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, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00350**

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

Filed: November 25, 2020

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Exhibits

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. My business address is 2604 Sunningdale Place East, La Grange, Kentucky 40031.

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

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

Q. On whose behalf are you testifying in these proceedings?

A. I am testifying on behalf of Kentucky Utilities Company ("KU"), which provides electric service to utilities throughout Kentucky, and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"), which provides both electric and natural gas sales and delivery services in Louisville-Jefferson County and surrounding counties in Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the proposed allocation of the revenue increases for KU and for LG&E's electric and natural gas operations; (ii) to support KU and LG&E's proposed rates; (iii) to sponsor the fully allocated cost of service studies based on KU and LG&E's embedded cost of providing electric and natural gas service for the fully forecasted test year, which is the 12 months beginning July 1, 2021; and (iv) to sponsor the revenue lag portion of the updated revenue lag study for KU and LG&E.

Q. Please summarize your testimony.

A. My direct testimony addresses the following:

- **Cost of Service Studies and the Allocation of the Revenue Increase.** In developing their proposed rates in these proceedings, KU and LG&E considered the results of the cost of service studies. The purpose of a class cost of service study is to determine the contribution that each customer class is making towards the utility's overall rate of return. Cost of service is a standard measure of reasonableness for utility rate design. Rates of return are calculated for each rate class. In the electric cost of service studies, production fixed costs were allocated based on hourly class loads weighted by the hourly Loss of Load Probability ("LOLP"), which is a key measure that has been used by KU and LG&E for many years to plan their generation resources. The Companies used the LOLP as an electric cost of service methodology in their 2016 and 2018 rate cases. In accordance with the Commission's Order in Case Nos. 2018-00294 and 2018-00295, KU and LG&E are also submitting 6 Coincident Peak ("6-CP") and 12 Coincident Peak ("12-CP") cost of service studies as alternatives to the LOLP cost of service proposed by the Companies. LG&E's gas cost of service study used the same methodology as was filed in its 2018 and prior rate cases. The Companies' class cost of service studies were also used as a guide for allocating the revenue increase to the rate classes and for developing unit charges for electric and gas service.

- **Elimination of Environmental Cost Recovery (ECR) Surcharge and Gas Line Tracker (GLT) Projects**. KU and LG&E are proposing to eliminate certain ECR projects. LG&E is also proposing to eliminate all but two GLT projects. The test-year costs of these projects will be transferred into base rates.

- **Continued Separation of Rates into Infrastructure and Variable Cost Components.** KU and LG&E are also proposing to continue to separate out the infrastructure and variable cost components of the energy charge for Residential Service (Rate RS), General Service (Rate GS) and other two-part rates that include only a customer charge and an energy charge. The purpose of this structure in the presentation of these rate schedules is to provide more information to customers, stakeholders and employees about which costs are avoidable through the installation of distributed generation (i.e., the variable cost component) and which costs are less likely to be avoided (i.e., the fixed cost component). In its Orders in Case Nos. 2018-00294 and 2018-00295, the Commission ruled that splitting the energy charges into infrastructure and variable components for information purposes is reasonable. My testimony will address the continued importance of this practice.

- **Residential Time-of-Day Services.** The Companies are proposing to modify Residential Time-of-Day Service (Rates RTOD-E and RTOD-D) to shift the morning peak period by one hour to more accurately reflect current peak periods and to add evening hours to the winter peak period. The on- and off-peak charges are adjusted to reflect this change.

- **General Time-of-Day Services**. The Companies are proposing to offer optional General Time of Day Services (Rate GTOD – Energy and GTOD - Demand) rate schedules that would be available to any General Service (Rate GS) customer enrolled under the Advanced Metering Systems Customer Service Offering set forth in the Companies' Demand-Side Management Cost Recovery Mechanism.

- **Lighting Rates.** The Companies are introducing three new light emitting diode (LED) lighting offerings. In its Orders in Case Nos. 2018-00294 and 2018-00295, the Commission approved an LED Conversion Fee that applies whenever a customer requests the replacement of a working non-LED fixture with an LED fixture prior to the failure of the non-LED fixture. The current LED Conversion Fee, which provides for the recovery of the stranded costs created by the replacement of a working non-LED fixture with an LED fixture, is a fixed charge that applies for a period of five years. The Companies are proposing to offer an alternative in which customers can make an up-front payment of the LED Conversion Fee. For Outdoor Sports Lighting Service (Rate OSL), the Companies are proposing to reduce the number of hours during the peak period by one hour.

- **Net Metering.** In March 2019, Senate Bill 100 was signed into law thereby modifying 278.466 to allow each electric utility to implement rates to recover from *non-grandfathered* or *new* net metering customers "all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators." The Companies are proposing a new net metering service called "Net Metering Service 2 – NMS 2" that will be applicable to new net metering customers taking service on or after the effective date of the new rates approved in these proceedings.

- **Electric Vehicle Rates.** The Companies are proposing to offer a new Electric Vehicle Fast Charging Service (Rate EV-FAST). Under the proposed rate, KU and LG&E would charge $0.25 per kWh for charging at Direct Current Fast

Charging Stations (DCFCs) that would be installed by the Companies in late 2022. Because spending for the stations would occur after the end of the forecasted test year in these proceedings, none of the costs are included in revenue requirements.

- **Annual Waiver of Non-Residential Late Payment Charges.** In Case Nos. 2018-00294 and 2018-00295, the Companies implemented a program to waive late payment charges for residential customers who have not been late in paying their bills during each of the previous 11 months. The Companies are proposing to extend this practice to non-residential customers.

- **Miscellaneous Charges.** The Companies are proposing changes in certain miscellaneous charges to reflect changes in costs. The Companies are also proposing miscellaneous charges related to the proposed Advanced Metering Infrastructure (AMI) deployment.

- **Update to the Lead-Lag Studies.** The revenue lags in the study submitted in the Companies' last rate cases were updated for the calendar year 2019.

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

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

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

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Electric Rate Design and the Allocation of the Increases, (IV) Gas Rate Design and the Allocation of the Increase, (V) Miscellaneous Service Charges, (VI) Advanced Metering Infrastructure (AMI), (VII) Electric Cost of Service Studies, (VIII) Gas Cost of Service Study, and (IX) Lead-Lag Studies.

II. QUALIFICATIONS

Q. Please describe your educational and professional background.

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

Concerning my professional background, from May 1979 until July 1996, I was employed by LG&E. From May 1979 until December 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed or supervised the preparation of cost of service and rate studies for over 150 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. Therefore, including my time at LG&E, I have more than 40 years of experience in the utility industry. A more detailed description of my qualifications is included in Exhibit WSS-1.

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

A. Yes. I have testified in over 75 regulatory and court proceedings in 13 different jurisdictions. I have testified before the Kentucky Public Service Commission on behalf of both KU and LG&E, as well as on behalf of other utilities, on numerous occasions. A listing of my testimony in other proceedings is included in Exhibit WSS-1.

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

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

III. ELECTRIC RATE DESIGN AND THE ALLOCATION OF THE INCREASES

A. ALLOCATION OF THE ELECTRIC INCREASES

Q. Please summarize your recommendations for allocating the electric revenue increases to the classes of service.

A. The Companies are proposing an overall revenue increase of $170,120,598 for KU, which corresponds to a 10.36% increase, and a $131,073,276, revenue increase for LG&E, which corresponds to an 11.61% increase. The Companies are also proposing changes in miscellaneous charges which result in changes to other operating revenue. Accounting for changes in other operating revenue, the overall increase in revenues from *sales to ultimate customers* is \$169,747,181 (or 10.57%) for KU and \$130,983,319 (or 11.83%) for LG&E. (See Schedule M-2.1 for KU and Schedule M-2.1-E for LG&E in the Companies' Filing Requirements.)

Except for the lighting rates, KU is proposing to increase revenues for all rate classes by approximately 10.68%. Based on the results of the cost of service study, KU is proposing no net increases, within rounding, for Lighting Service (Rate LS), Restricted Lighting Service (Rate RLS), Lighting Energy Service (Rate LE), and Traffic Energy Service (TE). KU is proposing a rate reduction for Outdoor Lighting Service (Rate OSL), which is an optional pilot program, of approximately 5.00%. KU is proposing no changes to the rate credits set forth in its Curtailable Service Rider (CSR).

Except for three lighting rates, LG&E is proposing to increase revenues for all rate classes by approximately 11.80%. LG&E is proposing no increases, within rounding, for Lighting Energy Service (Rate LE) and Traffic Energy Service (TE). LG&E is proposing a rate reduction for Outdoor Lighting Service (Rate OSL), which is an optional pilot program, of approximately 10.00%. LG&E is proposing no changes to the rate credits set forth in its Curtailable Service Rider (CSR).

Both KU and LG&E are proposing to increase the disconnect/reconnect charges and returned check charges. The Companies are proposing to decrease the unauthorized reconnect charges. KU and LG&E are proposing minor changes to certain other miscellaneous charges, which will be discussed later in my testimony.

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

A. Yes. The electric revenue increases for each rate class are shown on Schedule M-2.1 of Section 16(8)(m) of the Filing Requirements for KU and Schedule M-2.1-E of Section 16(8)(m) of the Filing Requirements for LG&E. The detailed billing calculations for each rate schedule are shown on Schedule M-2.3 for KU and Schedule M-2.3-E for LG&E. The proposed unit charges for each rate schedule are shown on these schedules.

B. ELIMINATION OF ENVIRONMENTAL COST RECOVERY (ECR) PROJECTS

Q. Are the Companies proposing to eliminate certain Environmental Cost Recovery (ECR) projects?

A. Yes. KU is proposing to eliminate projects 28 through 31 of the 2009 ECR Plan, all projects in the 2011 ECR Plan, and projects 36 through 38 of the 2016 ECR Plan. LG&E is proposing to eliminate projects 22 and 23 of the 2009 ECR Plan, all projects in the 2011 ECR Plan, and project 28 of the 2016 ECR Plan. Because work will have been completed on these projects prior to the end of the test year (or, in the case of LG&E, Project 22, because the project was cancelled), the Companies are proposing to eliminate them from recovery through the ECR mechanism.

Q. Will the costs of these eliminated ECR projects be recovered through base rates

instead of the ECR?

A. Yes. The impact of these projects is also shown in Schedule M-2.3 for KU and Schedule M-2.3-E for LG&E and in the supporting detail for those schedules. Specifically, on page 1 of these Schedules, the column labeled "Base Rate ECR Adjustment to Reflect ECR Project Elimination" reflects the amount of base rate ECR revenue transferred to base rate revenue, and the column labeled "ECR Mechanism Adjustment to Reflect ECR Project Elimination" reflects the amount of ECR Mechanism revenue transferred to base rates. These adjustments *do not* alter total revenue, but simply represent the removal of ECR costs for the eliminated projects from the ECR mechanism into base rate recovery. These adjustments are revenue neutral. The supporting details for each rate class are shown on pages 2 through 26 of these schedules.

C. RESIDENTIAL SERVICE (RATE RS)

Q. Please provide a brief description of Rate RS.

A. Rate RS is the standard electric rate schedule available to single-family residential service. KU and LG&E serve approximately 442,000 and 377,000 residential customers, respectively, under this rate schedule. Rate RS has a two-part rate structure that includes a Basic Service Charge and an Energy Charge.

Q. What are the charges that KU and LG&E are proposing for Rate RS?

A. KU is proposing a Basic Service Charge of $0.61 per day, and LG&E is proposing a Basic Service Charge of $0.52 per day. For KU, the charge would increase from $0.53

to $0.61, which corresponds to a 15.1% increase. For LG&E, the charge would increase from $0.45 to $0.52 per day, which again corresponds to 15.6% increase. For both Companies, the Basic Service Charges were designed to reflect 75% of the customer-related costs calculated in the cost of service studies.[1] The customer-related cost for KU is $0.82 per day; thus, KU's proposed Basic Service Charge of $0.61 per day represents 75% of the customer cost from the cost of service study ($0.61 ÷ $0.82 = 75%). The customer-related cost for LG&E is $0.69 per day; therefore, LG&E's proposed Basic Service Charge of $0.52 also represents 75% of the customer cost ($0.52 ÷ $0.69 = 75%). Although higher Basic Service Charges could be supported based on results of the Companies' cost of service studies, the increase was capped at 75% of customer costs to reflect the ratemaking principles of rate continuity and gradualism. KU is proposing to increase its energy charge from $0.08963 per kWh to $0.09950 per kWh. LG&E is proposing to increase its energy charge from $0.09278 per kWh to $0.10482 per kWh.

Q. Are the Companies proposing to continue to separate the energy charge into a variable cost component and a fixed cost component?

A. Yes. In its Orders in Case Nos. 2018-00294 and 2018-00295, the Commission ruled that splitting the energy charges into variable cost component (Variable Energy Charge) and fixed cost component (Infrastructure Energy Charge) for informational

[1] In its Oder in Case No.2018-00295, the Commission required that the Basic Service Charge for both KU and LG&E represent the same percentage of the customer-related costs from the Companies' cost of service studies. See Case No. 2018-00295, Order at 25 (Ky. P.S.C. April 30, 2019). The Companies' proposal in the current proceedings is consistent with that directive.

purposes is reasonable. For KU, the proposed Variable Energy Charge is $0.03200 per kWh, and the proposed Infrastructure Energy Charge is $0.06750 per kWh. For LG&E, the proposed Variable Energy Charge is $0.03245 per kWh, and the proposed Infrastructure Energy Charge is $0.07237 per kWh.

Q. Why do the Companies separate their energy charges into variable and fixed components?

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

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

A. The following table (TABLE 1) shows how the cost of providing service to customers under Rate RS is broken down between customer-related fixed costs, demand-related fixed costs, and energy-related variable costs for KU and LG&E:

TABLE 1

Cost Component	KU Percentage of Cost	LG&E Percentage of Cost
Customer-Related Fixed Costs	19.41%	19.74%
Demand-Related Fixed Costs (Infrastructure Demand Costs)	52.61%	53.18%
Energy-Related Variable Costs	27.98%	27.08%

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

A. Rate RS, as well as a number of the Companies' other rate schedules that serve smaller commercial and industrial customers (for example Rate GS), are currently structured as a *two-part rate* consisting of a customer charge (Basic Service Charge) and an Energy Charge. The Basic Service Charge is billed as a flat daily charge per customer, and the Energy Charge is billed on a cents-per-kWh basis. Under a two-part rate design, all *three cost components* (customer costs, demand costs and energy costs) are recovered through *two rate components* (customer charge and energy charge). Unlike the three- and multi-part rates that are used for larger customers, the two-part rate for Rate RS does not utilize a demand charge. Therefore, demand costs (costs associated with transformers, overhead and underground conductor, transmission lines, and generation capacity) must be recovered through either the customer charge or an energy charge. For Rate RS, all demand costs and a portion of the customer costs are currently being recovered through the Energy Charge, which includes the Infrastructure Energy Charge and the Variable Energy Charge. The following tables compare the percentage of costs broken down by component (customer cost, demand cost, and energy cost) to the percentage of recovery through the proposed rate components (customer charge and energy charge) for KU (TABLE 2) and LG&E (TABLE 3):

TABLE 2 – KU

Component	Percentage of Cost	Rate Design
Customer	19.41%	14.5%
Demand	52.61%	0.0%
Energy	27.98%	85.5%

TABLE 3 – LG&E

Component	Percentage of Cost	Rate Design
Customer	19.74%	14.8%
Demand	53.18%	0.0%
Energy	27.08%	85.2%

As can be seen from these tables, all demand costs and a significant portion of customer costs are currently recovered through the Energy Charge.

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

A. A *three-part rate* is a rate structure that includes a customer charge, energy charge and demand charge. KU and LG&E's rate for medium commercial and industrial customers (Rate PS) is a three-part rate consisting of a customer charge, energy charge and demand charge. The rates for large commercial and industrial customers (Rates TODS, TODP, RTS, and FLS) are structured as a *multi-part rate* consisting of a customer charge, energy charge and multi-part demand charge that is unbundled between production fixed cost components and transmission/distribution fixed cost components. The reason that a two-part rate structure traditionally has been used in the industry for residential and small commercial and industrial accounts is that the cost of the metering technology necessary to bill a three- or multi-part rate for small customers has been prohibitive. In my experience, this is changing in the industry. As utilities install advanced metering technology for all types of customers, it becomes more feasible to use three- or multi-part rates for residential and general service (small commercial and industrial) customers and thereby offer rates that more accurately reflect cost of service. Multi-part rates allow customers to better manage their load by shifting their usage pattern to avoid higher peak period charges. Several utilities in the U.S. have implemented three- and multi-part rates for residential and small general service customers. This is a trend in the industry that I believe the Companies and the Commission should closely monitor.

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

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

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

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

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

A. Yes. Exhibit WSS-2 shows the calculation of the unit customer cost, demand related cost, and energy costs from the Companies' cost of service studies. From this calculation, the customer cost for KU is $0.82 per customer per day; the demand-related cost (infrastructure cost) is $0.06017/kWh; and the energy cost (variable cost) is $0.03200/kWh. KU is proposing to increase the Basic Service Charge from $0.53 per day to $0.61 per day, which corresponds to a 15.1% increase in the charge. KU's proposed Basic Service Charge of $0.61 per day is 75% of the unit cost from KU's cost of service study.

The customer cost for LG&E is $0.69 per customer per day; the demand-related cost is $0.06371/kWh; and the energy cost is $0.03245/kWh. LG&E is proposing to increase the Basic Service Charge from $0.45 per day to $0.52 per day, which corresponds to a 15.6% increase in the charge. LG&E's proposed Basic Service Charge of $0.52 is 75% of the unit cost from LG&E's cost of service study. The Companies are proposing Basic Service Charges for Rate RS that reflect only 75% of customer costs, which correspond to percentage increases in the Basic Service Charges of less than 16%, to reflect the ratemaking principles of rate continuity and gradualism. It should be noted, however, that in the last several years the Commission has allowed a number of utilities to increase their customer charges by close to 50%.

For example, in its Order in Case No. 2019-00066, the Commission authorized a 46% increase in Jackson Energy Cooperative Corporation's residential customer charge increasing the customer charge from $16.44 to $24.00 per month.[2]

Q. Please describe the type of costs that are recovered through the Basic Service Charge.

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

Q. What other costs need to be considered in developing the Basic Service Charge?

A. Customers often need more equipment than the minimum system in order to receive adequate service. The cost of this equipment above the minimum is related to the customer's usage level and is a demand-related fixed cost that is recovered through either a demand or energy charge. A cost of service study is performed for the purpose of allocating costs as accurately as possible based on cost causation. In a cost of

[2] *Electronic Application of Jackson Energy Cooperative Corporation for a General Adjustment in Existing Rates*, Case No. 2019-00066, Order at 8 (Ky. P.S.C. June 19, 2019).

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

Q. Will the Companies' proposed Basic Service Charges recover all of KU and LG&E's customer-related costs for Rate RS?

A. No. KU's proposed Basic Service Charge of $0.61 per day does not recover all of the customer-related fixed costs of $0.82 per day. Likewise, LG&E's proposed Basic Service Charge of $0.52 per day does not fully recover the customer-related fixed costs of $0.69 per day. The differences between the proposed Basic Service Charge and customer-related fixed costs will therefore be recovered in the energy charge.

Q. Will the Companies' proposed residential rates help to reduce subsidies?

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

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

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

Increasing the Basic Service Charge by a larger percentage than the energy charge will help reduce subsidies by bringing the charges toward the actual cost of providing service. Increasing KU's Basic Service Charge from $0.53 per day to $0.61 per day and increasing LG&E's Basic Service Charge from $0.45 per day to $0.52 per day will eliminate some, but not all, of the subsidies that high-usage customers are currently providing low-usage customers.

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

Q. Please provide a brief description of the Companies' residential time-of-day rates.

A. The Companies offer two residential time-of-day rates, RTOD-Energy and RTOD-Demand. Rate RTOD-Energy is a time-of-day rate that includes a time differentiated energy charge. Under the rate, customers are charged a significantly lower energy charge for off-peak usage. Rate RTOD-Demand is a time-of-day rate that includes a flat energy charge but a time differentiated demand charge.

Q. Are the Companies proposing changes to the time-of-day periods (rating periods)

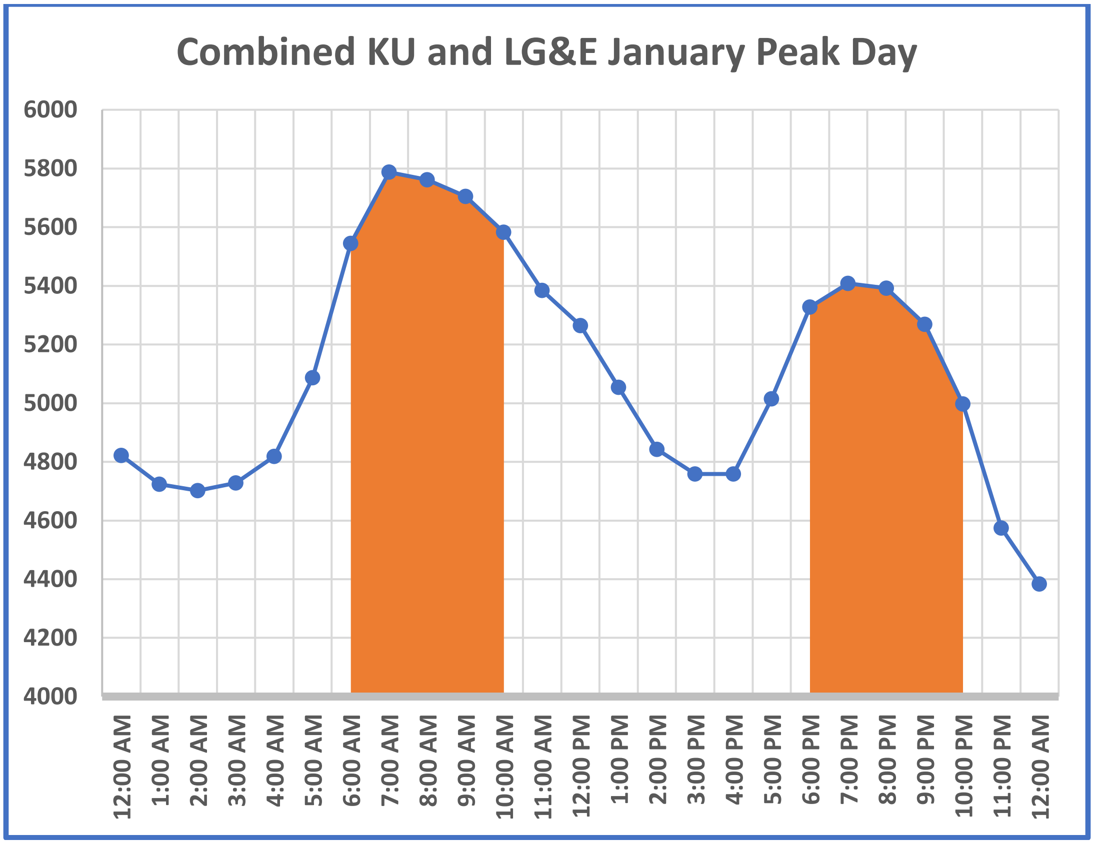
for their RTOD rates?

A. Yes. The Companies are proposing to modify the on-peak period during the months of November through March ("Winter Months") for both RTOD-Energy and RTOD-Demand. The on-peak period during the Winter Months are currently 7 AM to 11 AM. KU and LG&E are proposing to redefine the on-peak period during the Winter Months as the hours between from 6 AM to 10 AM and from 6 PM to 10 PM. With this change, the morning on-peak period will be shifted by one hour earlier in the morning, and non-contiguous evening hours will be added to the on-peak period to capture a secondary daily peak that occurs on the combined KU and LG&E system during the evening.

Q. Why are these changes to the on-peak period being made?

A. The new on-peak hours will more accurately reflect the hours when a peak on the combined KU and LG&E system would likely occur during the Winter Months. Because the Companies plan their generation resources to meet their combined load, it is appropriate to define the peak period as the hours during which the combined system peak would likely occur. Another objective is to define the peak period as narrowly as practicable so that customers can manage their loads to avoid higher on-peak charges, while still reflecting the period during which the Companies' peak will likely occur. During the Winter Months, the Companies' hourly combined system load will exhibit a pronounced peak during the morning and another during the evening. In the industry, this is referred to vernacularly as a "double hump", and is illustrated in the following graph (GRAPH 1) showing the hourly expected load in MW for a January peak:

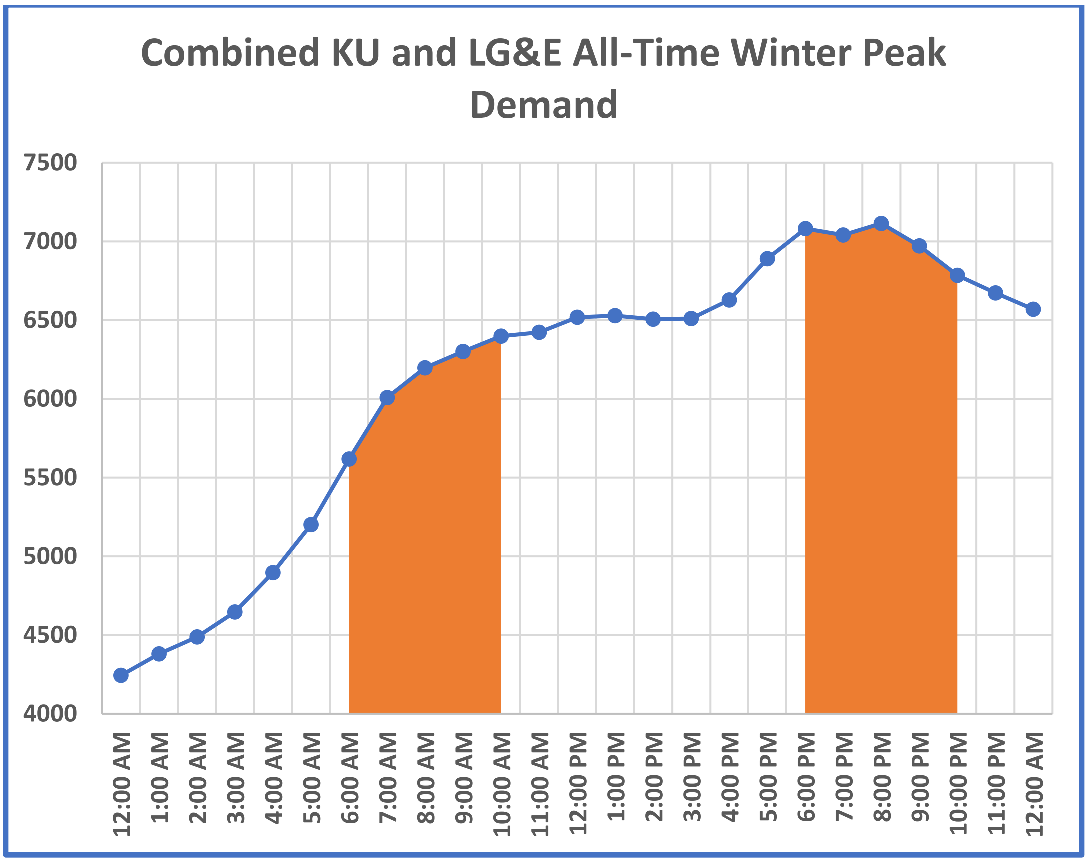
GRAPH 1



This graph shows the typical hourly load pattern for KU and LG&E's combined system on a winter peak day, with the evening peak somewhat lower than the morning peak. While the peak during the Winter Months will typically occur during the morning hours, the Companies' all-time winter peak occurred during the evening.

GRAPH 2 shows the hourly loads in MW for the Companies' all-time highest winter peak that occurred on January 6, 2014:

GRAPH 2



As seen in the graph, the Companies proposed on-peak period would encompass this all-time winter system peak.

