Creek 4 Acc	0.00%	0.00%	0.00%
LGE-131501-AROP Trimble Unit 1 Acc	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 1 Misc. Po	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 3 Misc. Po	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 4 Misc. Po	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 4 SO2 Misc	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 5 Misc. Po	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 5 SO2 Misc	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 6 Misc. Po	0.00%	0.00%	0.00%
LGE-131600-Cane Run Unit 6 SO2 Misc	0.00%	0.00%	0.00%
LGE-131600-Distribution Dr ECR 2011	2.42%	2.42%	0.00%
LGE-131600-Distribution Drive	2.42%	2.42%	0.00%
LGE-131600-MC Unit 1 Misc ECR 2011	4.23%	3.64%	-0.59%
LGE-131600-MC Unit 2 Misc ECR 2011	3.18%	2.82%	-0.36%
LGE-131600-Mill Creek #4 ECR 2011	3.47%	3.52%	0.05%
LGE-131600-Mill Creek Unit 1 Misc P	4.23%	3.64%	-0.59%
LGE-131600-Mill Creek Unit 2 Misc.	3.18%	2.82%	-0.36%
LGE-131600-Mill Creek Unit 3 Misc.	0.77%	0.84%	0.07%
LGE-131600-Mill Creek Unit 4 Misc.	3.47%	3.52%	0.05%
LGE-131600-Mill Creek Unit 4 SO2 Mi	0.04%	0.09%	0.05%
LGE-131600-Trimble Unit 1 Misc. Pow	2.59%	2.59%	0.00%
LGE-131600-Trimble Unit 2 Misc. Pow	2.69%	2.69%	0.00%