Q. What charges are KU and LG&E proposing for Rate RTOD-Energy?

A. KU is proposing to increase the Basic Service Charge from $0.53 per day to $0.61 per day, to increase the off-peak Energy Charge from $0.05760 per kWh to $0.06512 per kWh, and to decrease the on-peak Energy Charge from $0.27542 per kWh to $0.22124 per kWh. LG&E is proposing to increase the Basic Service Charge from $0.45 per day to $0.52 per day, to increase the off-peak Energy Charge from $0.07080 per kWh to $0.08180 per kWh, and to decrease the on-peak Energy Charge from $0.20508 per kWh to $0.17949 per kWh. The proposed Basic Service Charges for the Companies are the same as for Rate RS. The increases in the off-peak Energy Charges and decreases in the on-peak Energy Charges account for proposed changes to the off-peak and on-peak hours during the Winter Months described above.

Q. What charges are KU and LG&E proposing for Rate RTOD-Demand?

A. KU is proposing a Basic Service Charge of $0.61 per day, an Energy Charge of $0.04476 per kWh, a Base Demand charge of $4.01 per kW, and a Peak Demand charge of $10.37 per kW. LG&E is proposing a Basic Service Charge of $0.52 per day, an Energy Charge of $0.05340 per kWh, a Base Demand charge of $4.22 per kW, and a Peak Demand charge of $9.25 per kW. The energy charge for Rate RTOD-Demand is broken down into Variable Energy Charge and Infrastructure Energy Charge components.

E. GENERAL SERVICE (RATE GS)

Q. Please provide a brief description of Rate GS.

A. Rate GS is the standard electric rate schedule available to small commercial and industrial customers served at secondary voltages (available voltages *less than*

2,400/4,160Y volts). The rate schedule is limited to customers whose 12-month average monthly demands do not exceed 50 kW. Approximately 83,000 small commercial and industrial customers are served under Rate GS on KU and approximately 45,000 are served under Rate GS on LG&E. Rate GS has a two-part rate structure that includes a Basic Service Charge and an Energy Charge.

Q. What charges are the Companies proposing for Rate GS?

A. KU is proposing an increase in the Basic Service Charge for Rate GS from $1.04 per day to $1.35 per day for single-phase service and from $1.66 per day to $2.15 per day for three-phase service. LG&E is proposing an increase in the Basic Service Charge for Rate GS from $1.04 per day to $1.16 per day for single-phase service and from $1.66 per day to $1.85 per day for three-phase service. KU is proposing to increase the energy charge from $0.11225 per kWh to $0.12469 per kWh, and LG&E is proposing to increase the energy charge from $0.10530 per kWh to $0.12355 per kWh. As with Rate RS, the energy charge for Rate GS is broken down into Variable Energy Charge and Infrastructure Energy Charge components. For KU the proposed Variable Energy Charge is $0.03253 per kWh, and the proposed Infrastructure Energy Charge is $0.09216 per kWh. For LG&E the proposed Variable Energy Charge is $0.03340 per kWh, and the proposed Infrastructure Energy Charge is $0.09015 per kWh.

F. GENERAL TIME-OF-DAY SERVICE (RATE GTOD)

Q. Are the Companies proposing a General Time-of-Day service?

A. Yes. The Companies are proposing to offer optional General Time-of-Day Service

(Rate GTOD-Energy and GTOD-Demand) standard rates that would be available to any General Service (Rate GS) customer enrolled under the Advanced Metering Systems Customer Service Offering set forth in the Companies' Demand-Side Management Cost Recovery Mechanism. Currently there are approximately 460 KU and LG&E customers enrolled under the Advanced Metering Systems Customer Service Offering that would be eligible to take service under Rate GTOD-Energy or GTOD-Demand.

Q. Please describe the rate structure for Rate GTOD-Energy.

A. Rate GTOD-Energy will have the same pricing structure as RTOD-Energy. Specifically, GTOD-Energy will consist of a Basic Service Charge and a time-differentiated Energy Charge consisting of an Off-Peak Charge and an On-Peak Charge. During the Summer Months of April through October, the On-Peak will be 1:00 PM to 5:00 PM on weekdays, with all other hours considered Off-Peak. During the Non-Summer Months of November through March, the On-Peak will be 6 AM to 10 AM in the morning and 6 PM to 10 PM in the evening, with all other hours considered Off-Peak.

Q. What charges are KU and LG&E proposing for GTOD-Energy?

A. KU is proposing a Basic Service Charge $1.35 per day for single-phase service and $2.15 per day for three-phase service. KU is proposing an off-peak Energy Charge of $0.08094 per kWh and an on-peak Energy Charge of $0.30029 per kWh. LG&E is proposing a Basic Service Charge $1.16 per day for single-phase service and $1.85 per day for three-phase service. LG&E is proposing an off-peak Energy Charge of

$0.08075 per kWh and an on-peak Energy Charge of $0.24797 per kWh.

Q. Please describe the rate structure for Rate GTOD-Demand.

A. Rate GTOD-Demand will have the same pricing structure as RTOD-Demand. Specifically, GTOD-Demand will consist of a Basic Service Charge, Energy Charge, Peak Demand Charge, and Base Demand Charge. During the Summer Months of April through October, the On-Peak will be 1:00 PM to 5:00 PM on weekdays, with all other hours considered Off-Peak. During the Non-Summer Months of November through March, the On-Peak will be 6 AM to 10 AM in the morning and 6 PM to 10 PM in the evening, with all other hours considered Off-Peak.

Q. What charges are KU and LG&E proposing for GTOD-Demand?

A. KU is proposing a Basic Service Charge of $1.35 per day for single-phase service and $2.15 per day for three-phase service. KU is proposing an Energy Charge of $0.06916 per kWh, Peak Demand Charge of $14.16 per kW per month, and Base Demand Charge of $5.47 per kW per month. LG&E is proposing a Basic Service Charge $1.16 per day for single-phase service and $1.85 per day for three-phase service. LG&E is proposing an Energy Charge of $0.05950 per kWh, Peak Demand Charge of $11.75 per kW per month, and Base Demand Charge of $5.37 per kW per month. Exhibit WSS-3 shows the cost support for the charges.

G. ALL ELECTRIC SCHOOLS SERVICE (AES) (KU ONLY)

Q. Please provide a brief description of Rate AES.

A. Rate AES is a KU-only rate generally available for school buildings, although the rate is closed to new customers and is limited to customers that were qualified for, and being served on, Rate AES as of July 1, 2011. There are approximately 420 schools taking service under Rate AES. KU is proposing to increase the energy charge from \$0.08732 per kWh to \$0.10079 per kWh. The energy charge for Rate AES is broken down into Variable Energy Charge and Infrastructure Energy Charge components. The proposed Variable Energy Charge is \$0.03223 per kWh, and the proposed Infrastructure Energy Charge is \$0.06856 per kWh.

H. POWER SERVICE (RATE PS)

Q. What charges are the Companies proposing for Rate PS?

A. Rate PS is available for large commercial and industrial customers served at secondary voltages (available voltages less than 2,400/4,160Y volts) whose 12-month average loads exceed 50 kW but do not exceed 250 kW and for large commercial and industrial customers served at primary voltages (2,400/4,160Y volts, 7,200/12,470Y volts, or 34,500 volts) whose 12-month average do not exceed 250 kW. The rate changes proposed for Rate PS are shown on Schedule M-2.3 for KU and Schedule M-2.3-E for LG&E.

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

Q. What are the standard large customer rates offered by KU and LG&E?

A. KU and LG&E offer four standard rates for large commercial and industrial customers: Time-of-Day Secondary Service (Rate TODS), Time-of-Day Primary

Service (Rate TODP), Retail Transmission Service (Rate RTS), and Fluctuating Load Service (Rate FLS). Rate TODS is available to customers served at secondary voltages (available voltages less than 2,400/4,160Y volts) with average demands between 250 kW and 5,000 kW. Rate TODP is available to customers served at primary voltages (2,400/4,160Y volts, 7,200/12,470Y volts, or 34,500 volts) with average demands greater than 250 kVA. Rate RTS is available to customers served at transmission voltages (69,000 volts or higher) with average demands greater than 250 kVA. Rate FLS is available to customers served at primary or transmission voltage whose demands are 20,000 kW or greater. Customers with demands of 20,000 kW or greater whose load either increases or decreases 20 MVA or more per minute or whose load either increases or decreases 70 MVA or more in ten minutes, when any such increases or decreases occur more than once during any hour of the month, are required to take service under Rate FLS. The Companies' largest customers are served under these rate schedules. For KU, the proposed charges for Rates TODS, TODP, RTS, and FLS are shown on pages 9, 10, 11, and 12, respectively, of Schedule M-2.3 of KU's Filing Requirements. For LG&E, the proposed charges for Rates TODS, TODP, RTS, and FLS are shown on pages 8, 9, 10, and 11, respectively, of Schedule M-2.3-E of LG&E's Filing Requirements.

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

A. Yes. All four of these rates have a rate structure consisting of a Basic Service Charge, an Energy Charge, and a Maximum Load Charge comprising a Peak Demand Charge, an Intermediate Demand Charge, and a Base Demand Charge. The demand charges for these rates are billed based on a charge per kVA. The Peak Demand Charge applies to billing demands (maximum demands) that occur during the weekday hours ("Peak Demand Period") from 1:00 PM to 7:00 PM during the summer months of May through September ("summer peak months") and during the weekday hours from 6:00 AM to 12:00 Noon during winter months of October through April ("winter peak months"). The Intermediate Demand Charge applies to billing demands that occur during the weekday hours ("Intermediate Demand Period") from 10:00 AM to 10:00 PM during the summer peak months and from 6:00 AM to 10:00 PM during the winter peak months. The Base Demand Charge applies to the billing demands that occur at any time during the month.

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

A. Yes. The Companies must install sufficient generation resources to meet their peak demands. Peak demand conditions occur during the summer peak months and the winter peak months. Furthermore, peak conditions occur during hours between 6:00 AM and 10:00 PM but vary by season. The Companies must also install sufficient transmission and distribution facilities to deliver power to individual customers regardless of when they need it – during the peak or intermediate period or otherwise. Over the years, the Companies have structured the Peak Demand Charge and the Intermediate Demand Charge so that these charges would essentially provide recovery of generation fixed costs. The Base Demand Charge was structured so that the charge would basically provide recovery of transmission and distribution demand-related costs. Therefore, the Maximum Load Charge is essentially unbundled between generation fixed costs, which are recovered through the Peak and Intermediate Demand Charges, and transmission and distribution demand-related fixed costs, which are recovered through the Base Demand Charge.

Q. Are the Companies proposing any changes to the pricing structure of these rates?

A. No.

J. CURTAILABLE SERVICE RIDERS (CSR)

Q. Please describe the Companies' CSR schedules.

A. The Companies' CSR schedules provide credits to industrial or commercial customers who have agreed to interrupt a portion of their load when called upon by KU or LG&E. Curtailable customers receive a discount in the form of a credit to their demand charges in exchange for their willingness to receive curtailable service on a designated portion of their load. KU and LG&E have two CSR schedules: Curtailable Service Rider-1 (Rider CSR-1) and Curtailable Service-2 (Rider CSR-2). The Companies' CSR schedules are now all closed to new participation.

Q. Are KU and LG&E proposing changes to the CSR schedules?

A. No, other than a change to the LG&E CSR schedules to indicate that they are now closed to new participation. Specifically, the Companies are not proposing to change the CSR credits.

K. OUTDOOR SPORTS LIGHTING SERVICE (OSL)

Q. Please describe OSL.

A. OSL is a pilot rate introduced in the Stipulation and Recommendation in the Companies' 2016 rate case proceedings. The pilot rate is limited to 20 customers each for KU and LG&E on a first-come-first-served basis. The rate affords customers with lighting for outdoor sports fields to realize savings by operating their lighting equipment during off-peak hours. The rate consists of a Basic Service Charge, Energy Charge, and Base and Peak Demand Charges. KU currently serves four OSL-Secondary customers, and LG&E currently serves one OSL-Secondary customer. No customers take service under OSL-Primary.

Q. Are the Companies proposing to retain OSL?

A. Yes. The Companies are proposing to retain the rate schedule as a pilot program. By allowing sports fields the opportunity to avoid the Companies' system peaks and thereby avoid costs, the rate schedule appears to be operating effectively. Furthermore, the Companies' cost of service studies do not indicate that OSL is being subsidized by other customer classes. Therefore, the Companies propose to continue the rate as a pilot program. Because there are fewer than 20 customers currently taking service under OSL, the Companies propose to leave the maximum number of customers under the schedules at the current level of 20 customers on each system.

Q. Are the Companies proposing to adjust the Peak Period for the Summer Months for OSL?

A. Yes. To accommodate the management of sports lighting loads in late September, the

Companies are proposing to reduce the Peak Period during the summer peak months by one hour from the current peak hours of 1 PM – 7 PM to 1 PM – 6 PM.

Q. Are the Companies proposing to adjust the charges for OSL?

A. Yes. For OSL-Secondary, KU is proposing to decrease the energy charge from $0.03249 to $0.03210 per kWh, to decrease the Peak Demand Charge from $24.17 to $19.61 per kW and increase the Base Demand Charge from $2.02 to $2.93 per KW. These changes result in a net *decrease* in revenue for this rate of approximately 5.0% for KU. LG&E is proposing to decrease the energy charge for OSL-Secondary from $0.03441 to $0.03292 per kWh, to decrease the Peak Demand Charge from $26.57 to $23.14 per kW and decrease the Base Demand Charge from $3.44 to $3.38 per KW. These changes result in a net *decrease* in revenue for this rate of approximately 10.0% for LG&E. The detailed rate changes for OSL are shown on pages 16 and 17 of Schedule M-2.3 for KU and Schedule M-2.3-E for LG&E.

L. LIGHTING RATES

Q. Please provide an overview of the lighting rates currently offered by KU and LG&E.

A. KU and LG&E offer two rates that include the lighting fixture along with the delivered energy to operate the lights. Those two rates are Lighting Service (Rate LS) and Restricted Lighting Service (Rate RLS). Under Rates LS and RLS, the rates include the lighting fixtures along with the delivered energy to operate the lighting fixtures. Under these two rates, the lights can be fed by either overhead or underground service.

For lights fed from underground service, the cost of a non-wood pole is currently included in the rate. For lights fed from overhead service, the fixture is typically attached to an existing pole; therefore, the cost of the pole is not included in the rate. However, if a wood pole must be installed to provide service for an overhead light, then the customer would pay a separate monthly fee for that pole. KU and LG&E also offer two types of delivered energy service to customers who own their lighting fixtures or traffic signal and control equipment. Those two rates are Lighting Energy Service (Rate LE) and Traffic Energy Service (Rate TE).

Q. Please provide an overview of the proposed modifications to Rates LS and RLS.

A. In their 2016 and 2018 rate cases, KU and LG&E each introduced a number of light-emitting diode (LED) offerings. In the current rate case, KU is offering a new Victorian style LED offering, and LG&E is offering a new Victorian and a new London style LED offering. Under the proposed tariffs, the Companies will no longer be installing new non-LED lights. Accordingly, all non-LED lights would be moved from Rate LS to Rate RLS and thus be restricted. The Companies will continue to maintain the existing non-LED lights. However, if a non-LED fixture fails and the Companies no longer have replacement equipment in inventory to repair or replace the fixture, then the customer will be given a choice to have the light removed or to replace the non-LED light with an LED light. KU and LG&E will also continue to allow customers, at their option, to replace non-LED lights that are functioning (i.e., in good working order) with LED lights, but in those instances the customer would pay an LED Conversion Fee, as approved by the Commission in Case Nos. 2018-

00294 and 2018-00295.

Q. How were the charges for the LED fixtures determined?

A. For overhead lights, the proposed charge reflects the current cost to the Companies of the LED fixture, photocell and associated equipment (service wire, connectors, etc.), labor required for installation, and expected maintenance of the fixture. For underground lights, the Companies are proposing to break out the charges into a fixture charge and a pole charge. The fixture charge consists of the costs to the Companies of an LED fixture, photocell, labor required for installation, and expected maintenance of the fixture. Included in the pole charge is the cost to the Companies of the pole and associated equipment (base, connectors, etc.), labor to install the pole, and expected maintenance of the pole. The proposed charges for both underground and overhead fixtures are determined by calculating the monthly costs of the various types of fixtures using a standard carrying cost methodology that is consistent with how overall revenue requirements are determined in these proceedings. The cost of the fixtures reflects the installed cost of *new* fixtures, associated equipment, and maintenance. In calculating the charge for poles for underground lighting service, the annual cost was determined based on the embedded cost of an *existing* pole. In other words, it is assumed that an LED fixture will be installed on an existing pole, and the cost of the pole thus reflects the net depreciated cost of a pole on KU or LG&E's system. This is a reasonable assumption because for most LED conversions the existing pole will be used. The carrying charge calculations used to develop the rates for the fixtures assume an average service life of 25 years for the new LED offerings.

The calculation of the charges for the overhead and underground LED fixtures and the underground poles are shown in Exhibit WSS-4.

Q. Are the Companies proposing to lower the LED Conversion Fee that was authorized in the Companies last rate cases?

A. Yes. The LED Conversion Fee was approved by the Commission in Case Nos. 2018-00294 and 2018-00295. The Companies have updated the cost support for the Conversion Fee, as shown in Exhibit WSS-5. Based on the updated cost support, KU is proposing to reduce the monthly LED Conversion Fee from $6.03 to $5.01 per fixture per month, and LG&E is proposing to reduce the monthly LED Conversion Fee from $7.37 to $7.08 per fixture per month.[3]

Q. Are the Companies proposing to offer customers an option to pay the LED Conversion Fee as an up-front charge?

A. Yes. The LED Conversion Fee was implemented by the Commission in Case Nos. 2018-00294 and 2018-00295. The LED Conversion Fee was structured as a monthly charge that would be assessed over a period of five years. The Companies are proposing an option that would allow customers to make an up-front payment of the fee. The up-front payment reflects a discounted payment reflecting the discounted

[3] For accounting purposes, the Companies record a portion of the monthly conversion fees as revenue and a portion as a credit to net plant (viz., Account No. 108 – Accumulated Depreciation - Salvage). The portion credited to plant reflects the contribution that the conversion fees make toward the direct recovery of the stranded plant cost. Based on the current LED Conversion fee, for KU $2.07 of the fee is recorded as revenue and $3.96 is recorded as a credit to plant, and for LG&E, $2.56 of the fee is recorded as revenue and $4.81 is credited to plant. Based on the proposed LED Conversion Fee, for KU $1.72 of the fee would be recorded as revenue and $3.29 would be credited to plant, and for LG&E $2.46 of the fee would be recorded as revenue and $4.62 would be credited to plant. While both charges are shown in Schedule M-2.3 for KU and LG&E, only the revenue components of the conversion fees are included in test-year revenues.

present value charges based on KU and LG&E's weighted cost of capital. A KU customer that chooses to convert a restricted light to an LED light could elect to pay either $5.01 per month for 60 months or make an upfront payment of $197.16. An LG&E customer that chooses to convert a restricted light to an LED light could elect to pay either $7.08 per month for 60 months or make an upfront payment of $277.29.

Q. Please discuss the proposed rate changes to Rates LS, RLS, LE, and TE.

A. KU is not proposing an increase for Rate LS and RLS in total. However, KU is proposing changes to the monthly charges for individual fixtures and poles. For LED fixtures offered under Rate LS, KU is proposing to change the monthly charge for each fixture to reflect the current cost of the fixture. KU is also proposing to change the monthly charge for poles to reflect the current cost of each pole. This generally resulted in a reduction in the charges for LS LED fixtures and an increase in the charges for LS poles. Accounting for the effect of eliminating the ECR projects and the net reduction in revenue due to the decreases in the charges for LS fixtures and poles resulted in an increase of approximately 1.75% for each RLS fixture[4] to produce revenue neutral rates for LS and RLS customer class as a whole. The overall percentage increase in total revenue for LS and RLS, after accounting for revenues from the rate mechanisms (FAC, ECR, etc.) is 0.00% for KU.

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[4] The 1.75% increase in monthly unit charges for non-LED fixtures reflects the effect of transferring cost recovery of eliminated ECR projects into base rates and the impact of the proposed adjustments in the charges for poles and LED fixtures to current customers. While there is an increase in the monthly unit charge for non-LED fixtures, there is a corresponding reduction in the ECR mechanism revenues that would be billed. Of the 1.75% increase, 1.63% is related to the transfer of cost recovery of ECR revenue into base revenue.

LG&E is proposing an increase of 11.90% for Rate LS and RLS in total. For LED fixtures offered under Rate LS, LG&E is again proposing to change the monthly charge for each fixture to reflect the current cost of the fixture. LG&E is also proposing to change the monthly charge for poles to reflect the current cost of each pole. This generally resulted in an increase in the charges for LS LED fixtures and an increase in the charges for LS poles. Accounting for the effect of eliminating the ECR projects and the increases in charges for LED fixtures and poles, an increase of approximately 16.57% was required for each RLS fixture and pole[5] to produce an overall increase for Rate LS and RLS of 11.90%. Therefore, the overall percentage increase in total revenue for LS and RLS, after accounting for revenues from the rate mechanisms (FAC, ECR, etc.) is 11.90% for LG&E. The cost support for LED fixtures under LS and for poles is included in Exhibit WSS-4. The Companies are not proposing revenue increases for Rates LE and TE. However, the energy charge for the rates are modified to reflect the elimination of ECR projects. Changes in all lighting rates are shown in Schedule M-2.3 for KU and Schedule M-2.3-E for LG&E.

M. SOLAR SHARE

Q. Please describe KU and LG&E's Solar Share rates.

[5] The 16.57% increase in the monthly unit charges for non-LED fixtures reflects the effect of transferring cost recovery of eliminated ECR projects into base rates and the impact of the proposed adjustments in the charges for poles and LED fixtures to current customers. While there is an increase in the monthly unit charge for non-LED fixtures, there is a corresponding reduction in the ECR mechanism revenues that would be billed. Of the 16.57% increase, 4.53% is related to the transfer of cost recovery of ECR revenue into base revenue.

A. KU and LG&E offer an optional Solar Share Program Rider (Rider SSP) under which customers can purchase electric energy from solar panels jointly installed and maintained by the Companies. Rider SSP was filed by the Companies on August 2, 2016, in Case No. 2016-00274 and was approved by the Commission in its Order dated November 4, 2016. As originally filed, Rider SSP included three rate components: (1) an upfront subscription fee, (2) a monthly Solar Capacity Charge, and (3) monthly Solar Energy Credits for the energy produced by the Solar Share Facilities. On August 2, 2018, the Companies filed revised tariff sheets with the Commission to consolidate the upfront subscription fee with the Solar Capacity Charge and account for the effects of the federal Tax Cuts and Jobs Act and Kentucky House Bill 487. This change, which was accepted for filing by the Commission on August 28, 2018, resulted in the currently effective monthly Solar Capacity Charge of $5.55 per quarter-kW (nominal) subscribed.

Q. Are the Companies proposing modifications to KU and LG&E's Solar Share rates?

A. No.

Q. In the Companies' last rate cases, adjustments to miscellaneous revenues were made to ensure that costs related to the Solar Share Program were not shifted to other customers. Are the Companies making such adjustments for Solar Share in these proceedings?

A. Yes. The Solar Share Program was approved as a pilot program in Case No. 2016-00274. In that proceeding, the Companies made a commitment that the Solar Share Program would not result in increased charges to the Companies' other customers.

The Companies will continue to honor that commitment. To ensure that the costs of the Solar Share Program are not shifted to other customers, the Companies have imputed revenues to bring the class rate of return for Solar Share in the Companies' cost of service studies up to the overall rate of return on rate base proposed by the Companies in these proceedings. The Companies are also making imputed revenue adjustments for their Business Solar Programs. Specifically, for the Solar Share Programs, revenues of $295,846 are imputed for KU and revenues of $110,942 are imputed for LG&E. For the Business Solar Programs, revenues of $9,579 are imputed for KU and revenues of $9,378 are imputed for LG&E.

N. NET METERING

Q. Are the Companies proposing a new rate schedule for Net Metering Service to address recent amendments to KRS 278.465 – 278.467?

A. Yes. The Companies are proposing a new rate schedule called "NMS-2 Net Metering Service-2" that implements changes authorized by the amended statutes. NMS-2 will apply to new or non-grandfathered eligible customer-generators served by KU or LG&E on or after the date on which new rates from these proceedings take effect. Eligible electric generating facilities for which the Companies' written Application for Interconnection and Net Metering have been executed prior to the date new rates take effect will be grandfathered for 25 years under the Companies' current rate schedule for Net Metering Service, which will be renamed Net Metering Service – 1 (NMS-1). In my testimony, such customers who own such facilities are referred to as "*grandfathered net metering customers*." Customers to be served under NMS-2 are referred to as "*non-grandfathered*" or "*new*" net metering customers.

Q. What is a "customer-generator" according to the statutes?

A. Subparagraph (1) of KRS 278.465 defines an "eligible customer-generator" as follows:

> "Eligible customer-generator" means a customer of a retail electric supplier who owns and operates an electric generating facility that is located on the customer's premises, for the primary purpose of supplying all or part of the customer's own electricity requirements.

According to subparagraph (1)(b) of KRS 278.465, the eligible customer-generator would generate power from an "eligible electric generating facility", which must generate electricity from solar energy, wind energy, biomass or biogas energy, or hydro energy and cannot have a rated capacity above 45 kW. In the industry, an "eligible customer-generator" is also referred to as a "renewable distributed generation customer". I will use the terms "customer-generator" and "distributed generation customer" interchangeably to refer to an "eligible customer-generator" as defined in KRS 278.465.

Q. Does KRS 278.466 indicate that the utility shall compensate the customer-generator for the energy supplied to the grid?

A. Yes. Subparagraph (3) of KRS 278.466 states:

> A retail electric supplier serving an eligible customer-generator shall compensate that customer for all electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier, as measured by the standard kilowatt-hour metering prescribed in subsection (2) of this section. The rate to be

> used for such compensation shall be set by the commission using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier or generation and transmission cooperative on behalf of one (1) or more retail electric suppliers.

Q. How are the Companies proposing to compensate new customer-generators for energy they supply to the grid?

A. Under the Companies' proposed NMS-2 schedule, new customer-generators will be compensated for any net generation they supply to the grid (i.e., generation that exceeds their energy requirements during the month) at the avoided cost rate set forth in Rate B – Non-Time Differentiated Rate set for KU and LG&E's Small Capacity Cogeneration and Small Production Qualifying Facilities Rider (Rider SQF).

Q. Please provide some background on the Companies' Rider SQF.

A. SQF was implemented to comply with Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Both KU and LG&E were required to implement rate schedules under which the Companies would purchase energy from cogeneration and small power production qualifying facilities ("qualifying facilities"). These rate schedules were designed to apply to energy produced from cogeneration and from small power production from what are now characterized as "renewable resources". In its Order in Administrative Case No. 244, the Commission introduced 807 KAR 5:054 implementing Sections 201 and 210 of PURPA.[6] In compliance with those regulations, the Companies filed rate schedules applicable to energy

[6] *See The Adoption of a Small Power Production and Cogeneration Regulation Pursuant to Section 210 of Public Utility Regulatory Policies Act*, Admin. Case No. 244, Order (Ky. P.S.C. Feb. 10, 1981).

purchased from qualifying facilities. Rider SQF is applicable to energy purchased from qualifying facilities of 100 kW or less.

Q. What are *avoided energy costs*, and why is it appropriate to compensate customer-generators at a rate reflective of avoided costs?

A. The term *avoided energy costs* means the incremental costs of the energy that the utility would otherwise generate itself or purchase from another source if the customer-generator did not supply the energy. Whenever a distributed generation customer supplies electric energy to the grid, the utility can avoid generating the energy or purchasing the energy from another power supplier and thus avoid the incurring cost of the generating or purchasing the energy. Because of the intermittent and uncertain nature of the energy source (i.e., due the intermittent and uncertain availability of wind, sunlight, etc.), renewable distributed generating facilities identified in subparagraph (1)(b) of KRS 278.465 cannot be dispatched by the utility and cannot be supplied as firm capacity. Thus, only energy costs are avoided by the utility receiving electric energy from a customer-generator. Accordingly, the energy rates for energy purchases under SQF, which apply to qualifying facilities of 100 kW or less and are based on avoided energy costs, should also apply to the energy supplied to the grid by new customer-generators, as addressed in Subparagraph (3) of KRS 278.466. As specified in Subsection (5)(1)(a) of the 807 KAR 5:054 of the Commission's regulations, the Companies' avoided energy costs, as used to determine the purchase rates under SQF, are updated every two years. Using the avoided cost rate set forth in SQF will therefore place the compensation that new customer-generators receive under NMS-2 on the same non-discriminatory footing as the compensation that qualifying facilities receive under SQF.

Q. Will compensating customer-generators at avoided costs for the energy they supply to the grid put net metering on a more economically accurate footing for new customer-generators?

A. Yes. Under the older-style net metering service (such as the Companies' NMS-1, which will continue to be available for grandfathered customer-generators), customer-generators would be compensated for the power they put on the grid at a rate that is ***over four times*** the cost that would otherwise be incurred by the Companies to generate the power themselves or purchase the power. For example, KU is proposing an energy charge of $0.09950 per kWh for Rate RS. Therefore, under the older-style net metering service such as NMS-1, KU would effectively compensate customer-generators at a rate of $0.09950 per kWh plus amounts reflecting various cost-recovery riders (i.e., FAC, DSM, and ECR) for power they supply to the grid. However, the cost that KU would incur to generate this power itself or purchase the power is currently only $0.02173 per kWh.[7] Consequently, under the older-style net metering service such as NMS-1, customer-generators are compensated at a rate that is ***over four times*** the economic value of the energy. This creates the situation in which one group of customers, customer-generators, is being subsidized by other customers, non-customer-generators. This is particularly problematic in the case of

[7] $0.2173 per kWh is the current non-time-differentiated avoided cost rate in KU for Small Cogeneration and Small Power Production Qualifying Facilities (Standard Rate Rider SQF).

low-income customers who may not be able to afford to install solar panels or other types of distributed generation facilities. In those instances, lower-income customers, who may not be able to afford solar panels, would be required to subsidize higher-income customers who can afford to install solar panels. Compensating customer-generators at avoided costs for the power they put on the grid will eliminate these types of cross subsidies and will establish a more economically accurate framework for compensating net metering customers.

O. OTHER COST CONSIDERATIONS FOR SERVING CUSTOMER-GENERATORS

Q. Are there provisions of the net metering statutes that the Companies are choosing not to address at this time?

A. Yes. Subsection (5) of KRS 278.466 states:

> Using the ratemaking process provided by this chapter, each retail electric supplier shall be entitled to implement rates to recover from its eligible customer-generators all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators.

This subsection entitles electric energy suppliers subject to KRS 278.465 to .467 to implement new rate schedules that recover the cost of providing service to customer-generators "without regard for the rate structure for customers who are not eligible customer-generators".[8] The Companies are choosing not to develop cost-based rates designed specifically for distributed generation customers at this time, but the Companies plan to continue to evaluate the use of cost-based rate designs, such as four-part rates that include a customer charge, energy charge, peak demand charge, and base demand charge, to serve distributed generation customers.

Q. Why aren't the Companies implementing fully cost-based rates that recover fixed and demand-based costs?

A. By compensating net generation based on the rates set forth in SQF, the Companies believe that they are taking a major step toward addressing some of the subsidy issues related to serving distributed generation customers. The Companies' proposal represents a gradual movement toward implementing a cost-based pricing structure for customer-generators that will reduce *some of the subsidies* provided by non-distributed generation customers to distributed generation customers. The Companies' proposal is thus consistent with the ratemaking principles of rate continuity and gradualism. Before implementing fully cost-based rate structures, such as four-part rates, the Companies have also determined that it is necessary to gather more load data for distributed generation customers. Additionally, the Companies believe that more community and customer education and outreach are necessary before taking additional steps toward implementing fully cost-based rates – such as four-part rate designs – for distributed generation customers.

[8] KRS 278.466(5).

Q. What pricing structures have been utilized in other jurisdictions to reflect the cost of serving distributed generation customers?

A. There has been a movement toward implementing three- or four-part rates for distributed generation customers, consisting of a customer charge, energy charge and one or two demand charges. For example, in its Order in Docket No. 15-WSSE-115-RTS, the Kansas Corporation Commission approved a residential rate schedule[9] for Westar Energy Company (now called "Evergy Kansas Central, Inc."[10]) (hereinafter referred to as "Evergy") that required any residential customer adding behind-the-meter electric generation after October 28, 2015,[11] to take service under a three-part rate schedule consisting of a customer charge, energy charge and a seasonally differentiated demand charge. Evergy serves approximately 1.6 million customers in Kansas and Missouri. Evergy's Residential Standard Distributed Generation Rate (see Exhibit WSS-6) currently consists of the following rate components:

Basic Service Fee	$14.50 per month
Energy Charge	4.5840 ¢ per kWh
Demand Charge	
Winter Period	$3.00 per kW
Summer Period	$9.00 per kW

[9] Approval of the tariff was affirmed in Docket No. 18-WSEE-328-RTS after being considered in Docket No. 16-GIME-4030-GIE, which was an administrative case styled "In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers."

[10] In 2018, Westar Energy received regulatory approval to be merged with Great Plains Energy to form Evergy, Inc. Evergy serves approximately 1.6 million customers in Kansas and Missouri.

[11] The date applicable to new distributed generation was subsequently moved to October 1, 2018, in the Kansas Corporation Commission's Order in Docket No. 18-WSEE-328-RTS.

The demand charge in the rate helps prevent a customer with behind-the-meter generation from shifting fixed, and therefore unavoidable, demand-related capacity costs onto other residential customers. In its Order in Docket No. 16-GIME-403-GIE, the Kansas Corporation Commission stated:

> [T]he Commission finds the current two-part residential rate design [consisting of only a customer charge and energy charges] is problematic for utilities and residential private DG [distributed generation] customers because DG customers use the electric grid as a backup system resulting in their consuming less energy than non-DG customers, which results in DG customers not paying the same proportion of fixed costs as non-DG customers. The Commission finds DG customers are thus being subsidized by non-DG customers.[12]

For ease of reference, Kansas Corporation Commission's Order in Docket No. 16-GIME-403-GIE is attached hereto as Exhibit WSS-7. Challenges with serving distributed generation customers are generally recognized in the industry and utilities are beginning to develop rate designs such as Evergy's three-part rates or four-part rates to address the issue. Other utilities and regulatory commissions have also recognized the problem with the continued use of two-part rates consisting of only a customer charge and energy charge for serving distributed distribution customers. The New Mexico Public Regulation Staff has filed testimony in a number of proceedings pointing out problems with serving distributed generation customers under two-part

[12] *Final Order*, Docket No. 16-GIME-403-GIE dated September 21, 2017, at p.

rates.[13]

Q. KRS 278.466 addresses the recovery of fixed- and demand-based costs. Why is it important for utilities to have rates that provide for the recovery of these types of costs to serve customer-generators?

A. Serving distributed generation customers under two-part rate schedules such as Residential Service RS, General Service GS, and All Electric School Service AES creates a pricing environment in which customers who do not have their own electric generation facilities are forced to subsidize customers who operate their own behind-the-meter generating facilities. As will be explained, a two-part rate schedule consisting of a customer charge and an energy charge allows a customer-generator with solar panels, for example, to fall back on the utility when sunlight is not available and avoid paying the full cost of service. Therefore, serving distributed generation customers under a two-part rate consisting of only a customer charge and energy charge forces non-distributed generation customers to subsidize distributed generation customers. Because it accurately reflects cost of service, a four-part rate would ensure that distributed generation customers are not over-charged or under-charged for the service they receive. A four-part rate design would thus prevent customers who do not have electric generation facilities from subsidizing distributed generation customers.

Q. Do KU and LG&E have any four-part rate schedules?

[13] For example, testimony was filed by Southwest Public Service Company and the New Mexico Public Regulation Staff in Case No. 17-00255-UT on the issue.

A. Yes. The Companies have used four-part rates for decades for its large customers. Rates TODS, TODP, RTS, and FLS are four-part rates. Four-part rates are mandatory for all customers with loads greater than 250 kVA. The Companies require customers with demands between 50 kVA and 250 kVA to take service under Rate PS, which is a three-part rate consisting of a customer charge, energy charge and maximum demand charge.[14] A wide variety of customers take service under these rate schedules. Load factors of customers taking service under these rates range from less than 5% to almost 100%. To put this in perspective, a residential customer will typically have a load factor based on their maximum demand of between 15% to 30%. Therefore, there are customers taking service under these rates with load factors less than a typical residential customer.

Q. Why have residential and small commercial and industrial (C&I) customers traditionally not been served under rate schedules with demand charges?

A. The concept of demand rates was conceived in the 1890s by the British electrical engineer John Hopkinson.[15] It was not long afterwards that electric utilities began billing some their customers under demand-energy rates, which were often referred to as "Hopkinson Rates". Based on my research, the principal reason that residential and small C&I customers were not originally served under three- and four-part rates was

[14] The only exception to this is that all-electric schools taking service prior the KU system on or before July 1, 2011, were allowed to continue to be served under a two-part rate schedule. Except for this grandfathering provision, customers with demand greater than 50 kVA must be served under demand-based rates.

[15] See "Presidential Address to the Junior Engineering Society, 4th Nov., 1892, On the Cost of Electric Supply", *Original Papers by the Late John Hopkinson*, Vol 1 (1901), pp. 254-268.

the high cost of metering equipment required to measure a customer's maximum or peak period demands. Until recently, to implement a three-part rate required a relatively expensive demand meter (e.g., a reset demand meter), and to implement a four-part rate required the installation of special chart meters or paper tape meters, which were even more expensive than reset demand meters. (See photos in Exhibit WSS-8.) These types of meters were generally available during the very early years of the electric utility industry, but they were prohibitively expensive. Consequently, they were only used for the largest customers served by electric utilities. As early as 1915, some rate engineers were promoting demand and energy rates for *all* customers. For example, the electrical engineer Paul M. Lincoln had developed a relatively inexpensive thermal meter which he promoted for use in measuring customer's maximum demand.[16] Lincoln argued that his meter could eventually be used to implement demand rates for all types of customers, including residential customers. While the meter was relatively inexpensive, it proved not to be sufficiently accurate

[16] The meter was called the "Lincoln Demand Meter". See also, Paul M. Lincoln, "Rates and Rate Making", *Transactions of the American Institute of Electrical Engineers*, July to December 1915, at pp. 2279-2318. It is of historical interest that in responding to Lincoln's paper, the utility executive Louis R. Lee clearly described the basis for a four-part rate:

> [T]he idea of the demand charge is to cover fixed charges necessary to handle the demand both at power station in the distribution system and in service transformers. In the power station the portion of fixed cost which any individual customer should be charged with, would be based up his average demand during the peak load on the power plant. For the distribution system and service transformers, however, the amount which would be chargeable to the individual customer would depend upon his maximum demand regardless of the time of its occurrence. (Id., at p. 2354.)

for use in billing customers.[17] During the early history of the electric utility industry, the principal residential use of electric energy was for lighting. Electric appliances such as clothes irons, fans and refrigerators did not become prevalent until much later. Because customer loads for lighting were considered homogenous, demand metering was not considered necessary during the early years of the industry.[18] But as residential customers began to use a multitude of appliances, residential customer loads became more diverse and less homogeneous. Until the emergence of Advanced Metering Systems (AMS) and Advanced Metering Infrastructure (AMI), the implementation of demand rates on a wide scale for residential and small C&I customers was not considered practical. Over the past decade, a small but growing number of utilities have implemented demand rates for all their residential customers, not just new distributed generation customers as in Kansas.

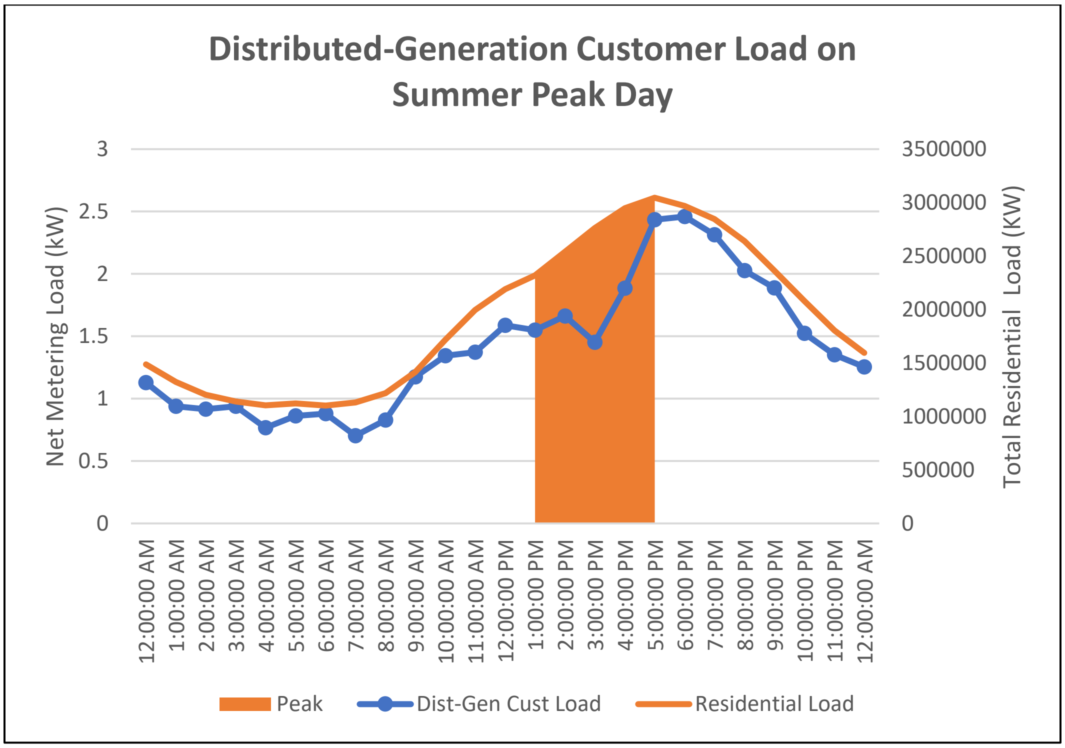
Q. Do customers with distributed generation facilities generally have different load characteristics than customers who do not own generation facilities?

A. Yes. Customers with distributed generation facilities typically have significantly different load characteristics and load shapes than customers that do not have distributed generation facilities. For example, customer-generators will have lower load factors than non-distributed generation customers. The following graph (GRAPH

[17] The meter design was eventually purchased by Sangamo Electric Company and was used in non-billing industrial applications until the 1960s.
[18] Id. at pp. 2319-2360.

3) compares the loads for a small sample of the Companies' residential customers[19] with solar panels to the loads for the residential rate class on a *summer* peak day:

GRAPH 3



As can be seen from this graph, loads for the distributed generation customers are depressed during the hours of the day when there is sufficient sunlight to operate the solar panels, but the graph shows a spike in the customer-generators' loads in the

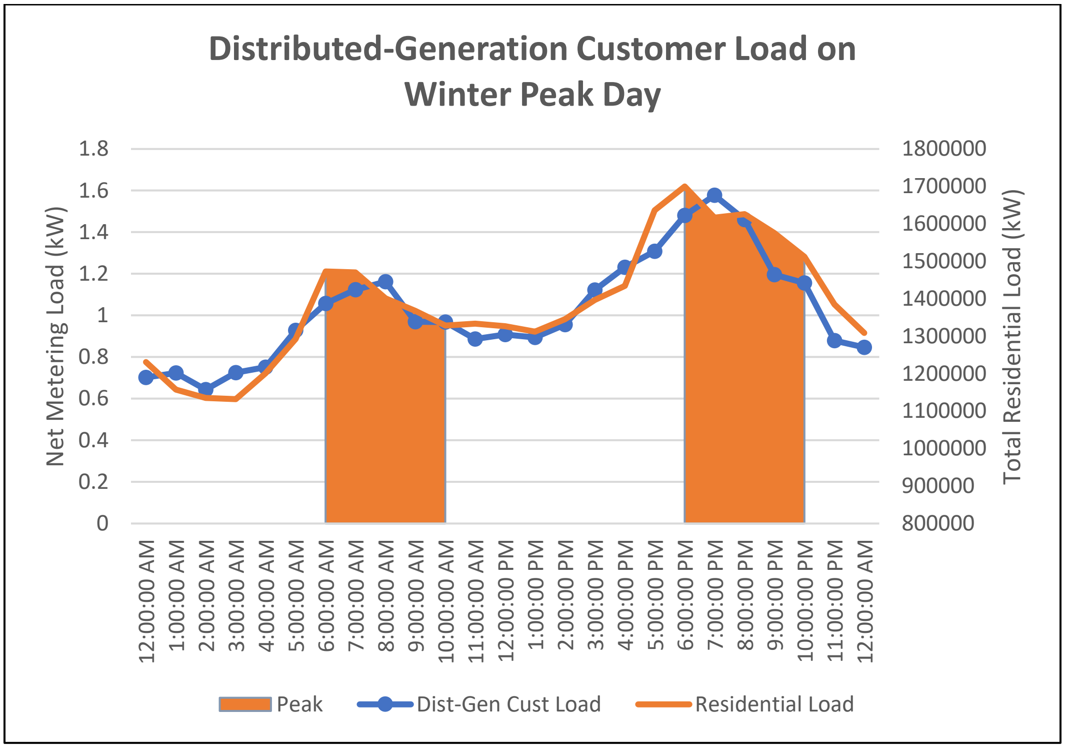
[19] The sample includes customer loads for which the Companies have MV90 telemetering data. There were 20 residential net metering customers served by KU and 15 net metering customers served by LG&E. The analysis of the data is intended to be illustrative. The Companies plan to collect more load data for net metering customers before evaluating four-part rates for distributed generation customers.

evening when the sunlight is no longer available for solar generation.[20] However, KU and LG&E must stand ready to deliver power to distributed generation customers when the load spikes in the evening. Thus, distributed generation facilities do not result in appreciable savings in generation, transmission, or distribution fixed costs. With a two-part rate, in which generation, transmission and distribution demand costs are recovered through a volumetric-based energy charge, the customer-generators realize reductions in their electric bills that are disproportionate to the savings created by the customer's solar generation. This results in other customers subsidizing distributed generation customers.

The following graph (GRAPH 4) compares the loads for the Companies' residential customers with solar panels to the loads for the residential rate class on a *winter* peak day:

[20] California utilities rely heavily on utility- and customer-owned solar power to meet peak demands. In mid-August, a heat wave in California resulted in rolling blackouts on two consecutive days. The problem came in the evening when solar generation dropped off. The rolling outages affected several hundred thousand customers starting around 6:30 PM on August 14 and 15, 2020. Once solar power provided to the grid fell below 6 percent of the load, grid operators were required to institute rolling blackouts. A spokesperson for the California Independent System Operator said, "The peak demand was steady in late hours, and we had thousands of megawatts of solar reducing their output as the sun set." *Forbes*, August 15, 2020.

GRAPH 4



As can be seen from this graph, on the winter peak day, the loads for residential distributed generation customers do not have an appreciably different pattern than the loads for the Companies' residential customers. KU and LG&E's combined system peak demand occurs during the hours from 6 AM to 10 AM during the morning and from 6 PM to 10 PM during the evening. During these hours, the customer-generators' solar panels are not operating at significant levels. Therefore, the Companies must have sufficient generation, transmission, and distribution capacity to serve customer-generators' loads during those hours. The distributed generation facilities do not appear to result in *any* fixed cost savings to the customers. But with a two-part rate in which fixed costs are recovered through a volumetric energy charge, the distributed generation customers are able to shift demand-related cost recovery to other customers without creating any fixed-cost savings.

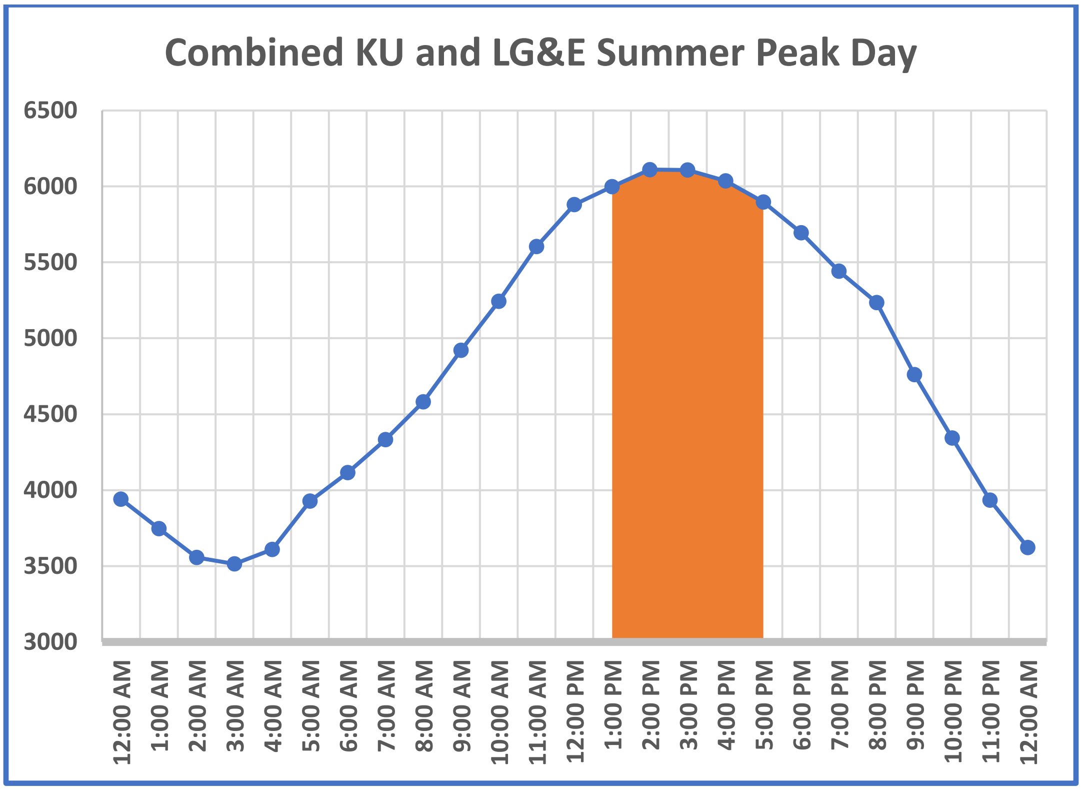
Q. Please describe the costs necessary to serve eligible customer-generators.

A. Earlier in my testimony, I discussed that an electric utility incurs three types (or "classifications") of costs to serve customers – namely, energy-related costs, demand-related costs, and customer-related costs. These same three types of costs are also incurred to serve customer-generators.

As explained earlier in my testimony, *energy-related costs* are the strictly variable expenses, such as fuel costs, that an electric utility incurs to supply the amount of energy measured in kilowatt-hours (kWh) that a customer uses. To the extent that a customer-generator produces energy from its own electric generation facilities, instead of purchasing the energy from the utility, the energy-related cost incurred by the utility to serve that customer is reduced or avoided.

Demand-related costs are costs related to the maximum load or kW demand placed on the utility system. An electric utility must install sufficient generation, transmission and distribution capacity to meet the maximum demand placed on the facilities. These costs are therefore demand related. For example, an electric utility must have sufficient generation capacity to serve its maximum system peak demand. The maximum system peak demand represents the aggregated load of all of its customers, effectively taking into consideration that while individual customers may have different load patterns, when they are all added together the aggregated loads result in a well-defined load shape for the system as a whole. Based on their combined system loads in MW, KU and LG&E's load pattern on a summer peak day is depicted below (GRAPH 5).

GRAPH 5



KU and LG&E must install sufficient generation and transmission capacity to meet the summer system peak demand that occurs between the hours of 1 PM to 5 PM during the summer months.

An integrated electric utility such as KU and LG&E must also have sufficient distribution capacity to serve its customers' loads. Unlike generation facilities, distribution facilities must be sized to meet the localized loads of individual customers served on the distribution system. For example, an electric utility must install sufficient secondary distribution capacity, transformer capacity, and service line capacity to serve a customer's individual maximum demand whenever it occurs. This is precisely the reason that distribution demand-related costs are allocated differently in the Companies' class cost of service studies than production and transmission costs, as discussed later in my testimony. Therefore, to the extent that a customer-generator can reduce the maximum demand placed on the system, these demand-related distribution costs can be reduced.

Customer-related costs are costs incurred to serve customers regardless of the quantity of electric energy (kWh) purchased or the peak demand requirements (kW) of the customers. As with any other customers, customer-related costs are incurred to serve customer-generators.

Q. How are *energy-related costs* impacted by customer generation?

A. The electric energy produced by a customer-generator allows an electric utility to avoid its *energy-related* costs. If a customer generates energy with any type of distributed generation technology, then the utility is not required to generate that energy to serve the customer. The utility's energy-related costs are thereby reduced. Thus, the customer-generator that reduces its energy should not pay for the energy-related costs. Furthermore, a customer-generator that generates more energy than the total amount of the customer-generator's own energy requirements, thereby resulting in *net generation*, allows the utility to further avoid its energy-related costs. The customer-generator should therefore be compensated for such net generation at a rate that reflects the utility's avoided energy costs. In other words, the customer-generator that generates net energy should receive a billing credit that reflects KU and LG&E's avoided energy costs as set forth in Rider SQF.

Q. How are *demand-related costs* impacted by customer generation?

A. If a customer-generator can consistently generate power at the time of the utility's system peak demand, then the utility will not incur demand-related generation costs to serve the customer. Specifically, if a customer-generator can generate power during KU and LG&E's peak period, as shown in GRAPH 5 above, the Companies do not need to have generation capacity to serve the customer-generator. Consequently, the customer-generator should only be assessed a generation demand charge during the Companies' peak periods. Likewise, if a customer-generator can reduce the maximum demand that is placed on the distribution system, the Companies are not required to install the distribution facilities for the reduced load. Therefore, if a customer-generator can reduce its maximum demand through self-generation, then the customer-generator should pay a lower distribution demand cost.

Q. Is it possible for customer-generators to reduce demand-related costs?

A. Yes, but the extent to which demand cost reductions can be realized depends on the distributed generation technology used by the customer. *<u>Not all distributed generation technologies create the same demand cost savings</u>*. For example, assume a customer-generator installs a combination of solar panels and battery storage. The combination of solar panels and battery storage can be managed to ensure that both peak-period demands and customer-maximum demands are reduced. This is not likely to be the case for a customer-generator who installs only solar panels. With solar panels, power is generated only when there is sufficient sunlight to produce power. If the solar panels are not producing power during the peak period, then no generation demand cost savings can be realized. These two examples underscore the difference in demand savings created by various distributed generation configurations and underscore the importance of including a demand charge in the pricing structure for distributed generation. With a pricing structure in which demand costs are recovered as an energy charge (per kWh charge), rather than as a demand charge (per kW charge), a technology configuration that includes only solar panels would receive the same pricing benefits as a technology configuration that includes both solar panels and battery storage, even though a combination of solar panels and battery storage can be managed to provide significantly higher demand cost savings. Recovering demand-related costs though a per-kWh charge overcompensates a customer-generator that installs solar panels but without battery storage.

Q. Can you provide a numerical example of how a customer-generator with solar panels, but no battery backup, is more costly to serve than a customer-generator with solar panels and managed battery storage?

A. Yes. Consider the example of a residential customer served by either KU or LG&E with a maximum demand of 10 kW during the summer and 20 kW during the winter. Suppose that during the summer, the customer has 7 kW of air-conditioning load and

3 kW of lighting, refrigeration, water heating, and other load, and that during the winter the customer has 17 kW of electric heating load and 3 kW of lighting, refrigeration, water hearing and other load. Assume further that the customer has 20 kW of solar panel capacity. During the summer months, it is likely that the solar panels are fully or partially operational during the KU and LG&E peak hours from 1:00 to 5:00 PM. Therefore, solar panels may result in a partial reduction in generation demand costs. However, during the evening hours, when the customer's solar panels are not generating power, the customer will still be operating air conditioning equipment and will be fully utilizing KU or LG&E's distribution system. Consequently, the customer's solar generation does not result in a reduction of the distribution capacity required to serve the customer. For this reason, the customer-generator should be assessed a charge that reflects the demand that the customer imposes on the distribution system.