LOUISVILLE GAS AND ELECTRIC

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DEPRECIABLE PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	RIVERPORT DISTRIBUTION CENTER	95-R2.5	*	(25)	5,310,284.64	406,568	6,231,288	141,508	2.66	44.0
	MILL CREEK UNIT 1	95-R2.5	*	(11)	21,232,083.22	18,030,458	5,537,154	322,838	1.52	17.2
	MILL CREEK UNIT 2	95-R2.5	*	(11)	14,161,012.84	10,257,954	5,460,770	285,504	2.02	19.1
	MILL CREEK UNIT 2 SCRUBBER	95-R2.5	*	(11)	4,970,628.17	908,754	4,608,643	238,781	4.80	19.3
	MILL CREEK UNIT 3	95-R2.5	*	(11)	29,123,290.17	21,313,461	11,013,391	547,256	1.88	20.1
	MILL CREEK UNIT 3 SCRUBBER	95-R2.5	*	(11)	5,494,516.28	173,524	5,925,389	291,596	5.31	20.3
	MILL CREEK UNIT 4	95-R2.5	*	(11)	73,280,911.39	41,957,732	39,384,080	1,651,403	2.25	23.8
	MILL CREEK UNIT 4 SCRUBBER	95-R2.5	*	(11)	5,792,375.79	2,461,633	3,967,904	164,718	2.84	24.1
	TRIMBLE COUNTY UNIT 1	95-R2.5	*	(14)	107,482,423.29	66,335,130	56,194,833	1,810,718	1.68	31.0
	TRIMBLE COUNTY UNIT 1 SCRUBBER	95-R2.5	*	(14)	889,015.22	6,671	1,006,806	31,696	3.57	31.8
	TRIMBLE COUNTY UNIT 2	95-R2.5	*	(14)	17,403,381.00	2,319,428	17,520,426	375,655	2.16	46.6
	TRIMBLE COUNTY UNIT 2 SCRUBBER	95-R2.5	*	(14)	84,599.93	7,610	88,834	1,903	2.25	46.7
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				285,224,521.94	164,178,923	156,939,518	5,863,576	2.06	26.8
311.20	STRUCTURES AND IMPROVEMENTS - RETIRED PLANT									
	CANE RUN UNIT 1	95-R2.5	*	(10)	1,786,178.29	1,964,796	0	0	-	-
	CANE RUN UNIT 2	95-R2.5	*	(10)	1,228,338.33	1,351,172	0	0	-	-
	CANE RUN UNIT 3	95-R2.5	*	(10)	2,035,561.33	2,239,117	0	0	-	-
	CANE RUN UNIT 4	95-R2.5	*	(10)	3,131,855.49	3,445,041	0	0	-	-
	CANE RUN UNIT 4 SCRUBBER	95-R2.5	*	(10)	17,565.79	19,322	0	0	-	-
	CANE RUN UNIT 5	95-R2.5	*	(10)	3,145,664.22	3,460,231	0	0	-	-
	CANE RUN UNIT 5 SCRUBBER	95-R2.5	*	(10)	10,193.27	11,213	0	0	-	-
	CANE RUN UNIT 6	95-R2.5	*	(10)	13,104,413.12	14,414,854	0	0	-	-
	CANE RUN UNIT 6 SCRUBBER	95-R2.5	*	(10)	85,926.95	94,520	0	0	-	-
	TOTAL ACCOUNT 311.2 - STRUCTURES AND IMPROVEMENTS - RETIRED PLANT				24,545,696.79	27,000,266	0	0	-	-
312.00	BOILER PLANT EQUIPMENT									
	MILL CREEK UNIT 1	60-R1	*	(11)	182,136,143.11	44,904,210	157,266,909	9,490,164	5.21	16.6
	MILL CREEK UNIT 1 SCRUBBER	60-R1	*	(11)	16,929,429.83	10,096,169	8,695,498	532,168	3.14	16.3
	MILL CREEK UNIT 2	60-R1	*	(11)	198,502,284.71	23,329,610	197,007,926	10,741,517	5.41	18.3
	MILL CREEK UNIT 2 SCRUBBER	60-R1	*	(11)	114,821,991.46	3,293,371	124,159,040	6,707,735	5.84	18.5
	MILL CREEK UNIT 3	60-R1	*	(11)	277,512,948.88	68,045,505	239,993,868	12,540,400	4.52	19.1
	MILL CREEK UNIT 3 SCRUBBER	60-R1	*	(11)	150,336,700.73	3,777,361	163,096,377	8,405,284	5.59	19.4
	MILL CREEK UNIT 4	60-R1	*	(11)	471,456,638.57	135,726,909	387,589,960	17,243,238	3.66	22.5
	MILL CREEK UNIT 4 SCRUBBER	60-R1	*	(11)	206,349,248.58	17,667,770	211,379,896	9,308,876	4.51	22.7
	TRIMBLE COUNTY UNIT 1	60-R1	*	(14)	322,917,528.20	90,641,330	277,484,652	9,742,924	3.02	28.5
	TRIMBLE COUNTY UNIT 1 SCRUBBER	60-R1	*	(14)	66,837,564.03	33,565,110	42,629,713	1,543,467	2.31	27.6
	TRIMBLE COUNTY UNIT 2	60-R1	*	(14)	146,448,004.91	25,449,556	141,501,170	3,498,812	2.39	40.4
	TRIMBLE COUNTY UNIT 2 SCRUBBER	60-R1	*	(14)	15,152,263.48	3,036,129	14,237,451	352,682	2.33	40.4
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				2,169,400,746.49	459,533,030	1,965,042,460	90,107,267	4.15	21.8