During the winter, KU and LG&E's peaks typically occur during the hours of 6 AM to 10 AM in the morning and 6 PM to 10 PM in the evening. During those hours, it is less likely that the customer's solar panels are generating power. Therefore, KU and LG&E must have the generation, transmission, and distribution capacity necessary to serve the customer-generator's full load. Since the customer-generator cannot reduce demand during the peak period, the customer-generator should be assessed a charge that reflects the demand that the customer imposes on the generation, transmission, and distribution system.

Q. But what about a customer-generator who has installed solar panels and

managed battery storage?

A. Let us assume that the same customer has installed 40 kW of solar panels but has also installed lithium ion batteries with 20 kW maximum output and with the ability to store energy for several days. Then the customer can store electric energy in the batteries while the solar panels are operating but draw power from the batteries when there is insufficient sunlight to generate power from the solar panels. This customer can effectively reduce the demand imposed on the generation system during KU and LG&E's system peak periods and also reduce the maximum demand that the customer places on the Companies' distribution systems. Therefore, unlike a customer with only solar panels, this customer can fully reduce the production demand costs required to serve the customer and partially reduce the distribution costs incurred to serve the customer. Because the customer-generator with a combination of solar panels and managed battery storage can fully reduce demand during the peak period, along with reducing maximum demand during the month, the customer-generator should be assessed lower demand charges than a customer-generator with only solar panels. But this would not be the case if the customer is served under a two-part rate. With a two-part rate design, consisting of only a customer charge and an energy charge, there is no *economic* benefit for installing battery storage. With a two-part rate, the only benefit for adding battery storage is increased reliability.

Q. How are *customer-related costs* impacted by customer generation?

A. Customer-related costs are not impacted by customer generation. Customer-related costs are the costs related to connecting the customer to the system and include the cost of the meter, service line, the minimum distribution assets required to connect the customer to the grid, and meter reading and billing costs. These costs do not vary with the customer's energy usage or demand.

Q. Will the Companies be investigating these issues in the future?

A. Yes, that is their intention.

P. ELECTRIC VEHICLE CHARGING STATION RATES

Q. Do KU and LG&E currently offer public electric vehicle charging service?

A. Yes. KU and LG&E currently provide electric vehicle charging service to licensed electric vehicles from twenty Level 2 Charging Stations. Service is provided from these Level 2 Charging Stations under Electric Vehicle Charging Service Rate EVC, which was originally approved by the Commission in Case No. 2015-00355 and substantially modified in the Companies' last general rate case filings in Case Nos. 2018-00294 and 2018-00295.

Q. Are the Companies proposing any changes to the Level 2 charging service set forth in Rate EVC?

A. No.

Q. In the Companies' last rate cases, adjustments to miscellaneous revenues were made to ensure that costs related to Level 2 charging under Rate EV were not shifted to other customers. Are the Companies making such an adjustment for Level 2 charging service in these proceedings?

A. Yes. Level 2 Charging Service under Rate EV was approved as a pilot program in

Case No. 2015-00355. In that proceeding, the Companies made a commitment that the Level 2 charging service would not result in increased charges to the Companies' other customers. For Level 2 charging service offered under Rate EV, the Companies will continue to honor that commitment. To ensure that the cost of providing Level 2 charging service isn't shifted to other customers, the Companies have imputed revenues for Rate EV to bring the class rate of return for Rate EV in the Companies' cost of service studies up to the overall rate of return on rate base proposed by the Companies in these proceedings. Specifically, revenues of $48,431 are imputed for KU and revenues of $55,206 are imputed for LG&E.

Q. Are KU and LG&E proposing a new electric vehicle charging rate schedule in these proceedings?

A. Yes. The Companies are proposing a new rate schedule to provide Level 3 Charging Service, which is generally referred to as "*DC Fast Charging Service*". The new rate schedule for DC Fast Charging Service is called "EVC-FAST Electric Vehicle Fast Charging Service."

Q. Please describe the differences between Level 1, Level 2 and Level 3 Charging.

A. A ***Level 1 Charger*** is the most basic type of electric vehicle charger, which charges a vehicle from a standard 120V household outlet. A Level 1 charger can only provide about 4 to 5 miles of driving per hour, which for some drivers can be sufficient if the vehicle is charged through the night and if the vehicles are driven relatively short distances.

A ***Level 2 Charger*** charges a vehicle from a 240V outlet and will typically provide between 12 and 60 miles of range per hour. A 240V circuit is typically what is required for electric washing machines, dryers, and central air-conditioning units. As the mileage range of electric vehicles increases, it is anticipated that most residential customers with electric vehicles will install Level 2 Chargers. The electric vehicle charging service currently provided by KU and LG&E under Rate EV utilizes Level 2 Charging Technology.

A ***Level 3 Charger*** (or "DC Fast Charging Station") is a primary voltage charger that uses a direct current (DC) circuit to charge a plug-in electric vehicle. In comparison to the Companies' Level 2 stations, which provide charging at a rate of 7.2 kW, the DC Fast Charging Stations will be able to charge at a rate of 50 kW or greater (i.e., 50 kWh or greater per hour). A DC Fast Charging Station can provide 300 miles of range or more in about an hour, although charging speeds vary. Beginning in the second half of 2022, KU and LG&E plan to install DC Fast Charging Stations to provide service under Rate EVC-FAST. DC Fast Chargers are a key *enabling technology* for the adoption of electric vehicles.

Q. Are any costs of DC Fast Charging Stations included in revenue requirements in these proceedings?

A. No. All costs incurred to install and operate any DC Fast Charging Stations would be incurred beyond the end of the forecasted test year used in these proceedings. Therefore, revenue requirements in these proceedings do not include any costs of DC Fast Charging Stations. In these proceedings, the Companies are requesting approval for rates for service from DC Fast Charging Stations that the Companies plan to install beginning in the second half of 2022.

Q. Are there benefits to ratepayers from the adoption of electric vehicles?

A. Yes. The adoption of electric vehicles by residential and non-residential customers has an enormous potential to reduce the unit cost of providing electric service to electric utility customers. What is particularly compelling about the adoption of electric vehicles *from a utility customer's perspective* is that electric vehicle charging by customers typically takes place through the night, when electric utility loads are at their lowest levels. A residential customer who owns an electric vehicle will typically drive the vehicle during daytime hours and charge the vehicle at night. Since electric vehicles are typically connected to home charging stations during off-peak hours, increased numbers of electric vehicles will result in additional revenue but typically without creating the need to install new generation, transmission or even distribution capacity to serve the load. Consequently, increased electric vehicle ownership helps spread fixed generation and transmission costs over a larger number of sales, thus placing a downward pressure on the Companies' rates. Increasing electric vehicle charging sales provides benefits comparable to adding new industrial and commercial load from economic development efforts. Just as adding new large commercial and industrial loads allows KU and LG&E to spread fixed costs over a larger number of sales, additional electric vehicle charging will allow KU and LG&E to spread their fixed costs over a larger sales base.

Q. How does the adoption of electric vehicles in Kentucky compare to other states?

A. Kentucky ranks as a state with one of lowest numbers of electric vehicles in the country. According to data published by the United States Department of Energy, on a per capita basis, Kentucky had the sixth lowest number of electric vehicles registered in the state, ahead of only West Virginia, Mississippi, Arkansas, North Dakota, and Louisiana. In 2018, there were 1,240 electric vehicles registered in Kentucky, which corresponds to 27.75 electric vehicles registered for every 100,000 residents in Kentucky,[21] though this number appears to be growing.[22] Undoubtedly, there is a regional element to the adoption of electric vehicles, with the highest levels of adoption in California, Hawaii, Washington, and Oregon. However, there are also high levels of adoption in Georgia, Florida, Virginia, Texas, and North Carolina. For example, in 2018, there were 5 times more electric vehicles per 100,000 residents registered in Georgia than in Kentucky, and there were 4 times more electric vehicles per 100,000 residents registered in Florida than in Kentucky. Although the number of electric vehicles in Indiana cannot be considered high, there were almost twice the number of electric vehicles per 100,000 residents in Indiana as in Kentucky.

Q. What are the major impediments to the adoption of electric vehicles?

A. As I mentioned earlier, a plug-in electric vehicle is significantly less costly to operate than a conventional passenger vehicle. Therefore, it is useful to consider what the impediments are to the widespread adoption of electric vehicles. Based on my research, there are four major impediments to the adoption of plug-in electric vehicles,

[21] *See* Exhibit WSS-9.
[22] According to the Electric Power Research Institute (EPRI), the number of electric vehicles registered in Kentucky grew to 4,133 in June 2020.

three of which are being quickly addressed in the automotive industry.

The *first impediment* is the higher cost of a plug-in electric vehicle in comparison to a traditional vehicle powered by an internal combustion engine. However, over the past few years there has been a dramatic decrease in the cost difference between plug-in electric vehicles and conventional passenger vehicles. This reduction seems to have been in large part due to the engineering, manufacturing and marketing by Tesla, Inc. and other manufacturers. Based on the trends over the past several years, we can expect the price difference between plug-in electric vehicles and conventional vehicles to continue to decline as the economies of scale increase for electric vehicles.

The *second impediment* to the adoption of plug-in electric vehicles is the mileage range of the batteries. Again, this is an area in which the automotive industry is making dramatic improvements. For example, Tesla currently sells seven vehicles with a range of over 300 miles on a fully charged battery. Tesla's Model S Long Range Plus has a listed range of 391 miles. General Motors and Hyundai currently offer passenger vehicles with ranges that are over 250 miles. However, General Motors announced that it has developed a new electric vehicle battery with a range of up to 400 miles. A few years ago, it was difficult to find a plug-in electric vehicle with a range greater than 100 miles. It is reasonable to expect that the battery range will continue to improve.

The *third impediment* is the life of the battery. This is yet another area in which the automotive industry is making major improvements. The batteries in all electric vehicles sold in the United States are covered under warranties for at least 8 years or 100,000 miles. However, it is expected that electric vehicle batteries will last longer than 100,000 miles. For example, Tesla recently announced that a 1,000,000 mile battery is ready for production. Long-lived batteries along with charging ranges greater than 500 miles will likely be game changers for the adoption of plug-in electric vehicles.

The *fourth impediment* to the adoption of plug-in electric vehicles is the availability of fast charging stations. While technological advances in the automobile industry are addressing the first three impediments, from a public policy perspective, the availability of fast charging stations may represent the most formidable challenge to the adoption of plug-in electric vehicles. Even with battery ranges greater than 500 miles, there will be a public need for the availability of fast charging stations in order to facilitate the adoption of plug-in electric vehicles. Without the availability of fast charging stations, it is unlikely that passenger vehicle owners will be willing to purchase a plug-in vehicle without the prospects for charging their vehicles on long distance trips. Without more fast charging stations, electric vehicles will likely be limited in their use to commuter vehicles and will thus be demoted to use as a *secondary passenger vehicle*, forcing people to own a vehicle with an internal-combustion engine to serve as their *primary passenger vehicle*. Thus, fast charging stations are a *key enabling technology* that will allow people to purchase electric passenger vehicles.

Q. From a public policy perspective, why is it important for utilities to provide fast

charging service?

A. As mentioned earlier, there are enormous benefits to customers adopting electric vehicle technology. Electric vehicles are not only less costly to operate, the revenues generated by charging electric vehicles have the effect of lowering rates to other customers, by spreading utility fixed costs over a larger sales volume. Therefore, it is in ratepayers' interests for more people to use electric vehicles, providing ratepayer and public benefits that go well beyond the lower operating cost of electric vehicles. The need for electric utilities to install electric vehicle charging infrastructure is addressed in the report *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators* prepared by NARUC and sponsored by the United States Department of Energy (DOE), which explains:

> Many utilities around the country have begun to explore owning and operating EV charging stations to accelerate the growth of EVs and the corresponding growth in electric sales. Proponents of utility ownership present several arguments in favor: Most experts agree that current EV charging infrastructure will need to grow dramatically to cover the expected growth of EVs. This large "infrastructure gap" demands all hands on deck, including participation of utilities. Furthermore, <u>*widespread charging infrastructure is a prerequisite for many consumers to consider purchasing an EV*</u>, but it is difficult for EVs to be profitable without high usage from many EVs on the road. (*Id*., at p. 20. Emphasis supplied.)

According to this assessment, electric utilities will have to serve as providers of fast charging service until the number of electric vehicles on the roads make it feasible for private industry such as filling stations along interstates and highways like Pilot, Flying J, Loves, TA, RaceTrac, Murphy USA, and others to begin installing DC Fast Charging ports in larger numbers.

Q. Nationally, is there a correlation between the number of DC Fast Charging Ports and the number of plug-in electric vehicles owned?

A. Yes. There is a 98.7% correlation between the number of DC Fast Charging Ports and electric vehicles in a state. As can be seen from the graph shown in Exhibit WSS-10, the relationship is essentially linear. While it is impossible to prove causality from this analysis, the relationship does strongly suggest that DC Fast Charging Stations are an essential enabling technology for the adoption of plug-in electric vehicles.

Q. Do other utilities in our region offer DC Fast Charging Service?

A. Yes. Georgia Power currently owns and operates 39 DC Fast Charging stations. In June 2020, the Governor of Florida, Ron DeSantis, signed a directive for the Florida Public Service Commission to encourage utilities to develop electric charging stations along state highways. In July, Florida announced that 34 DC Fast Charging stations would be added along Interstate 95, Interstate 4, Interstate 75, Interstate 275, and Interstate 295.

Q. Please describe the proposed pricing structure for DC Fast Charging Service.

A. KU and LG&E are proposing to charge $0.25 per kWh for charging service under Rate EVC-FAST.

Q. How does this rate compare to the average rate for Level 2 charging service that the Companies currently charge under Rate EVC?

A. The Level 2 charging service rate under Rate EVC has a different pricing structure than what the Company is proposing for DC Fast Charging Service. Under Rate EVC, which was approved in the Companies' last rate cases, KU and LG&E charge a fee of $0.75 for the first hour of charging service and $1.00 for all additional hours during the charging session, plus appropriate taxes and fees. On average this is equivalent to $0.20 per kWh after taxes and fees. A recent study has found that the majority of respondents who have an electric vehicle or are considering purchasing one are willing to pay 25% more for fast charging in relation to Level 2 charging service provided under Rate EVC.[23] Therefore, in the industry, the charge for DC Fast Charging Service (Level 3 service) is typically higher than the charge for Level 2 charging service.

Q. How does the charge for service under the Companies' proposed Rate EVC-FAST compare to the DC Fast Charging Service offered by other utilities?

A. Although I have not performed an exhaustive review of all DC Fast Charging rates charged by utilities, several electric utilities providing service in Eastern United States (i.e., east of the Mississippi River) offer DC Fast Charging Service. The following table (TABLE 4) summarizes the charges per kWh for the utilities that I am aware of in Eastern United States that provide DC Fast Charging Service:

[23] See https://www.esource.com/429201ebtf/ev-charging-and-pricing-what-are-consumers-willing-pay, dated September 20, 2020.

TABLE 4

Utility	DC Fast Charging Rate
Baltimore Gas and Electric Company (BG&E)	$0.255 to $0.34 per kWh *
Duke Energy Carolinas	$0.236 per kWh **
Florida Power & Light (FPL)	$0.30 per kWh
Georgia Power Company	$0.30 per kWh ***
Potomac Electric Power Company (PEPCO)	$0.255 to $0.34 per kWh

* Customers with 5 or more vehicles operating in the utility's service territory are eligible for a 25% discount.
** Rate is adjusted quarterly to reflect the average price charged in the service territory.
*** Georgia Power charges $0.25 per hour, which is equivalent to approximately $0.30 per kWH for charging at its DC Fast Charging Stations.

As seen in this table, KU and LG&E's proposed charge for DC Fast Charging Service is in line with what is being charged by these other utilities.

Q. Based on your review of the filings submitted to state regulatory commissions by these utilities, were these DC Fast Charging rates supported by a cost analysis?

A. No. In developing the rates, the rate filings reflected market considerations rather than costs. Due to the uncertainty regarding future usage of DC Fast Charging Service any such cost analysis would be speculative. As more data is collected over time, a better picture of the actual unit cost of providing this service will emerge. But regardless, as discussed earlier, because of the benefits that the availability of fast charging stations provide as an enabling technology, it is important that more fast charging stations are available for public use. It is important to recognize that KU and LG&E are not trying to compete with third-party providers of DC Fast Charging service, and the Companies are not trying to undercut other providers by providing a below market price for fast charging service. More fast charging stations are needed to enable people to purchase electric vehicles. A thriving market for fast charging service will enable more customers to drive electric vehicles and thereby benefit KU and LG&E's existing customers by putting downward pressure on electric rates.

Q. You mentioned earlier that adjustments to miscellaneous revenues are being made to ensure that costs related to Level 2 charging under Rate EVC are not shifted to other customers. Are similar adjustments being made for DC Fast Charging Service?

A. No, nor are such adjustments necessary in these proceedings. As mentioned earlier, there are no costs related to the DC Fast Charging in test-year revenue requirements. Because test year revenue requirements do not include costs related to the DC Fast Charging Service, such an adjustment is neither necessary nor possible. The revenue requirement treatment of future investments in DC Fast Charging Stations will be addressed in subsequent rate proceedings. In these proceedings, the Companies are requesting approval of rates for DC Fast Charging Service that will be available to the public beginning during the second half of 2022. Consequently, none of the costs for this service is included in test year revenue requirements in these proceeding.

Q. Are the Companies proposing any changes to Electric Vehicle Supply Equipment Rate EVSE and EVSE-R?

A. Yes. Under Electric Vehicle Supply Equipment – Rider (Rider EVSE-R), the Companies provide charging stations behind the customers' meters which can be used by the customers to charge electric vehicles. Under Rider EVSE-R, the customer is responsible for providing the electric energy for the charging station and the Companies bill the customers a monthly fixed charge for the use of the charging station. Pursuant to Rate EVSE, the Companies provide an unmetered charging station which can be used by customers to charge electric vehicles. Under this rate schedule, the Companies provide the energy for the charging station, the cost of which is bundled into the monthly fixed charge. The Companies are proposing to add an additional charging unit option to the EVSE and EVSE-R tariff. The new charging unit is a basic non-networked charger that is preferred by some customers. The addition of this unit is not meant to compete with or replace the existing charging unit, but to supplement the options available to KU and LG&E's customers. Cost Support for the new EVSE and EVSE-R rates are shown in Exhibit WSS-11.

Q. REDUNDANT CAPACITY (RIDER RC)

Q. Please describe the Companies' Redundant Capacity rider.

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

Q. How is a customer charged for redundant capacity?

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

Q. What changes are the Companies proposing to the Redundant Capacity charges?

A. KU is proposing to decrease the demand charge for primary voltage customers from \$0.99 to \$0.92 per kW per month and to increase the charge from \$1.16 to \$1.36 per kW per month for secondary voltage customers. LG&E is proposing to decrease the demand charge for primary voltage customers from $1.41 to $1.31 per kW per month and to increase the charge from $1.84 to $1.93 per kW per month for secondary voltage customers. The cost support for the proposed redundant capacity charges is included in Exhibit WSS-12.

IV. GAS RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE GAS REVENUE INCREASE

Q. Please summarize your recommendations for allocating the gas revenue increase to the classes of service?

A. LG&E is proposing an overall revenue increase of $29,988,054 for its gas line of business, which corresponds to an 8.34% increase. LG&E is also proposing changes to other miscellaneous charges which result in changes to other operating revenue. Accounting for changes in other operating revenue results in increases in revenues from sales to ultimate customers of $29,979,285 (or 8.37%) for LG&E's gas operations. (See Schedule M 2.1-G in LG&E's Filing Requirements.)

I relied on the results of the gas cost-of-service study to develop my recommendations for allocating the gas revenue increase to the classes of service. As seen in the table below (TABLE 5), the class rates of return for As-Available Gas Service (Rate AAGS) and Firm Transportation Service (Rate FT) are significantly lower than for the other rate classes. I am recommending the elimination of 25% of the subsidies for Rates Residential Gas Service (RGS), AAGS, and FT. Because of its high rate of return, I am not recommending an increase for Rate IGS. Rate CGS is adjusted to collect the residual increase required to yield the overall increase. Specifically, as shown on Schedule M-2.1-G, I am recommending revenue increases of 9.37% for Rate RGS, 4.86% for Rate CGS, 26.09% for Rate AAGS, 39.75% for Rate FT, and no increase for Rate IGS.

It should be noted, however, that the percentage increase for Rate FT is somewhat misleading. The revenues for Rates RGS, CGS, IGS, and AAGS include recovery of the cost of the natural gas (the commodity), but Rate FT is a transportation-only service. Therefore, the recovery of the cost of the natural gas is not included in Rate FT revenues, which inflates the percentage increase for this class. If a proxy price of $3.42 per Mcf is assumed as the cost that Rate FT customers pay for natural gas, which reflects LG&E's average Gas Supply Cost Component during the test year, the effective increase that Rate FT customers would see in their total natural gas costs due to LG&E's proposed rate increase would only be 5.56%, which is not significantly higher than the increase that LG&E is proposing for Rate CGS. A comparison of the rate of return at current rates and the percentage revenue increase (decrease) proposed for each rate class is shown below in TABLE 5:

TABLE 5

Rate Class	Rate of Retun On Rate Base	Customer Increase in Cost of Gas *	Rate of Return On Rate Base After Increase
Residential Service Rate RGS	4.62%	9.37%	6.87%
Commercial Service Rate CGS	7.56%	4.86%	9.08%
Industrial Service Rate IGS	13.70%	0.00%	13.69%
As Available Gas Service Rate AAGS	-3.24%	26.09%	0.98%
Firm Transportation Service Rate FT	-1.75%	5.56%	2.10%
Total	5.10%	7.58%	7.23%

* The increase shown for Rate FT reflects a proxy price for the customer's natural gas of $3.42 per Mcf.

The rates of return for each rate class are shown in Exhibit WSS-13, and the revenue increases necessary to eliminate 25% of the subsidies for Rates RGS, FT and AAGS are calculated in Exhibit WSS-14.

Q. Is LG&E proposing to eliminate all subsidies?

A. No. As mentioned above, LG&E's proposal is to eliminate 25% of the subsidies for Rates FT, AAGS, and RGS. This approach moderates the large increase that would otherwise be required to bring the rates of return for Rates FT, AAGS, and RGS to the proposed overall rate of return.

Q. Has Rate FT increased significantly since it was first introduced?

A. No. Rate FT has increased very little since it was first introduced in 1995. Rate FT replaced a similar service called Rate T, which was introduced in 1988. The distribution charge for Rate T was $0.43 per Mcf when it was first introduced in

1988.[24] Rate T was replaced with Rate FT in 1995, but the distribution charge of $0.43 per Mcf remained the same.[25] Rate FT was not increased until July 1, 2015, when the charge was raised from $0.43 per Mcf to $0.4302 per Mcf.[26] Rate FT was increased again on July 1, 2017, from $0.4302 per Mcf to $0.4440 per Mcf.[27] The distribution charge was restructured as a demand/commodity rate in Case No. 2018-00295; however, the modification in that proceeding was designed to be revenue neutral. Therefore, during a period of over 32 years, the distribution charge for Rate FT (or its predecessor, Rate T) has only increased a *total* of 3.26%.

Q. What is creating the need for rate increases for Rates FT and AAGS?

A. As discussed in detail in Mr. Bellar's testimony, LG&E obtained approval from the Commission to modernize its gas transmission system. This Transmission Modernization Program ("TMP") and other modifications to LG&E's gas transmission pipelines, such as the planned modification to the Western Kentucky A and B pipelines, represent a commitment on the part of LG&E to invest in the replacement of aging gas transmission infrastructure. Prior to these transmission projects, LG&E had focused primarily on upgrading its distribution infrastructure. The investment that LG&E made to replace distribution infrastructure did not have a

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[24] Rate T was implemented in 1988 pursuant to the Commission's Order in Case No. 10064 (Ky. P.S.C. Jul. 1, 1988).
[25] In 1995, Rate FT replaced Rate T, which also included a distribution charge of $0.43. *See The Tariff Filing of Louisville Gas and Electric Company to Modify Firm Transportation Service Tariff*, Case No. 95-037, Order (Ky. P.S.C. Jun. 27, 1995).
[26] Case No. 2014-00372, Order (Ky. P.S.C. Jun. 30, 2015).
[27] Case No. 2016-00371, Order (Ky. P.S.C. Jun. 29, 2017).

major impact on the cost of providing service to customers taking service under Rates FT and AAGS. Customers served under Rates FT and AAGS are allocated relatively little of the cost of distribution infrastructure. This is not the case with transmission infrastructure. Because transmission costs make up a significantly larger portion of the total cost of service to Rate FT and Rate AAGS customers, TMP and other modifications to LG&E's gas transmission system have increased the cost of service to these two rate classes.

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

A. Yes. Rate VFD is not broken out in the cost-of-service study but is included with Rate RGS. Distributed Generation Gas Service (Rate DGGS) is a rate class that serves a small number of customers. It is a demand/commodity rate that is derived from unit costs from the cost-of-service study for Rate IGS. Rate DGGS is not broken out in the cost-of-service study but is included in Rate IGS in the study, as is the Companies' special contract with LG&E to provide gas sales service to the Mill Creek Generating Station. Local Gas Delivery Service (Rate LGDS) is a rate for the transportation of locally produced natural gas through LG&E's delivery system. Rate LGDS has the same rate structure and unit charges as Rate FT. There are currently no customers served under Rate LGDS.

Substitute Gas Sales Service (Rate SGSS) is a rate available to serve customers that desire substitute gas sales service from LG&E. It is a demand/commodity rate that is derived from unit costs from the cost-of-service study based on either Rate CGS or Rate IGS, as applicable. One commercial customer is served under Rate SGSS.

Therefore, Rate SGSS is not broken out separately in the cost-of-service study but is included in Rate CGS.

Q. Have you prepared an exhibit showing the proposed gas revenue increase for each rate schedule?

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

B. ELIMINATION OF GAS LINE TRACKER PROGRAMS

Q. Is LG&E proposing to eliminate certain Gas Line Tracker (GLT) projects?

A. Yes. LG&E is proposing to eliminate the Main Replacements portion of the Leak Mitigation Project, the Aldyl-A Mains and Services Replacement Project, and the Steel Customer Service Lines and Targeted Removal of County Loops and Steel Curbed Services Program ("Steel Services Program"), and Transmission Modernization Program ("TMP"). Except for the Steel Services Program, all work on the eliminated projects has been or will be completed before to the end of the test year. The Steel Service Program and the Transmission Modernization Program were only authorized for GLT recovery for a period of five years, which corresponds to the end of the test year.

Q. Will the costs of these eliminated GLT projects be recovered through base rates instead of the GLT?

A. Yes. The impact of the elimination of these programs are also shown in Schedule M-

2.3-G. Specifically, on page 1 of this Schedule, the column labeled "GLT Mechanism Adjustment to Reflect GLT Project Elimination" reflects the amount of GLT Mechanism revenue transferred to base rates. This adjustment *does not* alter total revenue, but simply represents the removal of GLT costs for the eliminated projects from the GLT mechanism into base rate recovery. This adjustment is revenue neutral. The supporting details for each rate class are shown on pages 2 through 11 of Schedule M-2.3-G.

C. RESIDENTIAL GAS SERVICE (RATE RGS)

Q. Please provide a brief description of Rate RGS.

A. Rate RGS is the standard gas rate schedule available to single-family residential service. Approximately 301,000 residential customers are served under this rate schedule. Rate RGS consists of a Basic Service Charge, Distribution Charge and Gas Supply Cost Component.

Q. What are the charges that LG&E is proposing for Rate RGS?

A. LG&E is proposing to increase the Basic Service Charge from $0.65 per day to $0.78 per day. The Company is also proposing to increase the Distribution Charge from $0.36782 per Ccf to $0.48398 per Ccf. LG&E is proposing the same charges for Volunteer Fire Department Service (Rate VFD).