LOUISVILLE GAS AND ELECTRIC

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
312.10	BOILER PLANT EQUIPMENT - ASH PONDS									
	MILL CREEK UNIT 1 ASH POND	100-S4	*	0	411,750.29	231,546	180,204	45,051	10.94	4.0
	MILL CREEK UNIT 3 ASH POND	100-S4	*	0	947,826.39	635,948	311,878	207,919	21.94	1.5
	TRIMBLE COUNTY UNIT 1 ASH POND	100-S4	*	0	4,867,827.96	1,858,074	3,009,754	501,626	10.30	6.0
	TRIMBLE COUNTY UNIT 2 ASH POND	100-S4	*	0	5,057,242.50	614,262	4,442,980	1,110,745	21.96	4.0
	TOTAL ACCOUNT 312.1 - BOILER PLANT EQUIPMENT - ASH PONDS				11,284,647.14	3,339,830	7,944,816	1,865,341	16.53	4.3
314.00	TURBOGENERATOR UNITS									
	MILL CREEK UNIT 1	60-R2.5	*	(11)	25,971,344.84	11,394,423	17,433,770	1,049,965	4.04	16.6
	MILL CREEK UNIT 2	60-R2.5	*	(11)	28,261,136.61	12,265,240	19,104,622	1,034,236	3.66	18.5
	MILL CREEK UNIT 3	60-R2.5	*	(11)	34,874,136.89	20,843,142	17,867,150	935,800	2.68	19.1
	MILL CREEK UNIT 4	60-R2.5	*	(11)	55,058,036.33	24,696,491	36,417,929	1,608,101	2.92	22.6
	TRIMBLE COUNTY UNIT 1	60-R2.5	*	(14)	59,537,576.82	30,778,475	37,094,363	1,294,397	2.17	28.7
	TRIMBLE COUNTY UNIT 2	60-R2.5	*	(14)	21,967,018.06	4,789,217	20,253,184	485,677	2.21	41.7
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				225,669,249.55	104,766,988	148,171,018	6,408,176	2.84	23.1
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	MILL CREEK UNIT 1	65-R3	*	(11)	18,582,082.97	11,727,023	8,899,089	524,347	2.82	17.0
	MILL CREEK UNIT 1 SCRUBBER	65-R3	*	(11)	202,167.22	220,362	4,044	248	0.12	16.3
	MILL CREEK UNIT 2	65-R3	*	(11)	13,147,191.98	6,468,006	8,125,377	428,984	3.26	18.9
	MILL CREEK UNIT 2 SCRUBBER	65-R3	*	(11)	2,694,916.35	765,601	2,225,756	114,967	4.27	19.4
	MILL CREEK UNIT 3	65-R3	*	(11)	26,791,012.14	13,984,708	15,753,315	789,175	2.95	20.0
	MILL CREEK UNIT 3 SCRUBBER	65-R3	*	(11)	9,792,181.78	1,349,963	9,519,359	469,685	4.80	20.3
	MILL CREEK UNIT 4	65-R3	*	(11)	31,002,634.31	18,728,455	15,684,469	683,556	2.20	22.9
	MILL CREEK UNIT 4 SCRUBBER	65-R3	*	(11)	1,667,316.69	564,201	1,286,521	53,168	3.19	24.2
	TRIMBLE COUNTY UNIT 1	65-R3	*	(14)	65,098,801.60	30,167,182	44,045,452	1,473,149	2.26	29.9
	TRIMBLE COUNTY UNIT 1 SCRUBBER	65-R3	*	(14)	2,736,920.21	2,395,614	724,475	25,313	0.92	28.6
	TRIMBLE COUNTY UNIT 2	65-R3	*	(14)	10,679,138.16	1,552,448	10,621,770	235,871	2.21	45.0
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				182,394,363.41	87,923,563	116,889,627	4,798,463	2.63	24.4
316.00	MISCELLANEOUS PLANT EQUIPMENT									
	RIVERPORT DISTRIBUTION CENTER	45-R2.5	*	(2)	582,917.96	63,737	530,839	14,119	2.42	37.6
	MILL CREEK UNIT 1	45-R2.5	*	(11)	1,036,757.76	560,951	589,850	37,736	3.64	15.6
	MILL CREEK UNIT 2	45-R2.5	*	(11)	141,316.22	90,413	66,448	3,982	2.82	16.7
	MILL CREEK UNIT 3	45-R2.5	*	(11)	347,546.48	334,551	51,226	2,930	0.84	17.5
	MILL CREEK UNIT 4	45-R2.5	*	(11)	10,935,346.35	3,654,057	8,484,177	384,552	3.52	22.1
	MILL CREEK UNIT 4 SCRUBBER	45-R2.5	*	(11)	43,211.57	47,101	864	38	0.09	22.7
	TRIMBLE COUNTY UNIT 1	45-R2.5	*	(14)	3,093,853.20	1,635,209	1,891,784	80,052	2.59	23.6
	TRIMBLE COUNTY UNIT 2	45-R2.5	*	(14)	3,528,603.03	384,869	3,637,738	94,925	2.69	38.3
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT				19,709,552.57	6,770,888	15,252,926	618,334	3.14	24.7
	TOTAL STEAM PRODUCTION PLANT				**2,918,228,777.89**	**853,513,488**	**2,410,240,365**	**109,661,157**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