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

A. LG&E is proposing a Basic Service Charge that moves the Basic Service Charge towards the customer-related costs from the cost-of-service study. As will be explained in greater detail later in my testimony regarding the gas cost-of-service study, the methodology that is used to classify costs as customer-related corresponds to the methodology that has been accepted by the Commission in prior rate case orders.

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

A. Yes. Exhibit WSS-15 shows the calculation of the unit customer cost and distribution delivery cost. From this exhibit, the customer cost is calculated to be $0.98 per customer per day, and the distribution delivery cost is $0.37070 per Ccf. LG&E's proposed Basic Service Charge of $0.78 is approximately 79.6% of the unit customer-related cost from the cost-of-service study. LG&E is proposing an increase in the Basic Service Charge of approximately 25%, which reflects a gradual movement of the charge towards cost of service.

D. COMMERCIAL GAS SERVICE (RATE CGS)

Q. Please provide a brief description of Rate CGS.

A. Rate CGS is the standard gas rate schedule available to commercial customers for gas sales service. Approximately 25,700 commercial customers are served under this rate schedule. Rate CGS consists of a Basic Service Charge, Distribution Charge and Gas Supply Cost Component. The Basic Service Charge is differentiated between customers who do not have a meter with a capacity equal to or greater than 5,000 cubic feet per hour (cf/hr) and customers who do have at least one meter with a capacity equal to or greater than 5,000 cf/hr.

Q. What are the charges that LG&E is proposing for Rate CGS?

A. LG&E is proposing to increase the Basic Service Charge from $1.97 per day to $2.30 per day for customers who do not have a meter with a capacity equal to or greater than 5,000 cf/hr and to increase the charge from $9.37 per day to $11.00 per day for customers who do have at least one meter with a capacity equal to or greater than 5,000 cf/hr. LG&E is proposing to increase the Distribution Charge from $0.30670 to $0.37688 per Ccf for on-peak usage and from $0.25670 to $0.32688 per Ccf for off-peak usage.

E. INDUSTRIAL GAS SERVICE (RATE IGS)

Q. Please provide a brief description of Rate IGS.

A. Rate IGS is the standard gas rate schedule available to industrial customers for gas sales service. Approximately 200 industrial customers are served under this rate schedule. Rate IGS consists of a Basic Service Charge, Distribution Charge and Gas Supply Cost Component. The Basic Service Charge is differentiated on the same basis as Rate CGS.

Q. What are the charges that LG&E is proposing for Rate IGS?

A. LG&E is not proposing a revenue increase for Rate IGS. However, Distribution Cost Components of Rate IGS are being adjusted to reflect the elimination of certain GLT projects and the transfer of cost recovery of the GLT project costs to base rates. To reflect the elimination of the GLT projects, LG&E is proposing to increase the Distribution Charge from $0.21929 to $0.27023 per Ccf for on-peak usage and from $0.16929 to $0.22023 per Ccf for off-peak usage. Again, this change is revenue neutral because there will be a corresponding reduction in the GLT.

F. AS AVAILABLE GAS SERVICE (RATE AAGS)

Q. Please provide a brief description of Rate AAGS.

A. Rate AAGS is the rate schedule available to commercial and industrial customers that agree to take gas sales service on a non-firm basis. There are only three customers on this rate schedule. Rate AAGS consists of a Basic Service Charge, Distribution Charge and Gas Supply Cost Component.

Q. Is LG&E proposing changes to Rate AAGS?

A. Yes. LG&E is proposing to increase the Basic Service Charge from $500.00 per month to $630.00 per month and to increase the Distribution Charge from $1.0644 to $2.0168 per Mcf.

G. FIRM TRANSPORTATION SERVICE (RATE FT)

Q. Please provide a brief description of Rate FT.

A. Rate FT is the standard gas rate schedule available to large commercial and industrial customers for firm gas transportation service. It is generally available to customers who use at least 50 Mcf per day at each delivery point. Rate FT currently includes an Administrative Charge of $550.00 per delivery point per month, a Basic Service

Charge of $750.00 per delivery point per month, a Distribution Charge of $0.0380 per Mcf, and a Demand Charge of $4.89 per Mcf of billing demand per month. The Basic Service Charge is applied to each customer receipt point. The Demand Charge is applied to the customer's monthly billing demand, which is the greater of the Maximum Daily Quantity (MDQ) or the highest daily volume of gas delivered to the delivery point during the current or preceding 11 monthly billing periods. The Distribution Charge is applied to the volumes of gas (Mcf) delivered to the customer at its facility. LG&E's largest gas customers receive service under this rate schedule.

Q. Is LG&E proposing changes to Rate FT?

A. Yes. LG&E is proposing to increase the Distribution Charge to $0.0456 per Mcf and the Demand Charge to $7.78 per Mcf of billing demand per month.

H. SUBSTITUTE GAS SALES SERVICE (RATE SGSS)

Q. Please describe Rate SGSS.

A. Rate SGSS is a standard rate schedule that provides substitute gas sales service for any customer who desires to receive firm sales service from LG&E in addition to gas received from other sources with which the customer is physically connected. This rate therefore applies to customers who normally receive gas supply directly from an interstate pipeline, another local distribution company, or a local producer but desire to rely on LG&E as an alternative or substitute supplier of natural gas.

Q. Please describe the proposed charges for Rate SGSS.

A. For commercial customers served under Rate SGSS, LG&E is proposing a Basic

Service Charge of $335.00 per month, a Demand Charge of $7.54 per Mcf of Monthly Billing Demand, and a Distribution Charge of $0.4106 per Mcf. The increase in the revenue for this class corresponds approximately to the increase for Rate CGS. One commercial customer takes service under Rate SGSS.

For industrial customers served under Rate SGSS, LG&E is proposing a Basic Service Charge of $750.00 per month, a Demand Charge of $10.89 per Mcf of Monthly Billing Demand, and a Distribution Charge of $0.3100 per Mcf. Currently, no industrial customers take service under Rate SGSS.

I. LOCAL GAS DELIVERY SERVICE (RATE LGDS)

Q. Please describe Rate LGDS.

A. Rate LGDS is a rate schedule that is available to parties who contract with LG&E to provide firm transportation service of locally produced gas. Currently, there are no customers served under Rate LGDS.

Q. Please describe the rate components for Rate LGDS and cost basis for the charges.

A. Rate LGDS currently includes an Administrative Charge of $550.00 per month, Basic Service Charge of $750.00 per month, a Demand Charge of $4.89 per Mcf, and a Distribution Charge of $0.0380 per Mcf. The Administrative Charge and Basic Service Charge are applied to each customer receipt point. The Demand Charge is applied to the customer’s monthly billing demand, which is the greater of the Maximum Daily Quantity (MDQ) or the highest daily volume of gas delivered to the delivery point during the current or preceding 11 monthly billing periods. The Distribution Charge is applied to the net nominated volumes of gas (Mcf) at the delivery point. LG&E is proposing the same charges for Rate LGDS as Rate FT as previously described because the type of transportation service provided under these two rate schedules is essentially similar. LG&E is proposing to increase the Distribution Charge to $0.0456 per Mcf and the Demand Charge to $7.78 per Mcf of billing demand per month.

J. DISTRIBUTED GENERATION GAS SERVICE (RATE DGGS)

Q. Please describe Rate DGGS.

A. Rate DGGS is a rate schedule that is available to parties with customer-owned electric generation facilities who require natural gas service.

Q. Is LG&E proposing any modifications to the charges for Rate DGGS?

A. Yes. LG&E is proposing to increase the Distribution Charge from $0.2992 to $0.3100 per Mcf and to decrease the Demand Charge from $10.8978 to $10.89.

VI. MISCELLANEOUS SERVICE CHARGES

A. POLE AND STRUCTURE ATTACHMENT CHARGES (RATE PSA)

Q. Are KU and LG&E proposing to increase the pole and structure attachment charges set forth in Rate PSA?

A. No. The Companies are proposing to maintain the pole attachment charge applicable to cable television operators and telecommunication carriers at the current annual levels of $7.25 per wireline attachment, $0.81 per linear foot of duct, and $36.25 per wireless facility located on the top of a pole. Of the three charges, the wireline attachment charge has by far the greatest utilization. Currently, there are minimal wireless and duct attachments.

Q. Did you validate the reasonableness of the current wireline attachment charge?

A. Yes. When I calculated the wireline attachment charge using forecasted costs based on a revenue requirement reflecting net cost plant (net cost rate base), the analysis resulted in a unit cost for KU and LG&E of $7.84 per attachment. Because the current charge reasonably reflects the updated cost based on forecasted net plant, the Companies decided not to propose a change in the rates at this time.

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

A. In its Order in Administrative Case No. 251, the Commission prescribed a methodology for determining the attachment charges. The calculations set forth in Exhibit WSS-16 follow the guidelines established in Administrative Case No. 251. In this exhibit, the weighted average carrying costs are calculated for 35-, 40- and 45-foot poles. The charge is calculated by multiplying a usage factor of 0.0759 by the annual carrying costs of a bare pole. The 0.0759 usage factor was the prescribed percentage for a three-user pole set forth in the Commission's Order in Administrative Case No. 251 dated September 17, 1982, and assumes that a cable television attachment would utilize one foot of the usable space on the pole. In calculating bare pole costs, 15% of the pole costs have been removed from plant in service costs for

35-, 40- and 45-foot poles to reflect the elimination of appurtenances.

Q. How are the carrying charges calculated?

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

Q. Are the charges based on net depreciated plant?

A. Yes. Net depreciated plant (or rate base), along with straight line depreciation, is used in the carrying charge calculation. This approach is consistent with the way that all other revenue requirements are determined in these proceedings. Therefore, the charges shown in Exhibit WSS-16 are reflective of current revenue requirements associated with the cost of providing attachment service.

B. NON-RESIDENTIAL LATE PAYMENT CHARGES

Q. Are the Companies proposing to modify policies related to their late payment charges?

A. Yes. The Companies are proposing to waive a non-residential customer's late payment charge if the customer requests a waiver and has not incurred a late payment charge in the previous 11 billing cycles. The Companies implemented a similar policy for residential customers in their last rate cases.

Q. Are the Companies making an adjustment to miscellaneous revenues to reflect

the waiver?

A. No. The Companies will absorb the impact of the waiver until any future rate cases, at which time the impact of the change would be reflected in test year miscellaneous revenues in such future rate cases.

C. EXCESS FACILITIES CHARGES

Q. Please describe the Companies' Excess Facilities Rider.

A. The Excess Facilities Rider applies to customer requests for service arrangements requiring equipment and facilities in excess of those the Companies would normally install. Examples of excess facilities include requests for non-standard facilities such as emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters. Under the rider, customers have the option of either (i) requesting that KU or LG&E incur the full cost of the equipment (including up-front equipment cost), in which event the monthly excess facilities charge would cover the expected carrying charges on the equipment, the estimated maintenance cost on the equipment, and the estimated cost of replacing the equipment if it fails prior to the service life of the facilities or (ii) making an up-front payment to cover the cost of the facilities, in which event the monthly excess facilities charge would only cover the estimated maintenance cost on the equipment and the estimated cost of replacing the facilities if they fail prior to the expected service life of the equipment. Because estimated failure costs would be included in the charge for either scenario, KU or LG&E would replace the equipment if it fails prior to the end of the specified service life under either option.

Q. What are the proposed excess facilities charges?

A. Under the first option, in which the Companies would make the up-front investment, the proposed monthly charges as a percentage of the original cost of the facilities are 1.17 percent for KU, 1.23 percent for LG&E's electric operations, and 1.15 percent for LG&E's gas operations. These are slight changes from the current charges of 1.16 percent for KU, 1.22 percent for LG&E's electric operations, and 1.15 percent for LG&E's gas operations.

Under the second option, in which the customer makes the initial up-front investment, the proposed monthly charges as a percentage of the original cost of the facilities are 0.47 percent for KU, 0.52 percent for LG&E's electric operations, and 0.45 percent for LG&E's gas operations. These are unchanged from the current charges.

Q. How are the excess facilities charges calculated?

A. For the first option, in which LG&E makes the up-front investment, the charge includes (i) the levelized carrying charges associated with both the original cost of the facilities and the present value of the expected replacement cost of the facilities, plus (ii) operation and maintenance expenses as a percentage of the original cost of the plant. The levelized carrying charge rate is calculated using an 8.43 percent cost of capital for KU and an 8.38 percent cost of capital for LG&E for the estimated 30-year recovery period for long-lived distribution property. The present value of the expected replacement costs is determined using an actuarial approach based on Iowa-type survivor curves, which are the survival frequency distributions developed by Iowa State University that are used in depreciation studies for electric and gas utilities throughout the U.S. Specifically, the present value replacement cost is determined by calculating the replacement cost for each year based on the failure percentage given by a specified survivor curve and adjusted to reflect a three percent inflation factor. A 30-year R-2 Iowa curve is used to determine the annual replacement percentages. This curve is typical of an Iowa curve that might be used for transformers and other distribution facilities.

For the second option, in which the customer makes the initial up-front investment, the charge includes (i) the levelized carrying charges associated with the present value of the expected replacement cost of the facilities, plus (ii) operation and maintenance expenses as a percentage of the original cost of plant. Therefore, under this option, the charge would not include the carrying charges associated with the initial cost of the facilities but would include carrying charges on the present value of the replacement cost.

For both options, the operation and maintenance component is determined by dividing (i) actual operation and maintenance expenses less purchased power expenses during the test year by (ii) electric plant in service as of the end of the test year. Cost support for the proposed excess facilities charges is included in Exhibit WSS-17. The impact on other operating revenues is shown in Exhibit WSS-18.

D. OTHER MISCELLANEOUS CHARGES

Q. Are KU and LG&E proposing changes to any other miscellaneous charges?

A. Yes. LG&E is proposing to increase its electric and gas disconnect/reconnect service charges from $28.00 to $32.00, and KU is proposing to increase its disconnect/reconnect service charge from $28.00 to $37.00. KU is proposing to increase its returned check charge from $3.00 to $3.50, and LG&E proposing to increase its returned check charge from $3.00 to $3.70. For electric meters, KU and LG&E are proposing to increase the meter-test charge from $75.00 to $79.00. For gas meters, LG&E is proposing to increase its meter-test charge from $90.00 to $101.00. For gas service, LG&E is proposing to increase its inspection charge and its additional trip charge from $150.00 to $155.00.

For electric meters, KU and LG&E are proposing to decrease the meter pulse relay charge from $24.00 to $21.00. For gas meters, LG&E is proposing to increase its meter pulse charge for transportation customers served under FT and TS2 from $7.17 to $8.00 and from $24.34 to $28.00 for all other types of customers.

KU is proposing to modify the unauthorized reconnect charges as follows: (i) from $70.00 to $45.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter; (ii) from $90.00 to $66.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter; (iii) from $110.00 to $87.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter; (iv) from $174.00 to $149.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Infrastructure (AMI) meter; and (v) from $177.00 to $154.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

For electric service, LG&E is proposing to modify the unauthorized reconnect charges as follows: (i) from $70.00 to $49.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter; (ii) from $90.00 to $70.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter; (iii) from $110.00 to $91.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter; (iv) from $174.00 to $153.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Infrastructure (AMI) meter; and (v) from $177.00 to $159.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

For gas service, LG&E is proposing to modify the unauthorized reconnect charges as follows: (i) from $70.00 to $49.00 for unauthorized reconnects that do not require the replacement of a meter, and (ii) from $132.00 to $114.00 for unauthorized reconnects that require the replacement of a meter. The cost support for these charges is shown in Exhibit WSS-19, and the impact on other operating revenues is shown in Exhibit WSS-20.

Q. Are KU and LG&E proposing AMI Opt-Out Charges?

A. Yes. Mr. Conroy’s testimony explains why the Companies are proposing the charges and when they will apply.

Q. What are the Companies’ proposed AMI Opt-Out Charges?

A. The Companies are also proposing an up-front opt-out setup charge per meter ($39.00

for KU, $35.00 for LG&E-E, and $33.00 for LG&E-G) and a recurring monthly opt-out charge per meter ($15.00 for KU, $12.00 for LG&E-E, and $5.00 for LG&E-G) applicable to customers who choose to opt out of the proposed Advanced Metering Infrastructure (AMI) deployment.

Q. How do the Companies' proposed AMI Opt-Out Charges compare to similar charges for other utilities?

A. The following table (TABLE 6) shows the AMI opt-out charges for other utilities in the United States:

TABLE 6

Utility	AMI Opt-out Set-up Fee	Monthly AMI Opt-Out Fee
Duke Energy Progress (NC)	$170.00	$14.75
Duke Energy Progress (SC)	$170.00	$14.75
Duke (KY)	$100.00	$25.00
Duke Energy (OH)	$100.00	$30.00
Duke Energy (FL)	$96.34	$15.60
AEP Michigan	$80.30	$9.75
Portland General	$80.00	$17.00
Duke Energy (IN)	$75.00	$17.50
AEP Ohio	$43.00	$24.00
Central Maine Power	$40.00	$16.05

The Companies' proposed AMI opt-out charges are toward the bottom end of the charges assessed by other utilities.

Q. What costs are recovered through the proposed charges?

A. The one-time charge includes: (i) the cost of creating work orders for meter change-out and the routing of meter readers, (ii) travel time, transportation cost and direct costs to remove the AMI electric meters or gas modules and replace them with non-AMI meters or gas modules; and (iii) customer service administrative costs.

The recurring charge includes the following costs: (i) costs for meter readers, dispatchers, supervisors, and transportation costs; (ii) costs, including transportation costs, for manual off-cycle meter reads by meter readers and fields services employees necessary to perform meter readings services for non-AMI meters; (iii) on-going maintenance costs related to the incremental mesh network; (iv) the cost of additional relays, access point, and supporting infrastructure related to the AMI mesh network; (v) system updates, staff training, and testing of billing system to handle opt out requests; and (vi) updating the billing system to handle AMI opt out billing, including system testing and training of staff.

Because the vast majority of LG&E's gas customers also receive electric service from LG&E, the travel time and cost for manually reading the non-AMI meters were reduced in calculating the cost of the AMI opt-out for gas customers, thus resulting in a lower opt-out charge for LG&E's gas customers than for its electric customers. These considerations do not impact the one-time charge for gas AMI opt-out. This ensures that combination gas and electric customers served by LG&E will not be overcharged. For LG&E's gas customers not taking electric service from either LG&E or KU, non-AMI telemetry (one-way AMR telemetry) would be utilized that will allow LG&E in most cases to avoid manually reading the meters. The cost support for the opt-out charges is shown in Exhibit WSS-19. None of the costs or revenues from customer opt-outs are included in test-year operating revenues and expenses in these proceedings. Upon implementation of the AMI opt-out charge, it is anticipated that the revenue collected from the charges will offset the cost of any customers that choose to opt out of AMI.

V. ADVANCED METERING INFRASTRUCTURE (AMI)

A. PERSONAL EXPERIENCE WITH AMI

Q. Have you worked with utilities that have implemented Advanced Metering Infrastructure (AMI) programs?

A. Yes. Most of my electric cooperative and investor-owned utility clients have implemented AMI.

Q. Has AMI been useful in performing cost of service studies and in designing rates?

A. Yes. The demand data collected from AMI have improved the accuracy of the cost of service studies. Without AMI, utilities would rely on sampled load data or data for other utilities to develop demand allocators used in cost of service studies. With AMI, utilities have demand data for almost every customer on the system; therefore, demand allocation factors are essentially exact, with very little estimation required to develop the three categories of demand allocation factors typically used in cost of service studies – namely, coincident peak allocators, maximum class demand allocators, and maximum individual customer demand allocators. The availability of this data is also used to develop accurate loss studies for utilities, which are used in cost of service studies.

AMI has also allowed utilities to develop innovative rate designs for a broader group of customers. Specifically, AMI has allowed utilities to develop a multitude of time-of-day rate options for all of their customers, without installing special purpose metering whenever a customer requests a special rate. With the utilities I have worked with, those with AMI can quickly roll out a new time-differentiated or real-time rate to a broad group of customers without installing specialized metering equipment specifically programed for a certain rate structure. With AMI, the meters can be interrogated remotely for application of a specific rate design.

B. FUTURE RATE OFFERINGS

Q. Would the Companies be well positioned to offer more time-of-day offerings once AMI is implemented?

A. Yes. KU and LG&E currently offer time-of-day offerings to residential customers, but the rate schedules are limited to 500 participants for each company. In these proceedings, the Companies are proposing to offer two optional General Time of Day Services (Rate GTOD-Energy and GTOD-Demand) that would be available to any General Service (Rate GS) customer enrolled in the Advanced Metering Systems Customer Service Offering set forth in the Companies' Demand-Side Management Cost Recovery Mechanism. The Companies do not currently offer four-part time-of-day rates for Power Service Rate PS customers.

VII. ELECTRIC COST OF SERVICE STUDIES

Q. Did The Prime Group prepare cost of service studies for KU and for LG&E's electric operations based on forecasted financial and operating results for the 12 months beginning July 1, 2021?

A. Yes. The Prime Group prepared fully allocated embedded cost of service studies based on a forecasted test year beginning July 1, 2021 for KU and for LG&E's electric operations. The cost of service study for LG&E's gas operations will be discussed later in my testimony. The cost of service studies correspond to the pro-forma financial exhibits that the Companies are providing to meet the requirements of Section 16(8). The Companies' objectives in performing the electric cost of service studies were to determine the rate of return on rate base the Companies are earning from each customer class, allocate revenue requirements as fairly as possible among all of the classes of customers the Companies serve, and provide the data necessary to develop rate components that more accurately reflect cost causation.

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

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

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

A. Regardless of whether a historical test year or a forecasted test year is used to develop a cost of service study, the methodology for developing a cost of service study is basically the same. The three traditional steps of an embedded cost of service study –

functional assignment, classification, and allocation – were utilized to classify costs. The cost of service studies for KU and LG&E were therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then finally (3) costs were allocated to the rate classes. These steps are depicted in the following diagram (Figure 1).

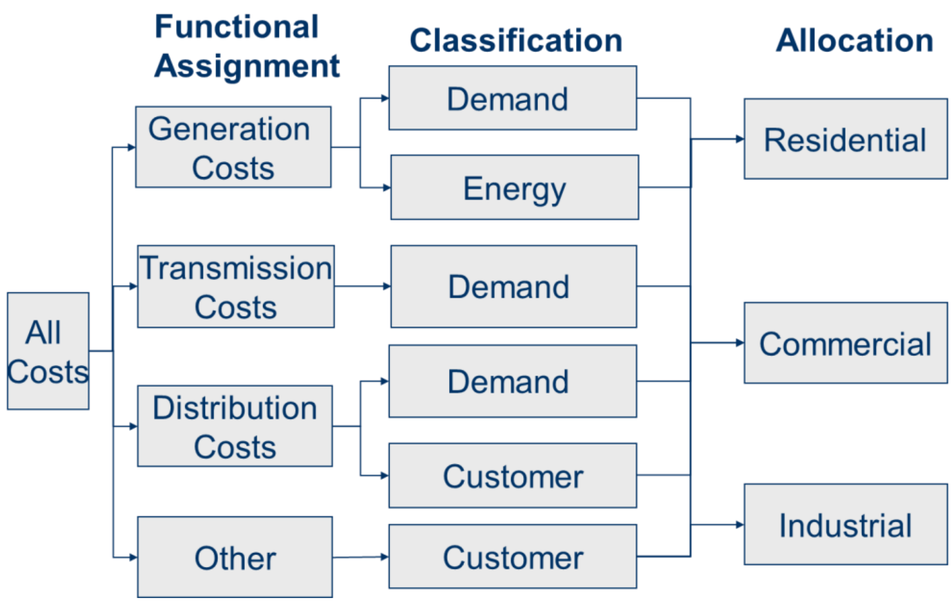

Figure 1

The following functional groups were identified in the cost of service studies: (1) Production, (2) Transmission, (3) Distribution Substation, (4) Distribution Primary Lines, (5) Distribution Secondary Lines, (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer

Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense. Because KU operates in multiple jurisdictions, it was necessary to identify costs for the Kentucky jurisdiction prior to developing a cost of service study. Therefore, the spreadsheet model used to perform the cost of service study also includes a jurisdictional separation analysis.

Q. Did you supervise the preparation of KU's jurisdictional separation study for the forecasted test period?

A. Yes. Because KU operates in three jurisdictions (Kentucky State Jurisdiction, Virginia State Jurisdiction, and FERC Jurisdiction), *joint costs* incurred to provide service *jointly* to all three jurisdictions, such as production fixed costs, must be *allocated* to the jurisdictions based on relative cost responsibility by jurisdiction, and any identifiable *direct costs* incurred in providing service to a particular jurisdiction must be *directly assigned* to that jurisdiction. Because production plant, for example, is *jointly used* by all three jurisdictions to meet each jurisdiction's demand requirements, these *joint costs* related to production plant must be allocated to the jurisdictions based on the demand responsibility of each jurisdiction relative to the total. On the other hand, distribution plant costs are recorded on KU's accounting records *by jurisdiction* and can be *directly assigned* to each jurisdiction. The jurisdictional separation study generated the Kentucky jurisdiction allocation factors shown on Schedule B-7.

Q. How were production fixed costs allocated in the Companies' cost of service studies?

A. KU and LG&E's production fixed costs were allocated using the Loss of Load Probability (LOLP) methodology, which was filed in the Companies' 2016 and 2018 rate case proceedings. Several intervenors supported the LOLP methodology in the 2016 proceedings.

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

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

$$\overline{PROD\ ALLOCATOR} = \sum_{i=1}^{8784} LOLP_i * \overline{LOAD}_i$$

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

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

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

i is the hour of the year.

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

Q. Is the LOLP approach a time-differentiated methodology?

A. Yes, and at a fine level of granularity. The LOLP methodology is identified in NARUC's *Electric Utility Cost Allocation Manual* as a standard methodology for performing time-differentiated cost of service studies. With the LOLP methodology, costs are differentiated for each hour of the test year. The approach can be adapted to calculate costs for any set of time periods during the test year Exhibit WSS-21 is a summary of the production fixed cost allocators used in the study.

Q. Was the revenue allocation set forth in the Stipulation in the Companies' last rate cases based on the LOLP methodology?

A. Yes. In its Orders in those rate cases, the Commission directed the Companies to file an alternative production cost allocation methodology along with the LOLP cost of service study.

Q. Are the Companies filing alternative cost of service studies in compliance with the Commission's Orders?

A. Yes. In addition to the LOLP cost of service study, the Companies are also filing the only two alternative methodologies submitted by intervenors in Case Nos. 2018-00294 and 2018-00295: a 12 CP cost of service study, which was proposed by the Kentucky Industrial Utility Customers, Inc.'s ("KIUC's") witness,[28] and a 6 CP cost of service study, which was proposed by Federal Executive Agencies' ("FEA's") witness.[29]

Q. Please describe the 12 CP and 6 CP methodologies.

A. The 12 CP methodology allocates production fixed costs on the sum of the monthly coincident peak demands for each rate class. The 6 CP methodology allocates production fixed costs on the sum of the monthly coincident peak demands for each

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[28] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Testimony of Stephen J. Baron (Ky. P.S.C. Jan. 16, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Testimony of Stephen J. Baron (Ky. P.S.C. Jan. 16, 2019).

[29] Case No. 2018-00294, Testimony of James T. Selecky (Ky. P.S.C. Jan. 16, 2019); Case No. 2018-00295, Testimony of James T. Selecky (Ky. P.S.C. Jan. 16, 2019).

rate class during the four summer months of June through September and the two winter months of January and February.