LOUISVILLE GAS AND ELECTRIC

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2015

		Terminal Retirements			Interim Retirements			Total		Estimated
Account	Retirements ($)	Net Salvage ($)	Net Salvage (%)	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Net Salvage ($)	Total Retirements	Net Salvage (%)
(1)	(2)	(3)	(4)=(3)/(2)	(5)	(6)	(7)=(5)x(6)	(8)=(3)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
STEAM PRODUCTION PLANT									
CANE RUN GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	16,811,037	(1,681,104)	(10)	-	(25)	-	(1,681,103.73)	16,811,037	(10)
312 BOILER PLANT EQUIPMENT	5,944,973	(594,497)	(10)	-	(25)	-	(594,497)	5,944,973	(10)
314 TURBOGENERATOR UNITS	1,180,444	(118,044)	(10)	-	(15)	-	(118,044)	1,180,444	(10)
315 ACCESSORY ELECTRIC EQUIPMENT	1,121	(112)	(10)	-	(15)	-	(112)	1,121	(10)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	608,122	(60,812)	(10)	-	(2)	-	(60,812)	608,122	(10)
TOTAL CANE RUN GENERATING STATION	*24,545,697*	*(2,454,570)*		-		-	*(2,454,570)*	*24,545,697*	*(10)*
MILL CREEK GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	124,467,927	(11,202,113)	(9)	29,586,891	(25)	(7,396,723)	(18,598,836)	154,054,818	(11)
312 BOILER PLANT EQUIPMENT	1,365,643,392	(122,907,905)	(9)	252,401,993	(25)	(63,100,498)	(186,008,404)	1,618,045,386	(11)
314 TURBOGENERATOR UNITS	116,197,216	(10,457,749)	(9)	27,967,438	(15)	(4,195,116)	(14,652,865)	144,164,655	(11)
315 ACCESSORY ELECTRIC EQUIPMENT	85,177,960	(7,666,016)	(9)	18,701,544	(15)	(2,805,232)	(10,471,247.93)	103,879,503	(11)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	9,674,322	(870,689)	(9)	2,829,857	(2)	(56,597)	(927,286)	12,504,178	(11)
TOTAL MILL CREEK GENERATING STATION	*1,701,160,817*	*(153,104,474)*		*331,487,723*		*(77,554,166)*	*(230,658,639)*	*2,032,648,540*	*(11)*
TRIMBLE COUNTY GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	112,342,178	(10,110,796)	(9)	13,517,241	(25)	(3,379,310)	(13,490,106)	125,859,419	(14)
312 BOILER PLANT EQUIPMENT	340,306,097	(30,627,549)	(9)	211,049,263	(25)	(52,762,316)	(83,389,865)	551,355,361	(14)
314 TURBOGENERATOR UNITS	52,942,160	(4,764,794)	(9)	28,562,435	(15)	(4,284,365)	(9,049,160)	81,504,595	(14)
315 ACCESSORY ELECTRIC EQUIPMENT	52,876,881	(4,758,919)	(9)	25,637,979	(15)	(3,845,697)	(8,604,616)	78,514,860	(14)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,151,292	(283,616)	(9)	3,471,164	(2)	(69,423)	(353,040)	6,622,456	(14)
TOTAL TRIMBLE COUNTY GENERATING STATION	*561,618,609*	*(50,545,675)*		*282,238,082*		*(64,341,112)*	*(114,886,786)*	*843,856,691*	*(14)*
TOTAL STEAM PRODUCTION PLANT	**2,287,325,122**	**(206,104,718)**		**613,725,806**		**(141,895,277)**	**(347,999,995)**	**2,901,050,928**	