Q. Do you have a preference between the two alternative methodologies?

A. Yes. The 6 CP methodology more accurately reflects the Companies' generation planning than the 12 CP methodology. The Companies' system is summer peaking but the Companies also have a large winter peak. Therefore, the Companies give considerable attention to the winter peak demands, particularly in selecting the type of generation resources needed to meet both the summer and peak demands. But very little consideration is given to the system peak demands during the spring and fall months. Because the 12 CP methodology includes monthly demands for shoulder months such as March, April, May, October, and November, the methodology gives too much weight to demands for months that play little or no role in planning. By including demands for four summer months and two winter months, the 6 CP gives an appropriate weighting to the allocation of production costs for a summer peaking utility with a winter peak that is nearly as high as the summer peak. For these reasons, I favor the 6 CP over the 12 CP methodology. But a problem with both the 12 CP and 6 CP methodologies is that both methods rely on demands for a limited number of hours during the year. The LOLP methodology is more robust in that it weights all hours by the LOLPs for each hour of the year, which is a key metric in the Companies' generation system planning activities.

Q. Have you prepared an exhibit that compares the class rates of return for the three methodologies?

A. Yes. Exhibit WSS-22 compares the class rates of return using the LOLP methodology, 12 CP methodology, and the 6 CP methodology. The spreadsheet workpapers for the alternative cost of service studies are being provided electronically.

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

A. Classification involves utilizing the appropriate cost driver for each functionally assigned cost, which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. For costs classified as *energy-related*, the appropriate cost driver is the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand-related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. The costs of production plant and transmission lines are examples of costs typically classified as demand-related costs. Costs classified as *customer-related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, a portion of the costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer

Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related because these costs do not vary with customers' capacity or energy usage.

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

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

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

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

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

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

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

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

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

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

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

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

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

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

A. Yes. The Commission found LG&E's cost of service studies (both electric and gas) submitted in Case No. 2000-080 and Case No. 90-158 to be reasonable, thus providing a means of measuring class rates of return that are suitable for use as a guide in developing appropriate revenue allocations and rate design. The cost of service studies in both proceedings utilized a zero-intercept methodology to calculate the splits between demand-related and customer-related distribution costs. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2018-00294 and 2018-00295, the Companies' last two rate cases.

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

A. Yes. For KU, the zero-intercept analyses for overhead conductor, underground conductor, and line transformers are included in Exhibits WSS-23, WSS-24 and WSS-25, respectively. For LG&E, the zero-intercept analyses for overhead conductor, underground conductor, and line transformers are included in Exhibits WSS-26, WSS-27 and WSS-28, respectively. For overhead conductor, the LG&E results were utilized because the weighted regression analysis for KU did not yield statistically valid results.

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

A. Yes. Exhibit WSS-29 shows the results of the first two steps of the electric cost of service study, namely functional assignment and classification, for KU. Exhibit WSS-

30 shows the same two steps for LG&E. In the cost of service model used in this study, the calculations for functionally assigning and classifying Companies' accounting costs are made using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*[30]) by the dollar amount in the various accounts to simultaneously functionally assign and classify KU and LG&E's accounting costs. These calculations are made in the portion of the cost of service model included in Exhibits WSS-29 (KU) and WSS-30 (LG&E). In these exhibits, the Companies' accounting costs are functionally assigned and classified using explicitly determined functional vectors (i.e., "external vectors") and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 29 and 30 of Exhibits WSS-29 for KU and WSS-30 for LG&E. Internally generated functional vectors are utilized throughout the study to functionally assign and classify costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 29 and 30 of Exhibits WSS-29 for KU and WSS-30 for LG&E. The functional vector used to allocate a specific cost is identified in the column of the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

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

Q. Please describe how the functionally assigned and classified costs were allocated to the various classes of customers.

A. Exhibits WSS-31 (KU) and WSS-32 (LG&E) show the allocation of the functionally assigned and classified costs to the various classes of customers that KU and LG&E serve. For a forecasted test year, the average number of customers is used for allocating customer-related costs rather than the year-end number of customers that is used for a historical test year. The following allocation factors were used in the electric cost of service study to allocate the functionally assigned and classified costs:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the loss adjusted kWh sales to each class of customers during the test year.
- **LOLP** – The cost components of production fixed costs were allocated on the basis of the total sum of each class's contribution to the forecasted loss of load probability during every hour of the test year.
- **NCPT –** The demand cost component is allocated based on the maximum class demands for transmission, primary and secondary voltage customers. This allocation vector is used to allocate transmission costs.
- **NCPP** – The demand cost component is allocated on

the basis of the maximum class demands for primary and secondary voltage customers. This allocation vector is used to allocate distribution substations and primary distribution demand-related costs.

- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **Cust04** – Customer-related O&M costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **PCust04** – Customer-related plant and rate base associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05 and Cust06** – Meter reading, billing costs and

customer service O&M expenses were allocated on the basis of a customer weighting factor calculated using the 12 month average number of customers for the test year based on discussions with the Companies' meter reading, billing and customer service departments.

- **PCust05 and PCust06** – Meter reading, billing costs and customer service plant expenses were allocated on the basis of a customer weighting factor calculated using the 13 month average number of customers for the test year based on discussions with the Companies' meter reading, billing and customer service departments.
- **Cust07** – Customer-related O&M costs for secondary-voltage distribution facilities are allocated on the basis of the 12 month average number of customers using line transformers and secondary voltage conductor.
- **PCust07** – Customer-related plant costs for secondary-voltage distribution facilities are allocated on the basis of the 13 month average number of customers using line transformers and secondary voltage conductor.
- **Cust08** – Customer-related O&M costs for primary-

voltage distribution facilities are allocated on the basis of the 12 month average number of customers using primary voltage conductor.

- **PCust08** – Customer-related plant costs for primary-voltage distribution facilities are allocated on the basis of the 13 month average number of customers using primary voltage conductor.
- **Cust09** – Customer-related O&M costs for transformers are allocated on the basis of the 12 month average number of customers using distribution transformers.
- **PCust09** – Customer-related plant costs for transformers are allocated on the basis of the 13 month average number of customers using distribution transformers.
- **GPLOLPDA, NPLOLPDA, RBLOLPDA, POMLOLPDA, PDEPLOLPDA, and PPTLOLPDA** **–** These allocators are used to specifically assign production-related demand costs associated with the Solar Share and Business Solar programs directly to those respective rate classes. These allocators directly

assign Gross Plant, Net Plant, Net Rate Base, O&M, Depreciation, and Property Taxes associated with those programs directly to customers participating in those programs.

- **MGPA, MNPA, MRBA, MOMA, MDA, and MPTA** – These allocators are used to specifically assign customer-related costs associated with the Electric Vehicle Charging programs directly to those respective rate classes. These allocators directly assign Gross Plant, Net Plant, Net Rate Base, O&M, Depreciation, and Property Taxes associated with those programs directly to customers participating in those programs.

Q. Once costs are functionally assigned and classified, what calculations are used to allocate these costs to the various customer classes the Companies serve?

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

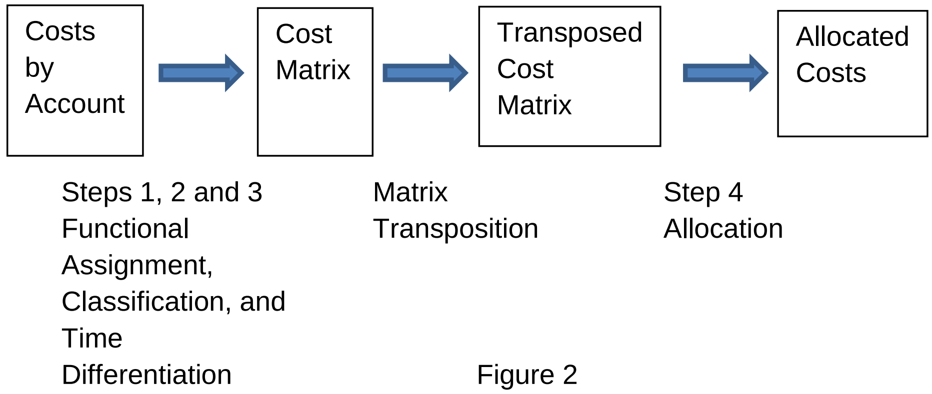

Figure 2

The results of the class allocation step of the cost of service study are included in Exhibits WSS-31 (KU) and WSS-32 (LG&E). The costs shown in the column labeled "Total System" in Exhibits WSS-29 and WSS-30 were carried forward from the functionally assigned and classified costs shown in Exhibits WSS-31 and WSS-32, respectively. The column labeled "Ref" in Exhibits WSS-31 and WSS-32 provides a reference to the results included in Exhibits WSS-29 and WSS-30, respectively.

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

A. The Current Rate of Return on Rate Base was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the rate base, income and expenses discussed in the testimony of Mr. Garrett. The Proposed Rate of Return on Rate Base was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. The determination of the actual adjusted and proposed rates of return are shown on pages 25 through 28 and pages 27 through

30, respectively, of Exhibits WSS-31 and WSS-32, for KU and LG&E, respectively. The rates of return by customer class for the LOLP cost of service study along with the 6-CP and 12-CP methodologies are shown in Exhibit WSS-22

VIII. GAS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for LG&E's gas operations based on financial and operating results for the 12 months beginning July 1, 2021?

A. Yes. I supervised the preparation of a fully allocated, embedded cost of service study for gas operations for the forecasted test year beginning July 1, 2021, based on LG&E's forecasted accounting costs. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Garrett. As with the electric cost of service studies, the objective in performing the gas cost of service study is to determine the rate of return on rate base that LG&E is earning from each customer class, allocate LG&E's natural gas revenue requirement as fairly as possible to the various classes of customers that LG&E serves, and provide the data necessary to develop rate components that more accurately reflect cost causation.

Q. Generally, were the procedures used in performing the gas cost of service study the same as those that you described above for the electric cost of service studies?

A. Yes. The gas cost of service study was prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups, (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then finally (3) costs were allocated to the various natural gas rate classes that

LG&E serves. These steps are depicted in the following diagram (Figure 3). This is a standard approach utilized in the preparation of embedded cost of service studies for natural gas utilities.

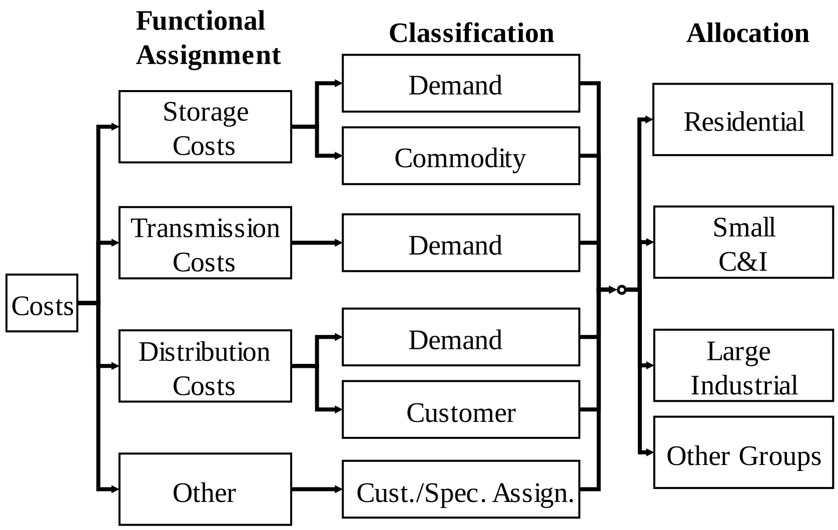

Figure 3

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

A. The following functional groups were identified in the cost of service study: (1) Procurement, (2) Storage, (3) Storage-Related Transmission, (4) Non-Storage-Related Transmission, (5) Distribution Commodity, (6) Distribution Structures and Equipment, (7) Distribution Mains – Low- and Medium-Pressure, (8) Distribution Mains – High-Pressure, (9) Services, (10) Meters, (11) Customer Accounts, and (12) Customer Service Expense.

Q. Please describe the functional assignment of transmission costs.

A. There are two functional groups for transmission costs: Storage-Related Transmission and Non-Storage-Related Transmission. Storage-Related Transmission costs represent the transmission facilities that are used to deliver natural gas from LG&E's storage fields to the distribution system. The Non-Storage-Related Transmission functional group represents costs of transmission facilities used to deliver gas from interstate pipelines both to the distribution system and directly to customers. It is important to distinguish between the two types of costs because the Non-Storage-Related Transmission facilities are used to serve all customer classes, including both sales and transportation customers, by delivering gas to the distribution system and directly to individual customers, whereas the use of Storage-Related Transmission facilities is limited to delivering storage gas to sales customers and to serving daily imbalances created by transportation customers. Therefore, the use of Storage-Related Transmission facilities to serve customers under Rate FT and any other firm transportation-only service would be limited to their use of daily imbalance service facilitated through storage. Exhibit WSS-33 shows the derivation of the functional assignment for transmission plant.

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

A. Classification involves identifying the appropriate cost driver for each account, which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *commodity-related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand-related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer-related* include non-volumetric costs incurred to serve customers that are invariant to either the quantity of gas delivered to the customers or the peak demand requirements of the customers. All transmission plant costs were classified as demand-related. The transmission plant used to deliver natural gas from and to storage is allocated on the same basis as storage. The transmission plant used to deliver gas from the pipelines into LG&E's distribution system was allocated on design-day demands. Distribution Structures and Equipment costs were classified as demand-related. Costs related to Distribution Mains were functionally assigned as either low- and medium-pressure mains or high-pressure mains and then classified as demand-related and customer-related using the zero-intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were classified as customer-related.

Q. Explain the zero-intercept methodology that you used to classify the costs of mains between demand-related and customer-related costs.

A. A portion of the cost of mains was classified as demand-related and a portion was classified as customer-related using the zero-intercept methodology, which was described above in connection with the electric cost of service study. The zero-intercept analysis is included in Exhibit WSS-34.

Q. How were distribution mains functionally separated between high-, low- and

medium-pressure categories?

A. The feet of high-pressure mains by size of pipe were identified from LG&E's maps and records. The feet of low- and medium-pressure pipe were determined residually by subtracting the specifically identified high-pressure mains from the total feet for each pipe size. The zero-intercept unit cost of $10.91 was then applied to the high-pressure mains and to the low- and medium-pressure mains to determine the customer-related portion of the mains.[31] By identifying high-pressure mains from LG&E's maps and records, it was determined that LG&E's high-pressure distribution mains represent 9.37% of the total installed cost, with 4.44% corresponding to customer-related costs and 4.92% corresponding to demand-related costs. The low- and medium-pressure pipe make up the remaining 90.63% of installed cost, with 62.27% classified as customer-related and 28.36% classified as demand-related. The breakdown is shown on Exhibit WSS-34. The allocation of the cost to the customer classes is shown on Exhibit WSS-35.

Q. Was a similar separation made in the electric cost of service studies?

A. Yes. The electric cost of service studies separate distribution conductor between primary voltage conductor and secondary voltage conductor. The functional separation in the gas cost of service study between high-pressure and low- and medium-pressure pipe is analogous to the primary and secondary splits determined in

[31] The cost of service study used the zero intercept results from the detailed analysis that was performed based on plant records as of June 30, 2020.

the electric cost of service studies. Differences in the pressure in a pipe are often used as an analogy to differences in voltages.

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

A. Yes. Exhibit WSS-36 shows the results of the first two steps of the natural gas cost of service study: functional assignment and classification.

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

A. The results of allocating LG&E's functionally assigned and classified costs to the various classes of customers that LG&E serves are provided in Exhibit WSS-37. The following allocation factors were used in the gas cost of service study:

- **DEM01** is used to allocate procurement demand-related costs; these costs are the procurement-related expenses that are not recovered through LG&E's Gas Supply Clause.

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on extreme winter season requirements and design-day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the design winter season and (b) the volumes needed in storage to meet the design-day demands. Rate FT is assigned an allocation based on its utilization of balancing service in accordance with the provision set forth in the rate schedule to allow imbalances that do not exceed ± 5% of delivered volumes when an Operational Flow Order ("OFO") has not been issued. The calculation of this allocation factor is shown in Exhibit WSS-38.

- **DEM03** is used to allocate Transmission demand-related costs for the portion of the transmission system that is used to move gas to and from storage. Because this portion of LG&E's transmission lines is used to either fill the storage fields or remove gas from storage, transmission demand-related costs are allocated on the same basis as storage demand-related costs.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents forecasted maximum class demands determined at

LG&E's -14° F design-day mean temperature.

- **DEM05** is used to allocate the demand-related portion of the cost of high-pressure distribution mains and the cost of transmission lines used to move gas from the pipelines to LG&E's distribution system. It represents maximum class demands determined at the design-day mean temperature of customers served at high-pressure or below. The high-pressure system consists of pipe pressured above 60 psi. All gas delivered into the low- and medium-pressure system must first pass through the high-pressure system. Consequently, all customers utilize the high-pressure system.

- **DEM05a** is used to allocate the demand-related portion of the cost of low- and medium-pressure distribution mains and represents maximum class demands determined at the design-day mean temperature of customers served at medium pressure or low pressure. The low- and medium- pressure system consists of pipe pressured at 60 psi and below. The demands of customers served at high pressure are not included in the determination of this allocation factor. The low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

- **COM01** is used to allocate commodity-related procurement expenses and represents annual throughput volumes (including both sales and transportation). Procurement expenses correspond to expenses incurred by LG&E's gas supply department (including labor), which are not recovered through the Gas Supply Clause. This department not only purchases gas for sales customers but also administers LG&E's transportation service schedules.

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

- **COM03** is used to allocate Transmission commodity-related costs and represents forecasted customer class deliveries during the winter withdrawal season (defined as the months of November through March.)

- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation.)

- **CUSTPT01** is used to allocate the customer-related portion of LG&E's high-pressure distribution mains and represents the 13-month average number of customers served at high pressure and below.

- **CUSTPT01a** is used to allocate the customer-related portion of LG&E's low- and medium-pressure distribution mains and represents the 13-month average number of customers at low and medium pressure. The customers served at high pressure are not included in the determination of this allocation factor because the low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

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

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

- **CUSTPT04** is used to allocate the plant and rate base components of customer accounts expense and represents 13-month average customers.

- **CUSTPT05** is used to allocate the plant and rate base components of customer service. It is based on 13-month average customers adjusted for weighting factors for each class.

- **CUSTOM01** is used to allocate the customer-related portion of O&M expenses for high-pressure distribution mains and represents the 12-month average number of customers served at high pressure and below.

- **CUSTOM01a** is used to allocate the customer-related portion of O&M expenses for low- and medium-pressure distribution mains and represents the average number of customers at low and medium pressure. The customers served at high pressure are not included in the determination of this allocation factor because the low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

- **CUSTOM04** is used to allocate customer accounts expenses (Accounts 901 through 905) and represents a composite allocation factor.[32]

[32] This allocation factor is determined as follows: First, customer accounts supervision (Account 901), meter reading (Account 902), customer records and collections (Account 903), and miscellaneous customer account expenses (Account 905) were allocated to each customer class using a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments. A cost weighting factor of 1.0 was utilized for Residential Gas Service, a cost weighting factor of 1.1 was utilized for Commercial Gas Service, a cost weighting factor of 10 was utilized for Rates IGS and AAGS, and a customer weighting factor of 20 was utilized for Rate FT and special contracts. Using a cost weighting factor of 20 for Rate FT and special contracts, for example, means that the cost of performing the meter reading, billing and customer service functions for customers served under Rate FT is 20 times more than the cost of performing these same services for customers served under Rate RGS.

- **CUSTOM05** is used to allocate customer service expenses using the same customer-weighting factor used to allocate Accounts 901, 902, 903, and 905 as in the calculation of CUST04.

Q. Summarize the results of the gas cost of service study.

A. The rates of return shown on net cost rate base for natural gas service for each customer class before and after reflecting the rate adjustments proposed by LG&E are shown on pages 12 and 13 of Exhibit WSS-37. The current rate of return on net cost rate base was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the forecasted amounts discussed in the testimony of Mr. Garrett. The proposed rate of return on net cost rate base was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. Rate DGGS is not broken out in the cost of service study but is included in Rate IGS. Rate LGDS is not shown in the table because there are currently no customers served under the rate schedule. Currently, there is one commercial customer served under Rate SGSS. However, Rate SGSS is not broken out in the cost of service study but is included in Rate CGS.

IX. LEAD-LAG STUDIES

Q. Did KU and LG&E perform a lead lag study in Case Nos. 2018-00294 and 2018-00295?

A. Yes. I supervised the preparation of the lead-lag studies for KU and for LG&E's electric and gas operations. Mr. Garrett provided the balance sheet analyses used for the study of cash working capital based on amounts from the Companies' forecast. The lead-lag studies used historical payment activity to calculate revenue lag days and expense lead days. *Revenue lag days* represent the difference between the date when services are rendered by the Companies and the date when revenues for those services are collected from customers. *Expense lead days* represent the date when expenses are incurred to provide service and the date when those expenses are paid. The net lead-lag days are multiplied by the respective average daily expenses and pass-through items (*viz*., sales taxes, school taxes, and franchise fees) to determine cash working capital.

Q. In Kentucky, are utilities required to perform a lead-lag study?

A. No. In the Stipulation Agreement in Case Nos. 2016-00370 and 2016-00371, the Companies agreed to submit lead-lag studies in their next general rate cases. The Companies then filed lead-lag studies in Case Nos. 2018-00294 and 2018-00295. In the current rate cases, KU and LG&E are updating the revenue lag analysis and balance sheet analysis that were filed in Case Nos. 2018-00294 and 2018-00295. By updating the revenue lag analysis and balance sheet analysis, the Companies are following the practice prescribed by the Virginia State Corporation Commission (VA

SCC) for rate case filings in Virginia, which prescribes that if a lead-lag study is less than five years old then only revenue lags and the balance sheet analysis are updated.[33]

Q. Based on your experience, is this practice reasonable?

A. Yes. Unless there is a dramatic change in a utility's financial condition, it has been my experience that expense leads do not change significantly within a five-year period. Performing a lead-lag study is a major undertaking. Therefore, it is reasonable to update revenue lags and the balance sheet analysis if the lead-lag study has been performed within the last five years.

Q. What period was used to perform the revenue lag analysis?

A. The revenue lag analysis was performed using revenue and expense data for the calendar year 2019.

Q. How were revenue lag days determined?

A. The revenue lag measures the number of days from the date service was rendered by the Companies until the date payment was received from customers and the funds deposited and available to the Companies. In the calculation, the revenue lag consists of four time spans: (1) meter reading lag, which is the time period from the midpoint of the service period to the meter read date; (2) billing lag, which is the period from when the meter is read to the date when the bill is invoiced; (3) collection lag, which is the period from when the bill is invoiced to when the customer payment is received;

[33] Virginia Administrative Code 20 VAC5-201-10 – Rules Governing Utility Rate Applications and Annual Information Filings with the VA SCC specifies that "Utilities required to use a lead/lag study should perform a complete lead/lag analysis every five years. Major items such as the revenue lag and balance sheet accounts should be reviewed every year."

and (4) bank lag, which is the period from when the customer payment is received to when the Companies have access to the funds. The collection lag was determined using the turnover approach, which calculates the collection lag days by dividing the average daily accounts receivable balance by the average daily revenues and pass-through items (*viz*., sales taxes, gross receipt taxes, and franchise fees). The turn-over method was used in KU-ODP's recent rate case filing in Virginia.

Q. Please summarize the components of the revenue lag for KU and LG&E's electric and gas operations?

A. The revenue lags by component are summarized below (TABLE 7):

TABLE 7

	Lag Days		
Lag Component	**KU**	**LG&E-Elec**	**LG&E-Gas**
Meter Reading Lag	15.21	15.21	15.21
Billing Lag	4.20	4.29	4.28
Collection Lag	25.09	23.77	23.77
Bank Lag	1.00	1.00	1.00
Total Revenue Lag	45.50	44.27	44.26

Q. Do you have an exhibit showing the lead-lag days for each category of revenue and expense?

A. Yes. The lead-lag days used to determine cash working capital are shown on Exhibit WSS-39. As mentioned earlier, the revenue lags have been updated based on an analysis of billings for 2019. The expense leads reflect values that were determined from the lead-lag study submitted in Case Nos. 2018-00294 and 2018-00295.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF BUNCOMBE)

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

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of November 2020.

Kyle Mello
NOTARY PUBLIC
BUNCOMBE COUNTY, NC
MY COMMISSION EXPIRES 7/29/2023

Notary Public (SEAL)

Notary Public ID No. 201821300096

My Commission Expires:

7/29/2023

Exhibit WSS-1

Qualifications

WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, municipal utilities, and public service commissions regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base. Mr. Seelye has performed or supervised the preparation of cost of service studies and rate design studies for over 150 electric, gas and water utilities.

Employment

Principal and Managing Partner
The Prime Group, LLC
(1996 to 2012) (2015-Present)
(Associate Member 2012-2015)

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service studies, rate design, fuel and procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic resource and marketing plans. Assist with resource planning and cost benefit analyses for generation investment projects. Performs economic analyses evaluating the costs and benefits of an electric generation projects; performs business practice audits for electric utilities, gas utilities, and independent transmission organizations, including audits of production cost modeling, fuel procurement practices and controls, and wholesale marketing procedures. Assists investor-owned utilities in the development of testimony regarding the prudence of power supply decisions and of investments in specific generation and distribution assets.

Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus

	of rate alternatives for use with customers; performance-based rate development. Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.
Instructor in Mathematics Walden School and Private Instruction (2012-2015)	Taught advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.
Manager of Rates and Other Positions Louisville Gas & Electric Co. (May 1979 to July 1996)	Held various positions in the rate department of LG&E. In December 1990, promoted to Manager of promoted to the position of Manager of Rates and Regulatory Analysis. In May 1994, give additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

<u>Education</u>
Bachelor of Science Degree in Mathematics, University of Louisville, 1979
66 Hours of Graduate Level Course Work in Electrical and Industrial Engineering and Physics.

<u>Associations</u>
Member of the Society for Industrial and Applied Mathematics

<u>Expert Witness Testimony</u>

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

Submitted expert report in Proceeding No. 14-CV-30031 before District Court, Prowers County, State of Colorado, on behalf of Arkansas River Power Authority in the *City of Lamar et al v. Arkansas River Power Authority regarding* power planning and operations.

Submitted expert report in Proceeding No. 19F-0315E before Public Utilities Commission of the State of Colorado, on behalf of San Luis Valley Rural Electric Cooperative in *Anne Pace, et al. v. San Luis Valley Rural Electric Cooperative* regarding demand charges for residential electric and distributed generation customers.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER11-2127-000 concerning transmission rates proposed by Terra-Gen Dixie Valley, LLC.

Submitted testimony in Docket No. ER11-2779 on behalf of Southern Illinois Power Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Submitted testimony in Docket No. ER11-2786 on behalf of Norris Electric Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and cross answering testimony in Cause No. 45125 on behalf of the City of New Haven regarding Fort Wayne's revenue requirement, cost of service study and the apportionment of the water rate increase.

Submitted direct and cross answering testimony in Cause No. 45142 on behalf of the City of Crown Point regarding Indiana-American Water Company's cost of service study, apportionment of the revenue increase, interruptible service rates and transportation service rates.

Submitted direct and cross answering testimony in Cause No. 45235 on behalf of the City of South Bend regarding Indiana-Michigan Power Company's cost of service study, apportionment of the revenue increase and rate design.

Submitted direct and cross answering testimony in Cause No. 45285 on behalf of the City of South Bend regarding Indiana-Michigan Power Company's demand side management (DSM) plan.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning revenue requirements, cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding revenue requirements, pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big

Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2010-00116 on behalf of Delta Natural Gas Company concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony in Case No. 2011-00036 on behalf of Big Rivers Electric Cooperative concerning cost of service, rate design, pro-forma TIER adjustments, temperature normalization, and support of MISO Attachment O.

Submitted testimony in Case No. 2016-00107 on behalf of Columbia Gas Company of Kentucky regarding a tariff application to continue its energy efficiency and conservation rider and programs.

Submitted testimony in Case No. 2016-00274 on behalf of Kentucky Utilities Company and Louisville Gas and Electric Company in support of community solar rates.

Submitted direct and rebuttal testimony in Case No. 2016-00370 on behalf of Kentucky Utilities Company and in Case No. 2016-00371 on behalf of Louisville

Gas and Electric Company regarding electric and gas class cost of service studies and proposed rates.

Submitted rebuttal testimony in Case No. 2018-00050 on behalf of South Kentucky Rural Electric Cooperative Corporation regarding the regulatory application of the filed rate doctrine and cost shifts to other electric cooperatives related to a proposed purchased power agreement.

Submitted testimony in Case No. 2018-00044 on behalf of Columbia Gas Company of Kentucky regarding an assessment of its energy efficiency and conservation rider and programs.

Submitted direct and rebuttal testimony in Case No. 2018-00294 on behalf of Kentucky Utilities Company and in Case No. 2018-00295 on behalf of Louisville Gas and Electric Company regarding electric and gas class cost of service studies, apportionment of the revenue increase, pilot school rates, demand ratchets, late payment charges, residential customer charges, excess facilities charges, LED lighting rates, and lead-lag studies.

Maryland Submitted direct testimony in PSC Case No. 9234 on behalf of Southern Maryland Electric Cooperative regarding a class cost of service study.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital, depreciation adjustments, and other rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 10-06001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate cases.

Submitted direct testimony in Case No. Docket No. 11-06006 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

New Mexico Submitted testimony in support of filing of Advice Notice No. 60 on behalf of Kit Carson Electric Cooperative, Inc.

Submitted direct testimony in Case No. 15-00375-UT on behalf of Kit Carson Electric Cooperative, Inc. regarding revenue requirements, the need for a rate increase, class cost of service study, apportionment of the revenue increase to the classes of service, and rate design.

Submitted testimony in Advice Notices in Case No. 15-00087-UT on behalf of Jemez Mountain Electric Cooperative in support of tribal right of way cost recovery surcharge mechanisms.

Submitted direct testimony in Case. No. 16-00065-UT on behalf of Kit Carson Electric Cooperative in support of an application for continuation of its fuel and purchased power cost adjustment clause.

Submitted direct testimony, rebuttal testimony, and testimony in support of an uncontested comprehensive stipulation in Case No. 19-00170-UT on behalf of the New Mexico Public Regulation Commission Utility Division Staff regarding revenue requirements, class cost of service, allocation of the revenue increase, and rate design in a Southwest Power Company rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2011-00013 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, and rate design.

Exhibit WSS-2

Cost Components for Residential Service Rate RS

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2022

Rate RS

		Production		Transmission	Distribution		Customer Service Expenses	
Description	**Amount**	**Demand-Related**	**Energy-Related**	**Demand-Related**	**Demand-Related**	**Customer-Related**	**Customer-Related**	**Total**
(1) Rate Base	$ 2,457,262,896	$ 1,219,918,258	$ 27,493,896	$ 377,164,232	$ 304,728,690	$ 521,584,458	$ 6,373,362	$ 2,457,262,896
(2) Rate Base Adjustments	$ -	-	-	-	-	-	-	$ -
(3) Rate Base as Adjusted	$ 2,457,262,896	$ 1,219,918,258	$ 27,493,896	$ 377,164,232	$ 304,728,690	$ 521,584,458	$ 6,373,362	$ 2,457,262,896
(4) Rate of Return	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	
(5) Return	$ 116,464,860	$ 57,819,458	$ 1,303,105	$ 17,876,142	$ 14,442,974	$ 24,721,108	$ 302,073	$ 116,464,860
(6) Interest Expenses	$ 51,506,086	$ 25,570,408	$ 576,293	$ 7,905,647	$ 6,387,344	$ 10,932,804	$ 133,590	$ 51,506,086
(7) Net Income	$ 64,958,773	$ 32,249,050	$ 726,813	$ 9,970,494	$ 8,055,630	$ 13,788,304	$ 168,483	$ 64,958,773
(8) Income Taxes	$ 20,618,122	$ 10,235,951	$ 230,693	$ 3,164,667	$ 2,556,883	$ 4,376,452	$ 53,477	$ 20,618,122
(9) Operation and Maintenance Expenses	$ 369,164,547	$ 54,624,948	$ 191,795,621	$ 25,536,905	$ 17,160,390	$ 37,627,884	$ 42,418,799	$ 369,164,547
(10) Depreciation Expenses	$ 164,107,492	$ 118,364,937	$ -	$ 15,509,606	$ 11,180,449	$ 19,052,501	$ -	$ 164,107,492
(11) Other Taxes	$ 23,280,695	$ 12,676,971	$ -	$ 3,123,044	$ 2,765,995	$ 4,714,686	$ -	$ 23,280,695
(12) Curtailable Service Credit	$ 7,647,274	$ 7,647,274						$ 7,647,274
(13) Expense Adjustments - Prod. Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(14) Expense Adjustments - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(15) Expense Adjustments - Trans. Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(16) Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(17) Expense Adjustments - Other	$ 352,093	$ 174,798	$ 3,940	$ 54,043	$ 43,664	$ 74,736	$ 913	$ 352,093
(18) Revenue Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(19) Expense Adjustments - Total	$ 352,093	$ 174,798	$ 3,940	$ 54,043	$ 43,664	$ 74,736	$ 913	$ 352,093
(20) Total Cost of Service	$ 701,635,083	$ 261,544,337	$ 193,333,359	$ 65,264,407	$ 48,150,353	$ 90,567,366	$ 42,775,263	$ 701,635,083
(21) Less: Misc Revenue - Prod Demand	$ (583,332)	$ (583,332)	$ -	$ -	$ -	$ -	$ -	$ (583,332)
(22) Less: Misc Revenue - Energy	$ (3,060,544)	$ -	$ (3,060,544)	$ -	$ -	$ -	$ -	$ (3,060,544)
(23) Less: Misc Revenue - Transmission	$ (11,743,851)	$ -	$ -	$ (11,743,851)	$ -	$ -	$ -	$ (11,743,851)
(24) Less: Misc Revenue - Other	$ (6,488,247)	$ (3,221,117)	$ (72,596)	$ (995,878)	$ (804,617)	$ (1,377,211)	$ (16,828)	$ (6,488,247)
(25) Less: Misc Revenue - Total	$ (21,875,974)	$ (3,804,449)	$ (3,133,140)	$ (12,739,729)	$ (804,617)	$ (1,377,211)	$ (16,828)	$ (21,875,974)
(26) Net Cost of Service	$ 679,759,110	$ 257,739,888	$ 190,200,219	$ 52,524,678	$ 47,345,737	$ 89,190,155	$ 42,758,434	$ 679,759,110
(27) Billing Units		5,943,619,831	5,943,619,831	5,943,619,831	5,943,619,831	5,308,105	5,308,105	
(28) Unit Costs		0.043364127	0.032000738	0.008837153	0.007965808	$ 0.55	$ 0.26	$ 0.82

Customer Cost	$	0.82
Infrastructure Energy Cost	$	0.06017
Variable Energy Cost	$	0.03200

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2022

Rate RS

		Production		Transmission	Distribution		Customer Service Expenses	
Description	**Amount**	**Demand-Related**	**Energy-Related**	**Demand-Related**	**Demand-Related**	**Customer-Related**	**Customer-Related**	**Total**
(1) Rate Base	$ 1,830,420,621	$ 957,680,114	$ 28,168,165	$ 164,114,791	$ 247,962,447	$ 428,194,391	$ 4,300,712	$ 1,830,420,621
(2) Rate Base Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(3) Rate Base as Adjusted	$ 1,830,420,621	$ 957,680,114	$ 28,168,165	$ 164,114,791	$ 247,962,447	$ 428,194,391	$ 4,300,712	$ 1,830,420,621
(4) Rate of Return	2.78%	2.78%	2.78%	2.78%	2.78%	2.78%	2.78%	
(5) Return	$ 50,858,000	$ 26,609,018	$ 782,649	$ 4,559,908	$ 6,889,604	$ 11,897,326	$ 119,495	$ 50,858,000
(6) Interest Expenses	$ 40,093,733	$ 20,977,130	$ 616,999	$ 3,594,788	$ 5,431,396	$ 9,379,217	$ 94,203	$ 40,093,733
(7) Net Income	$ 10,764,267	$ 5,631,888	$ 165,650	$ 965,120	$ 1,458,208	$ 2,518,109	$ 25,291	$ 10,764,267
(8) Income Taxes	$ 10,344,723	$ 5,412,382	$ 159,194	$ 927,504	$ 1,401,373	$ 2,419,964	$ 24,306	$ 10,344,723
(9) Operation and Maintenance Expenses	$ 283,536,077	$ 53,383,070	$ 142,877,811	$ 16,306,536	$ 14,564,398	$ 35,738,396	$ 20,665,865	$ 283,536,077
(10) Depreciation Expenses	141,321,587	101,457,547	-	6,895,148	12,142,048	20,826,845	-	$ 141,321,587
(11) Other Taxes	22,018,306	12,011,678	-	1,886,754	2,989,992	5,129,882	-	$ 22,018,306
(12) Curtailable Service Rider	1,177,704	616,178	18,124	105,593	159,541	275,503	2,767	$ 1,177,704
(13) Expense Adjustments - Prod. Demand	-	-	-	-	-	-	-	$ -
(14) Expense Adjustments - Energy	-	-	-	-	-	-	-	$ -
(15) Expense Adjustments - Trans. Demand	-	-	-	-	-	-	-	$ -
(16) Expense Adjustments - Distribution	-	-	-	-	-	-	-	$ -
(17) Expense Adjustments - Other	203,392	106,415	3,130	18,236	27,553	47,580	478	$ 203,392
(18) Revenue Adjustments	-	-	-	-	-	-	-	$ -
(19) Proforma Adjustments - Total	$ 203,392	$ 106,415	$ 3,130	$ 18,236	$ 27,553	$ 47,580	$ 478	$ 203,392
(20) Total Cost of Service	$ 509,459,788	$ 199,596,287	$ 143,840,907	$ 30,699,678	$ 38,174,510	$ 76,335,495	$ 20,812,911	$ 509,459,788
(21) Less: Misc Revenue - Prod Demand	$ (317,551)	$ (317,551)						$ (317,551)
(22) Less: Misc Revenue - Energy	(12,366,967)	-	(12,366,967)	-	-	-	-	$ (12,366,967)
(23) Less: Misc Revenue - Transmission	(5,722,158)	-	-	(5,722,158)	-	-	-	$ (5,722,158)
(24) Less: Misc Revenue - Other	(5,984,316)	(3,131,007)	(92,092)	(536,551)	(810,680)	(1,399,924)	(14,061)	$ (5,984,316)
(25) Less: Misc Revenue - Total	(24,390,993)	(3,448,559)	(12,459,059)	(6,258,710)	(810,680)	(1,399,924)	(14,061)	$ (24,390,993)
(26) Net Cost of Service	$ 485,068,795	$ 196,147,729	$ 131,381,848	$ 24,440,968	$ 37,363,830	$ 74,935,571	$ 20,798,850	$ 485,068,795
(27) Billing Units		4,049,109,440	4,049,109,440	4,049,109,440	4,049,109,440	4,530,684	4,530,684	
(28) Unit Costs		$ 0.04844	$ 0.03245	$ 0.00604	$ 0.00923	$ 0.54	$ 0.15	$ 0.69

Customer Cost	$	0.69
Infrastructure Energy Cost	$	0.06371
Variable Energy Cost	$	0.03245

Exhibit WSS-3

Cost Support for General Time-of-Date Service Rates

Kentucky Utilities Company
Louisville Gas and Electric Company
Cost Support of GSTOD

	Kentucky Utilities Company			Louisville Gas and Electric Company		
Infrastructure Cost	**Costs**	**kWH**	**Unit Cost**	**Costs**	**kWH**	**Unit Cost**
Production Peak	$ 104,295,799.93	334,720,632	$ 0.31159	$ 75,472,056	238,769,104	$ 0.31609
Transmission	$ 54,584,113.90	1,678,149,896	$ 0.03253	$ 43,589,923	1,197,088,880	$ 0.03641
Distribution	$ 39,953,463.73	1,678,149,896	$ 0.02381	$ 39,917,171	1,197,088,880	$ 0.03335
Total Infrastructure Cost per kWh			$ 0.10725			$ 0.13280
Peak			$ 0.31159			$ 0.31609
Off-Peak			$ 0.05633			$ 0.06976
GTOD-E						
Proposed GS Infrastructure Charge			$ 0.09216			$ 0.09015
Peak			**$ 0.26776**			**$ 0.21457**
Off-Peak			**$ 0.04841**			**$ 0.04735**
Proposed Residential Infrastructure Charge			$ 0.06750			$ 0.07237
Proposed General Service Infrastructure Charge			$ 0.09216			$ 0.09015
RTOD						
Peak			$ 10.37			$ 9.43
Base			$ 4.01			$ 4.31
Infrastructure Energy			$ 0.02683			$ 0.02095
GTOD-D						
Peak			**$ 14.16**			**$ 11.75**
Base			**$ 5.47**			**$ 5.37**
Infrastructure Energy			**$ 0.03663**			**$ 0.02610**

Exhibit WSS-4

Cost Support for LED Fixture and Underground Pole Charges

Kentucky Utilities Company

Cost Support for LED Fixtures and Underground Poles

Company	OH/UG Poles	Property Type	kW per Light	Lumen	Useful Life	Total Installed Cost	Fixed Carrying Charge	Annual Carrying Cost	Annual Non-Fixture Maintenance Cost	Annual Distribution Energy @ LE Rate $ 0.07178	Total Annual Revenue Requirement	Monthly Rate
KU	OH	Cobra	0.071	6000-8200	25	$ 633.36	14.50%	$ 91.82	$ 2.71	$ 20.39	$ 114.91	$ 9.58
KU	OH	Cobra	0.122	13000-16500	25	$ 695.99	14.50%	$ 100.89	$ 2.71	$ 35.03	$ 138.63	$ 11.55
KU	OH	Cobra	0.194	22000-29000	25	$ 826.97	14.50%	$ 119.88	$ 2.71	$ 55.70	$ 178.29	$ 14.86
KU	OH	Open Bottom	0.048	4500-6000	15	$ 451.89	17.16%	$ 77.56	$ 2.71	$ 13.78	$ 94.05	$ 7.84
KU	OH	Cobra	0.022	2500-4000	25	$ 620.40	14.50%	$ 89.94	$ 2.71	$ 6.32	$ 98.96	$ 8.25
KU	OH	Directional (Flood)	0.030	4500-6000	25	$ 815.79	14.50%	$ 118.26	$ 2.71	$ 8.61	$ 129.58	$ 10.80
KU	OH	Directional (Flood)	0.096	14000-17500	25	$ 842.79	14.50%	$ 122.18	$ 2.71	$ 27.56	$ 152.44	$ 12.70
KU	OH	Directional (Flood)	0.175	22000-28000	25	$ 881.18	14.50%	$ 127.74	$ 2.71	$ 50.25	$ 180.69	$ 15.06
KU	OH	Directional (Flood)	0.297	35000-50000	25	$ 1,200.38	14.50%	$ 174.01	$ 2.71	$ 85.27	$ 261.99	$ 21.83
KU	UG	Cobra	0.022	2500-4000	25	$ 289.67	14.50%	$ 41.99	$ -	$ 6.32	$ 48.31	$ 4.03
KU	UG	Cobra	0.071	6000-8200	25	$ 302.63	14.50%	$ 43.87	$ -	$ 20.39	$ 64.26	$ 5.35
KU	UG	Cobra	0.122	13000-16500	25	$ 365.26	14.50%	$ 52.95	$ -	$ 35.03	$ 87.979	$ 7.33
KU	UG	Cobra	0.194	22000-29000	25	$ 496.24	14.50%	$ 71.94	$ -	$ 55.70	$ 127.64	$ 10.64
KU	UG	Colonial	0.044	4000-7000	25	$ 503.67	14.50%	$ 73.02	$ -	$ 12.63	$ 85.65	$ 7.14
KU	UG	Acorn	0.040	4000-7000	25	$ 639.82	14.50%	$ 92.75	$ -	$ 11.48	$ 104.24	$ 8.69
KU	UG	Contemporary	0.057	4000-7000	25	$ 450.57	14.50%	$ 65.32	$ -	$ 16.37	$ 81.68	$ 6.81
KU	UG	Contemporary	0.087	8000-11000	25	$ 503.35	14.50%	$ 72.97	$ -	$ 24.98	$ 97.95	$ 8.16
KU	UG	Contemporary	0.143	13500-16500	25	$ 548.95	14.50%	$ 79.58	$ -	$ 41.06	$ 120.64	$ 10.05
KU	UG	Contemporary	0.220	21000-28000	25	$ 771.72	14.50%	$ 111.87	$ -	$ 63.17	$ 175.04	$ 14.59
KU	UG	Contemporary	0.380	45000-50000	25	$ 926.55	14.50%	$ 134.32	$ -	$ 109.11	$ 243.42	$ 20.29
KU	UG	Directional (Flood)	0.030	4500-6000	25	$ 617.89	14.50%	$ 89.57	$ -	$ 8.61	$ 98.19	$ 8.18
KU	UG	Directional (Flood)	0.096	14000-17500	25	$ 644.88	14.50%	$ 93.49	$ -	$ 27.56	$ 121.05	$ 10.09
KU	UG	Directional (Flood)	0.175	22000-28000	25	$ 683.27	14.50%	$ 99.05	$ -	$ 50.25	$ 149.30	$ 12.44
KU	UG	Directional (Flood)	0.297	35000-50000	25	$ 1,002.48	14.50%	$ 145.33	$ -	$ 85.27	$ 230.60	$ 19.22
KU	UG	Victorian	0.079	5800	25	$ 1,639.43	14.50%	$ 237.66	$ -	$ 22.68	$ 260.35	$ 21.70

Company	OH/UG Poles	Property Type	Wattage	Lumen	Useful Life	Total Installed Cost	Fixed Carrying Charge	Annual Carrying Cost	Annual Non-Fixture Maintenance Cost	Total Annual Revenue Requirement	Monthly Rate
KU	Poles	Cobra			28	$ 941.30	15.99%	$ 150.54	$ 2.71	$ 153.25	$ 12.77
KU	Poles	Contemporary			28	$ 869.50	15.99%	$ 139.06	$ 2.71	$ 141.76	$ 11.81
KU	Poles	Post Top - Decorative Smooth			28	$ 641.21	15.99%	$ 102.55	$ 2.71	$ 105.25	$ 8.77
KU	Poles	Post Top - Historic Fluted			28	$ 1,083.67	15.99%	$ 173.31	$ 2.71	$ 176.01	$ 14.67
KU	Poles	Wood Pole			28	$ 714.90	14.07%	$ 100.57	$ 2.71	$ 103.28	$ 8.61

Louisville Gas & Electric Company

Cost Support for LED Fixtures and Underground Poles

Company	OH/UG Poles	Property Type	kW per Light	Lumen	Useful Life	Total Installed Cost	Fixed Carrying Charge	Annual Carrying Cost	Annual Non-Fixture Maintenance Cost	Annual Distribution Energy @ LE Rate $ 0.07293	Total Annual Revenue Requirement	Monthly Rate
LG&E	OH	Cobra	0.071	5500-8200	25	$ 677.69	14.71%	$ 99.67	$ 5.25	$ 20.71	$ 125.63	$ 10.47
LG&E	OH	Cobra	0.122	13000-16500	25	$ 738.69	14.71%	$ 108.64	$ 5.25	$ 35.59	$ 149.48	$ 12.46
LG&E	OH	Cobra	0.194	22000-29000	25	$ 866.26	14.71%	$ 127.40	$ 5.25	$ 56.59	$ 189.24	$ 15.77
LG&E	OH	Open Bottom	0.048	4500-6000	15	$ 542.59	17.37%	$ 94.27	$ 5.25	$ 14.00	$ 113.52	$ 9.46
LG&E	OH	Cobra	0.022	2500-4000	25	$ 665.07	14.71%	$ 97.81	$ 5.25	$ 6.42	$ 109.48	$ 9.12
LG&E	OH	Directional (Flood)	0.03	4500-6000	25	$ 885.87	14.71%	$ 130.29	$ 5.25	$ 8.75	$ 144.29	$ 12.02
LG&E	OH	Directional (Flood)	0.096	14000-17500	25	$ 912.16	14.71%	$ 134.15	$ 5.25	$ 28.01	$ 167.41	$ 13.95
LG&E	OH	Directional (Flood)	0.175	22000-28000	25	$ 949.56	14.71%	$ 139.65	$ 5.25	$ 51.05	$ 195.95	$ 16.33
LG&E	OH	Directional (Flood)	0.297	35000-50000	25	$ 1,260.44	14.71%	$ 185.38	$ 5.25	$ 86.64	$ 277.26	$ 23.11
LG&E	UG	Cobra	0.022	2500-4000	25	$ 308.90	14.71%	$ 45.43	$ -	$ 6.42	$ 51.85	$ 4.32
LG&E	UG	Cobra	0.071	5500-8200	25	$ 321.52	14.71%	$ 47.29	$ -	$ 20.71	$ 68.00	$ 5.67
LG&E	UG	Cobra	0.122	13000-16500	25	$ 382.52	14.71%	$ 56.26	$ -	$ 35.59	$ 91.848	$ 7.65
LG&E	UG	Cobra	0.194	22000-29000	25	$ 510.09	14.71%	$ 75.02	$ -	$ 56.59	$ 131.61	$ 10.97
LG&E	UG	Colonial	0.044	4000-7000	25	$ 517.33	14.71%	$ 76.09	$ -	$ 12.84	$ 88.92	$ 7.41
LG&E	UG	Acorn	0.04	4000-7000	25	$ 510.09	14.71%	$ 75.02	$ -	$ 11.67	$ 86.69	$ 7.22
LG&E	UG	Contemporary	0.057	4000-7000	25	$ 465.61	14.71%	$ 68.48	$ -	$ 16.63	$ 85.11	$ 7.09
LG&E	UG	Contemporary	0.087	8000-11000	25	$ 517.02	14.71%	$ 76.04	$ -	$ 25.38	$ 101.42	$ 8.45
LG&E	UG	Contemporary	0.143	13500-16500	25	$ 561.43	14.71%	$ 82.57	$ -	$ 41.72	$ 124.29	$ 10.36
LG&E	UG	Contemporary	0.22	21000-28000	25	$ 778.39	14.71%	$ 114.48	$ -	$ 64.18	$ 178.66	$ 14.89
LG&E	UG	Contemporary	0.38	45000-50000	25	$ 929.19	14.71%	$ 136.66	$ -	$ 110.85	$ 247.51	$ 20.63
LG&E	UG	Directional (Flood)	0.03	4500-6000	25	$ 617.43	14.71%	$ 90.81	$ -	$ 8.75	$ 99.56	$ 8.30
LG&E	UG	Directional (Flood)	0.096	14000-17500	25	$ 643.72	14.71%	$ 94.67	$ -	$ 28.01	$ 122.68	$ 10.22
LG&E	UG	Directional (Flood)	0.175	22000-28000	25	$ 681.12	14.71%	$ 100.17	$ -	$ 51.05	$ 151.22	$ 12.60
LG&E	UG	Directional (Flood)	0.297	35000-50000	25	$ 992.00	14.71%	$ 145.90	$ -	$ 86.64	$ 232.54	$ 19.38
LG&E	UG	Victorian	0.039	4000-7000	25	$ 2,051.33	14.71%	$ 301.70	$ -	$ 11.38	$ 313.07	$ 26.09
LG&E	UG	London	0.079	4000-7000	25	$ 2,101.72	14.71%	$ 309.11	$ -	$ 23.05	$ 332.15	$ 27.68

Company	OH/UG Poles	Property Type	Wattage	Lumen	Useful Life	Total Installed Cost	Fixed Carrying Charge	Annual Carrying Cost	Annual Non-Fixture Maintenance Cost	Total Annual Revenue Requirement	Monthly Rate
LG&E	Poles	Cobra			28	$ 1,878.32	16.82%	$ 315.87	$ 5.05	$ 320.92	$ 26.74
LG&E	Poles	Contemporary (Short)			28	$ 1,253.31	16.82%	$ 210.76	$ 5.05	$ 215.81	$ 17.98
LG&E	Poles	Contemporary (Tall)			28	$ 1,629.97	16.82%	$ 274.11	$ 5.05	$ 279.16	$ 23.26
LG&E	Poles	Post Top - Decorative Smooth			28	$ 1,109.18	16.82%	$ 186.53	$ 5.05	$ 191.58	$ 15.96
LG&E	Poles	Post Top - Historic Fluted			28	$ 1,375.23	16.82%	$ 231.27	$ 5.05	$ 236.32	$ 19.69
LG&E	Poles	Wood Pole			28	$ 559.68	14.28%	$ 79.92	$ 5.05	$ 84.97	$ 7.08

Exhibit WSS-5

Cost Support for LED Conversion Fee

Kentucky Utilities Company
Determination of Conversion Fee

Number of Fixtures	172,819		
2020 Net Book Value		$	73,343,106
Estimated NBV for Poles	53.54%	$	39,269,427
Estimated NBV for Fixtures		$	34,073,680
NBV per Fixture		$	197.16
5 Year Carrying Charge Rate			
Overall Rate of Return			7.206%
Depreciation			20.000%
Income Taxes			1.770%
Property Taxes			1.511%
Carrying Charge Rate			30.487%
Annual Conversion Fee		$	60.11
Monthly Conversion Fee		$	5.01
Salvage Portion of Conversion Fee		$	3.29
Revenue Portion of Conversion Fee		$	1.72

Louisville Gas & Electric Company
Determination of Conversion Fee

Number of Fixtures	88,567		
2020 Net Book Value		$	73,065,258
Estimated NBV for Poles	66.39%	$	48,506,556
Estimated NBV for Fixtures		$	24,558,702
NBV per Fixture		$	277.29
5 Year Carrying Charge Rate			
Overall Rate of Return			7.165%
Depreciation			20.000%
Income Taxes			1.768%
Property Taxes			1.718%
Carrying Charge Rate			30.651%
Annual Conversion Fee		$	84.99
Monthly Conversion Fee		$	7.08
Salvage Portion of Conversion Fee		$	4.62
Revenue Portion of Conversion Fee		$	2.46

Exhibit WSS-6

Westar's Residential Distributed Generation Rate

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC. & EVERGY KANSAS SOUTH, INC., d/b/a EVERGY KANSAS CENTRAL

(Name of Issuing Utility)

SCHEDULE RS-DG

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable)

Replacing Schedule RS-DG Sheet 1

which was filed September 28, 2018

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 4 Sheets

RESIDENTIAL STANDARD DISTRIBUTED GENERATION

AVAILABLE

Electric Service is available under this rate schedule at points on the Company's existing distribution system to customers using electric service for residential purposes. Any customer-generator operating or adding generation under an interconnection agreement connecting to Evergy Kansas Central's distribution system after October 1, 2018 must take service under this rate schedule.

APPLICABLE

Applicable to residential customers that have dwelling unit(s) each having separate kitchen facilities, sleeping facilities, living facilities and permanent provisions for sanitation. This rate schedule is restricted to residential electric service used principally for domestic purposes in customer's household, home, detached garage on the same premise as customer's home, or place of dwelling for the maintenance or improvement of customer's quality of life. Service to customers in rural areas through a single meter under this schedule may also use electric service in farm buildings for ordinary farm use providing that such buildings are adjacent to the customer's dwelling unit. However, this schedule is not applicable for crop irrigation, commercial dairies, hatcheries, feed lots, feed mills or any other commercial enterprise. This schedule is not applicable to backup, breakdown, standby, supplemental, short term, resale or shared electric service.

CHARACTER OF SERVICE

Alternating current, 60 hertz, single phase, at nominal voltages of 120 or 120/240 volts.

Issued ____________
Month Day Year

Effective August 6 2019
Month Day Year

By ____________

Darrin Ives, Vice President

19-WSEE-474-TAR
Approved JWP
Kansas Corporation Commission
August 6, 2019
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC. & EVERGY KANSAS SOUTH, INC., d/b/a EVERGY KANSAS CENTRAL — SCHEDULE RS-DG

(Name of Issuing Utility)

Replacing Schedule RS-DG Sheet 2

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable)

which was filed September 28, 2018

No supplement or separate understanding shall modify the tariff as shown hereon

RESIDENTIAL STANDARD DISTRIBUTED GENERATION

ELECTRIC SERVICE

NET MONTHLY BILL

BASIC SERVICE FEE $14.50

ENERGY CHARGE 4.5840¢ per kWh

DEMAND CHARGE

Winter Period - Demand set in the billing months of October through May.
$3.00 per kW

Summer Period - Demand set in the billing months of June through September.
$9.00 per kW

Plus all applicable adjustments and surcharges.

MINIMUM MONTHLY BILL

The Basic Service Fee, plus the minimum specified in the Electric Service Agreement, plus all applicable adjustments and surcharges.

BILLING DEMAND

Customer's average kilowatt load during the 60-minute period of maximum use that occurs in the demand billing period during the month.

DETERMINATION OF PEAK BILLING PERIOD

For purposes of this rate schedule, the demand billing period shall be daily the hours of 2:00 pm through 7:00 pm Central Time, except for weekends, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Issued ____________
Month Day Year

Effective August 6 2019
Month Day Year

By ____________

Darrin Ives, Vice President

19-WSEE-474-TAR
Approved JWP
Kansas Corporation Commission
August 6, 2019
/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC. & EVERGY KANSAS SOUTH, INC., d/b/a EVERGY KANSAS CENTRAL — SCHEDULE RS-DG

(Name of Issuing Utility)

Replacing Schedule RS-DG Sheet 3

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) — which was filed September 28, 2018

No supplement or separate understanding shall modify the tariff as shown hereon

RESIDENTIAL STANDARD DISTRIBUTED GENERATION

ADJUSTMENTS AND SURCHARGES

The rates hereunder are subject to adjustment as provided in the following schedules:

1. Retail Energy Cost Adjustment
2. Property Tax Surcharge
3. Transmission Delivery Charge
4. Environmental Cost Recovery Rider
5. Renewable Energy Program Rider
6. Energy Efficiency Rider
7. Tax Adjustment

Plus all applicable adjustments and surcharges.

DEFINITIONS AND CONDITIONS

1. The initial term of service under this rate schedule shall be one year. Company reserves the right to require the customer to execute an Electric Service Agreement with an additional charge, or special minimum and or a longer initial term when additional facilities are required to serve such customer.

2. A Customer-Generator is the owner or operator of a facility which:

   a. Is located on premises owned, operated, leased, or otherwise controlled by the Customer-Generator and provides power to a facility located on that same premise;
   b. Is interconnected and operates in parallel phase and synchronization with the Company facilities;
   c. Is intended primarily to offset part or all of the Customer-Generator's own electrical energy requirements; and
   d. Contains a mechanism, approved by the Company that automatically disables the unit and interrupts the flow of electricity back onto the Company's electric lines in the event that service to the Customer-Generator is interrupted.

Issued ______ Month Day Year

Effective August 6 2019
Month Day Year

By [signature]
Darrin Ives, Vice President

19-WSEE-474-TAR
Approved JWP
Kansas Corporation Commission
August 6, 2019
/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC. & EVERGY KANSAS SOUTH, INC., d/b/a EVERGY KANSAS CENTRAL
(Name of Issuing Utility)

SCHEDULE RS-DG

Replacing Schedule RS-DG Sheet 4

EVERGY KANSAS CENTRAL RATE AREA
(Territory to which schedule is applicable)

which was filed September 28, 2018

No supplement or separate understanding
shall modify the tariff as shown hereon

RESIDENTIAL STANDARD DISTRIBUTED GENERATION

3. Individual motor units shall not exceed five horsepower, unless otherwise agreed upon prior to installation.

4. Service under this rate schedule is subject to Company's General Terms and Conditions presently on file with the State Corporation Commission of Kansas and any modification subsequently approved.

5. All provisions of this rate schedule are subject to changes made by order of the regulatory authority having jurisdiction.

Issued ______
Month Day Year

Effective August 6 2019
Month Day Year

By Darrin Ives
Darrin Ives, Vice President

19-WSEE-474-TAR
Approved JWP
Kansas Corporation Commission
August 6, 2019
/s/ Lynn Retz

Exhibit WSS-7

Kansas Corporation Commission's
Order Regarding Distributed Generation

20170921102409
Kansas Corporation Commission

BEFORE THE STATE CORPORATION COMMISSION OF THE STATE OF KANSAS

Before Commissioners: Pat Apple, Chairman
Shari Feist Albrecht
Jay Scott Emler

In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers.	)))	Docket No. 16-GIME-403-GIE

FINAL ORDER

This matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision. Having reviewed the pleadings and record, the Commission makes the following findings:

I. Background

1. On July 12, 2016, the Commission issued an Order Opening General Investigation to examine various issues surrounding rate structure for distributed generation (DG) customers.[1] The Commission stated its intent to have a thorough and thoughtful discussion of the appropriate rate structure for DG including the quantifiable costs and quantifiable benefits of DG.[2] The Commission named all Kansas electric public utilities, subject to the Commission's jurisdiction over retail rates,[3] as parties to the docket and also granted parties an opportunity to provide evidence showing that costs and benefits can be quantified and allocated in a manner which will result in just and reasonable rates for DG customers.[4]

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[1] Order Opening General Investigation, p. 5 (July 12, 2016).
[2] *Id.*
[3] Westar Energy, Inc. and Kansas Gas and Electric Company (collectively, Westar), Kansas City Power & Light Company (KCP&L), Southern Pioneer Electric Company (Southern Pioneer), Midwest Energy, Inc. (Midwest Energy), Empire District Electric Company (Empire).
[4] Order Opening General Investigation, p. 5.

2. On July 14, 2017, the Commission issued orders granting intervention to Cromwell Environmental, Inc. (Cromwell), the Citizens Utility Ratepayer Board (CURB), The Alliance for Solar Choice, Sunflower Electric Power Corporation (Sunflower) and Mid-Kansas Electric Company (Mid-Kansas), and Brightergy, LLC (Brightergy).

3. On September 1, 2016, the Commission issued orders granting intervention to the Kansas Electric Cooperatives, Inc. (KEC), the Climate and Energy Project (CEP), and IBEW Local Union No. 304 (IBEW).

4. On September 29, 2016, the Commission issued an order granting intervention to United Wind, Inc. (United Wind).

5. On February 16, 2017, the Commission issued an Order Setting Procedural Schedule. The order set a schedule for the parties to file comments, engage in roundtable discussions, and participate in an evidentiary hearing.[5]

6. On March 17, 2017, Midwest Energy,[6] Southern Pioneer,[7] which was joined by KEC, Westar,[8] Brightergy,[9] CEP,[10] KCP&L,[11] United Wind,[12] Cromwell,[13] Sunflower and Mid-

[5] Order Setting Procedural Schedule, p. 3 (Feb. 16, 2017).
[6] Initial Comments of Midwest Energy, Inc., (March 17, 2017) (Initial Comments Midwest Energy).
[7] Initial Comments of Southern Pioneer Electric Company Joined by the Kansas Electric Cooperatives, Inc., (March 17, 2017) (Initial Comments Southern Pioneer and KEC).
[8] Initial Comments of Westar Energy, Inc. and Kansas Gas and Electric Company Regarding Cost-Based Rates for Customers with Distributed Generation, (March 17, 2017) (Initial Comments Westar).
[9] Brightergy elected not to provide a sponsoring witness for its comments and later withdrew its comments from the evidentiary record. Brightergy requested its comments be included with the public comments.
[10] Testimony of Dorothy Barnett on Behalf of the Climate + Energy Project, (March 17, 2017) (Initial Comments CEP).
[11] Initial Comments of Kansas City Power & Light Company, (March 17, 2017) (Initial Comments KCP&L).
[12] United Wind elected not to provide a sponsoring witness for its comments and later withdrew its comments from the evidentiary record. United Wind requested its comments be included with the public comments.
[13] Initial Comments of Cromwell Environmental, (March 17, 2017) (Initial Comments Cromwell).

Kansas,[14] CURB,[15] Empire,[16] and Commission Utilities Staff[17] (Staff) filed their initial Comments.

7. On May 5, 2017, Southern Pioneer,[18] Westar,[19] Midwest,[20] Staff,[21] Sunflower and Mid-Kansas,[22] KCP&L,[23] Empire,[24] Brightergy,[25] Cromwell,[26] IBEW 304,[27] and CEP[28] filed their reply comments.

8. On June 16, 2017, Staff, Westar, KCP&L, Sunflower, Mid-Kansas, Southern Pioneer, KEC, Midwest Energy, Empire, Brightergy, United Wind, and IBEW 304 (Joint Movants) filed a Motion to Approve Non-Unanimous Stipulation and Agreement (S&A).

9. Also on June 16, 2017, the Parties filed a List of Contested Issues.

10. On June 20, 2017, Westar,[29] KCP&L,[30] Southern Pioneer and KEC,[31] and Staff[32] filed testimony in support of the Non-Unanimous Stipulation and Agreement.

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[14] Initial Comments of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC, (March 17, 2017) (Initial Comments of Sunflower and Mid-Kansas).
[15] Notice of Filing of CURB'S Initial Comments, (March 17, 2017) (Initial Comments CURB).
[16] Affidavit of William G. Eichman on Behalf of The Empire District Electric Company, (March 17, 2017) (Initial Comments Empire).
[17] Notice of Filing Staff's Verified Initial Comments (March 17, 2017) (Initial Comments Staff).
[18] Reply Comments of Southern Pioneer Electric Company, (May 5, 2017) (Reply Comments Southern Pioneer).
[19] Reply Comments of Westar Energy, Inc. and Kansas Gas and Electric Company Regarding Cost-Based Rates for Customers with Distributed Generation, (May 5, 2017) (Reply Comments Westar).
[20] Reply Comments of Midwest Energy, Inc., (May 5, 2017) (Reply Comments Midwest).
[21] Notice of Filing Staff's Verified Reply Comments, (May 5, 2017) (Reply Comments Staff).
[22] Reply Comments of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC, (May 5, 2017) (Reply Comments Sunflower and Mid-Kansas).
[23] Reply Comments of Kansas City Power & Light Company, (May 5, 2017) (Reply Comments KCP&L).
[24] Affidavit of William G. Eichman Supporting Reply Comments on Behalf of The Empire District Electric Company, (May 5, 2017) (Reply Comments Empire).
[25] Brightergy elected not to provide a sponsoring witness for its comments and later withdrew its comments from the evidentiary record. Brightergy requested its comments be included with the public comments.
[26] Reply Comments of Cromwell Environmental, (May 5, 2017) (Reply Comments Cromwell).
[27] IBEW 304 elected not to provide a sponsoring witness for its comments and later withdrew its comments from the evidentiary record. IBEW 304 requested its comments be included with the public comments.
[28] Reply Comments of Climate and Energy, (May 5, 2017) (Reply Comments CEP).
[29] Testimony of Jeff Martin in Support of Stipulation and Agreement – Westar Energy, Inc. (June 20, 2017) (Testimony in Support Martin); On June 26, 2017, Westar late filed the Rebuttal Testimony of Ahmad Faruqui in Support of Stipulation and Agreement (Testimony in Support Faruqui).
[30] Testimony in Support of the Settlement Agreement of Bradley D. Lutz on behalf of Kansas City Power & Light Company (June 20, 2017) (Testimony in Support Lutz).

11. On June 20, 2017, CURB,[33] Cromwell,[34] and CEP,[35] (collectively the Opposing Parties) filed testimony in opposition to the Non-Unanimous Stipulation and Agreement.

II. Legal Standard

12. Every public utility in Kansas is required to provide reasonably efficient and sufficient service and establish just and reasonable rates.[36] Just and reasonable rates are those that fall within a "zone of reasonableness," which balances the interests of present and future ratepayers, and the public interest.[37] The Kansas Supreme Court has recognized that "the touchstone of public utility law is the rule that one class of consumers shall not be burdened with costs created by another class."[38] The Commission may in addition to cost-causation, consider matters of public policy, such as gradualism to minimize rate shock, revenue stability for the company, economic development, and energy efficiency.[39] Both federal and state courts have been clear that rates must be based on costs and supported by substantial competent evidence.[40] Substantial competent evidence is that which possesses something of substance and relevant consequence, and which furnishes a substantial basis of fact from which the issues can

[31] Testimony in Support of Stipulation and Agreement Prepared by Richard J. Macke (June 20, 2017) (Testimony in Support Macke).
[32] Testimony in Support of the Non-Unanimous Stipulation and Agreement Prepared by Robert H. Glass (June 20, 2017) (Testimony in Support Glass).
[33] Testimony in Opposition to Non-Unanimous Stipulation and Agreement of Cary Catchpole on Behalf of CURB (Jun. 20, 2017) (Testimony in Opposition Catchpole); Testimony in Opposition to Non-Unanimous Stipulation and Agreement of Brian Kalcic on Behalf of CURB (Jun. 20, 2017) (Testimony in Opposition Kalcic).
[34] Testimony of Aron Cromwell in Opposition to Non-Unanimous Stipulation and Agreement (Jun. 20, 2017) (Testimony in Opposition Cromwell).
[35] Testimony of the Climate and Energy Project Addressing Non-Unanimous Settlement (Jun. 20, 2017) (Testimony in Opposition CEP).
[36] K.S.A. 66-101b.
[37] *Kansas Gas and Elec. Co. v. Kansas Corp. Comm'n.*, 239 Kan. 483, 488 (1986).
[38] *Jones v. Kansas Gas & Electric Co.*, 222 Kan. 390, 401 (1977).
[39] Docket No. 12-KCPE-764-RTS (Aug. 22, 2012); Docket No. 16-KCPE-446-TAR (Jun. 22, 2017); *See* also, *Midwest Gas Users Ass'n v. Kansas Corp. Comm'n*, 3 Kan. App.2d 376, 380 (1979).
[40] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Kansas Gas and Electric Co.*, 239 Kan. At 501; *Zinke & Trumbo, Ltd. v. State Corp. Comm'n*, 242 Kan. 470, 475 (1988).

reasonably be resolved.[41] A decision of the Commission is unsupported by substantial competent evidence "only when the evidence shows the [Commission's] determination 'is so wide of the mark as to be outside the realm of fair debate.'"[42] The Kansas Supreme Court has also stated that the Commission "is not obligated to render its finding of fact in minute detail ... [h]owever, we require its findings to be specific enough to allow judicial review of the reasonableness of the order."[43]

13. The law generally favors the compromise and settlement of disputes.[44] However, the Commission must make an independent finding that the settlement is supported by substantial competent evidence in the record as a whole, that the settlement will establish just and reasonable rates, and the settlement is in the public interest.[45]

14. The Commission has established a five-part test to determine the reasonableness of proposed settlement agreements. The five parts are rooted in the Commission's organic statutes,[46] the Kansas Administrative Procedure Act,[47] and the Kansas Act for Judicial Review and Civil Enforcement of Agency Actions.[48] The five parts are:

a. Whether there was an opportunity for the opposing party to be heard on their reasons for opposition to the stipulation and agreement;

b. whether the stipulation and agreement is supported by substantial competent evidence;

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[41] *Farmland Indus., Inc. v. Kansas Corp. Comm'n.*, 25 Kan.App.2d 849, 852 (1999).
[42] *Zinke & Trumbo, Ltd. v. Kansas Corp. Comm'n*, 242 Kan. 470, 474 (1988) (quoting *Kansas-Nebraska Natural Gas Co. v. Kansas Corp. Comm'n*, 217 Kan. 604, 617).
[43] *Id.* at 475.
[44] *Krantz v. Univ. of Kansas*, 271 Kan. 234, 241-42 (2001).
[45] *Citizens' Utility Ratepayer Board v. Kansas Corp. Comm'n.*, 28 Kan.App.2d 313, 316, (2000) *rev. denied* March 20, 2001.
[46] *See* K.S.A. 66-101b (providing the Commission with the power to "require all electric public utilities governed by this act to establish and maintain just and reasonable rates").
[47] *See,* K.S.A. 77-501 *et seq.*
[48] *See,* K.S.A. 77-601 *et seq.*

c. whether the stipulation and agreement conforms with applicable law;

d. whether the stipulation and agreement results in just and reasonable rates;

e. whether the results of the stipulation and agreement are in the public interest, including the interest of the customers represented by the party not consenting to the agreement.[49]

III. Findings and Conclusions

15. The Commission finds the intent and purpose of this general investigation has shifted slightly from when it was first opened. Staff initially stated the goal of this generic docket was to determine the appropriate rate structure for DG customers by evaluating the costs and benefits of DG, as well as by examining potential rate design alternatives for DG customers.[50] Though Staff recommended the Commission not change current rates through this proceeding, Staff did recommend the Commission make its findings in this docket binding, with specific tariff changes to be made in utility-specific docket filings.[51] However, the testimony in the evidentiary hearing suggested the parties were less interested in binding action by the Commission and more interested in guidance from the Commission regarding the appropriate direction of DG rate design.[52] This position was later repeated during briefing.[53]

[49] Order Approving Contested Settlement Agreement, Docket No. 08-ATMG-280-RTS, p. 5 (May 12, 2008).
[50] Staff's Report and Recommendation p. 8 (March 11, 2016).
[51] *Id.* at pp. 7-8.
[52] Tr. Vol. 1, p. 177 lns. 18-24; p. 178 lns. 16-19; pp. 126-127; pp. 178-179; pp. 180-82; p. 183 lns. 4-20; Tr. Vol. 2, p. 335.
[53] Reply Brief of Commission Staff, pp.6-7 (Aug. 25, 2017) (Nothing in the S&A limits or restricts a utility or the Commission to using a certain rate design. As discussed at hearing, Staff views the enumeration of rate design option in Paragraph 11 of the Stipulation and Agreement as merely that: options; not prescriptive requirements); Reply Brief of Citizens' Utility Ratepayer Board, p. 10 (Aug. 25, 2017); Post-Hearing Reply Brief of Kansas City Power & Light Company, p. 12 (Aug. 25, 2017).

16. With this request for guidance in mind, the Commission reviews the S&A utilizing the Commission's five-part question analysis of non-unanimous settlement agreements.

Whether there was an opportunity for the opposing party to be heard on their reasons for opposition to the stipulation and agreement?

17. The Commission finds the Opposing Parties each filed testimony in opposition to the S&A[54] and fully participated during the evidentiary hearing, including the cross-examination of the witnesses who testified in support of the S&A. The Commission finds therefore the Opposing Parties were granted an opportunity for their reasons for opposition to the S&A to be heard.

Whether the stipulation and agreement is supported by substantial competent evidence?

18. The Commission finds the S&A is specifically supported by the testimony of five witnesses through pre-filed supporting testimony,[55] live testimony at the evidentiary hearing, and the sworn pre-filed comments of the supporting parties.[56] Therefore, the Commission finds there to be sufficient evidence from which to make a decision.[57]

19. The S&A requests the Commission adopt nine substantive findings, which will be addressed below.

[54] *See Generally,* Testimony in Opposition CEP; Testimony in Opposition Cromwell; Testimony in Opposition Kalcic; Testimony in Opposition Catchpole.
[55] *See Generally,* Testimony in Support Glass; Testimony in Support Martin; Testimony in Support Faruqui; Testimony in Support Lutz; Testimony in Support Macke.
[56] *See,* Reply Comments Westar; Reply Comments Empire; Reply Comments KCP&L; Reply Comments Sunflower and Mid-Kansas; Reply Comments Midwest Energy; Reply Comments KEC; Reply Comments Southern Pioneer; Reply Comments Staff; Initial Comments Staff.
[57] The omission from this Order of any argument or portion of the record raised by the participants in their briefs does not mean that it has not been considered. All such arguments have been evaluated and found to either lack merit or significance to the extent that their inclusion would only tend to lengthen this Order without altering its substance or effect.

20. First, the Commission finds DG customers should be uniquely identified within the ratemaking process because of their potentially significant different usage characteristics.[58] The Commission finds the unique identification of DG customers within a class or sub-class is the key to properly recognizing the cost and quantifiable benefits of DG.[59] Utilities may create a separate residential class or sub-class for DG customers with their own rate design, which appropriately recovers the fixed costs of providing service to residential private DG customers, or a utility may continue to serve residential private DG customers within an existing residential rate class if the utility determines there are too few DG customers to justify a separate residential private DG class or sub-class or determines other justification exists to retain those customers in the existing rate class. A separate rate class for DG customers is not meant to punish those customers, rather such a class would serve to provide clarity for both utilities and customers.

21. Specific to Westar, the Commission finds Westar's Distributed Generation Residential Rate Schedule implemented in Westar's last rate case shall remain in place and effective for all residential customers installing distributed generation on or after October 28, 2015, and shall be treated as a separate class for purposes of future class cost of service studies and ratemaking generally.

22. Second, the Commission finds the current two-part residential rate design is problematic for utilities and residential private DG customers because DG customers use the

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[58] Initial Comments Staff, p. 16, ¶ 41; Reply Comments of Commission Staff, pp. 5-6; Comments of Cary Catchpole for the Citizens' Utility Ratepayer Board on Distributed Generation Policy Matters, p. 7, ¶ 11, pp. 8-9, ¶ 12-13, (Mar. 17, 2017); Comments of Brian Kalcic for the Citizens' Utility Ratepayer Board on Distributed Generation Rate Design, p. 8, (Mar. 17, 2017); Reply Comments Kalcic, pp. 2-4; Initial Comments Westar Energy, pp. 3-8, (Mar. 17, 2017); Reply Comments Westar, pp. 3-6, Initial Comments Empire District Electric Company, pp. 2-3, Reply Comments Empire, p. 1, pp. 3-4; Initial Comments Sunflower and Mid-Kansas, pp. 2-3; Initial Comments Southern Pioneer and KEC, p. 5, p. 7, ¶ 17; Reply Comments Southern Pioneer, p. 8, ¶¶ 19-20, (May 5, 2017); Initial Comments Midwest Energy, pp. 3, 5-6, and 8; Reply Comments Midwest Energy, pp. 2-4; Initial Comments KCP&L, p. 24; Reply Comments of KCP&L, p. 8.

[59] Direct Testimony in Support Lutz, p. 5.

electric grid as a backup system resulting in their consuming less energy than non-DG customers, which results in DG customers not paying the same proportion of fixed costs as non-DG customers.[60] The Commission finds DG customers are thus being subsidized by non-DG customers.[61]

23. Third, the Commission finds the following rate design options are appropriate for residential private DG customers, to allow utilities to better recover the costs of providing service to that class or sub-class of customers:

a. A cost of service based three-part rate consisting of a customer charge, demand charge, and energy charge;[62]

b. A grid charge based upon either the DG output or nameplate rating;[63] or

c. A cost of service-based customer charge that is tiered based upon a customer's capacity requirements.[64]

The Commission finds the above list is not meant to preclude a utility from proposing other appropriate rate designs within that individual utility's rate case proceeding, but rather recognizes that each utility might have different conditions and different needs.[65] Thus, the Commission finds the S&A allows flexibility for a variety of alternatives.[66]

24. The Commission's finding that the above rate designs are appropriate does not serve as a predetermination that the above rate designs will result in just and reasonable rates.

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[60] Initial Comments Staff, pp. 1-2; Initial Comments Westar Energy, pp. 7-13; Initial Comments Empire, p. 2; Initial Comments Southern Pioneer and KEC, pp. 5-7; Initial Comments Midwest Energy, ¶13; Initial Comments KCP&L, pp. 23-24; Initial Comments of Cary Catchpole for the CURB, ¶16; Initial Comments of Brian Kalcic for the CURB, ¶7.
[61] Initial Comments Staff, pp. 1-4; Tr. Vol. 1, p. 112.
[62] *See* Faruqui Initial Affidavit, at pp. 12-22, Brown Initial Affidavit, at pp. 41-42, Martin Initial Affidavit, at pp. 4-5, Faruqui Reply Affidavit, at pp. 1-2, Brown Reply Affidavit, at pp. 1-4, Martin Reply Affidavit, at pp. 5-6.
[63] Initial Comments of Southern Pioneer and KEC, p. 7; Initial Comments of Sunflower and Mid-Kansas, p. 4.
[64] Initial Comments CURB, p. 5; Initial Comments Empire, p. 3; Initial Comments Sunflower and Mid-Kansas, p. 4.
[65] Direct Testimony in Support Lutz, p. 7.
[66] Direct Testimony in Support Lutz, p. 7.

Rather, based upon the testimony on the record, the Commission interprets the S&A as requiring the sponsoring utility of a new DG rate design as having the burden to show that any proposed rate design will result in non-discriminatory, just and reasonable rates.[67]

25. Fourth, the Commission finds a customer education program must be implemented whenever new residential private DG rate structures are ordered, and that program should be completed as soon as practical after the Commission approves a new rate design.[68]

26. Fifth, the Commission finds rates for private residential DG customers should be cost-based and any unquantifiable value of resource approach should not be considered when setting rates. This is because cost-based rates are a fundamental attribute of good rate design as they allow the Commission to clearly identify quantifiable costs, which ensures rates for all customers are equitable while encouraging efficient use of resources and minimization of unnecessary cross-subsidization between customers.[69] This finding is consistent with the Commission's stated preference at the initiation of this investigation.[70] The Commission finds a class cost of service study provides sufficient support for design of a residential private DG tariff and no further study is necessary for the purpose of this docket because the class cost of service study takes into consideration benefits in the form of avoided costs.[71] However, this finding does not preclude any party from sponsoring any study it believes necessary to provide an evidentiary basis for its position in a general rate case. As in this docket, any study submitted should include only quantifiable market-based costs and benefits to the utility.

[67] *See,* K.S.A. 66-101b; K.A.R. 82-1-231.
[68] Direct Testimony in Support Lutz, p. 8.
[69] Direct Testimony in Support Lutz, p. 8.
[70] Order Opening General Investigation, p. 5.
[71] Initial Comments Staff, pp. 2-3

27. Sixth, the Commission finds that a value of resource study (i.e. cost-benefit analysis) is not required by the Commission at this time because, as testified by Staff, such studies have limited value because they return widely varying results and unnecessarily duplicate information already part of utility-specific class cost of service studies.[72] However, as indicated above, nothing herein precludes any party from developing any study it believes to be helpful to the Commission in establishing just and reasonable rates.

28. Seventh, the Commission finds DG rate design policy is best determined in this docket in order to provide certainty to all parties for the benefit of the orderly development of the private DG market in Kansas.[73] Without a determination by this Commission as to what an appropriate DG rate structure is, future rate design proposals will be undermined by the question of whether that particular rate design proposal is appropriate.[74] However, the Commission finds electric utilities that do not currently have DG tariffs shall have the option to propose DG tariffs consistent with the principles established in this general investigation in subsequent general rate case filings for approval by the Commission.

29. Eight, the Commission finds any DG-specific rate design implemented subsequent to this proceeding to serve residential private DG customers would apply to those customers adding DG systems on or after the effective date of those tariffs. Customers with distributed DG systems implemented and operating prior to that date and served by other rate designs will be allowed to remain on those preexisting rates until January 1, 2030, to the extent permitted by Kansas law. On and after January 1, 2030, all distributed generation customers will be subject to the then current residential DG rate design. The Commission further finds this S&A

[72] Initial Comments Staff, p. 8 (Mar. 17, 2017); Reply Comments Staff, p. 3; *See also,* Direct Testimony in Support Lutz, p. 8.
[73] Direct Testimony in Support Lutz, p. 9.
[74] *Id.*

term to be in the public interest because the term sets clear timeframes for implementation of any new DG structure while providing an important grandfathering period to provide a transition to the new rates, while protecting customers served under the old designs from unanticipated changes.[75] Likewise, the future closing date of January 1, 2030, is appropriate because it is the date set by statute when methods used to compensate excess generation under net meeting are unified under a single method.[76]

30. Specific to Westar, the Commission finds the settlement approved by the Commission in Westar's last general rate case regarding the creation of the "Residential Standard Distributed Generation" tariff remains in effect and customers who added DG on or after October 28, 2015, will be subject to the rate design change that occurs in future rate case dockets based on the policy established in this docket. The Commission finds this approach is appropriate because Westar's customers on its Residential Standard Distribution Generation tariff have received notice in Docket No. 15-WSEE-115-RTS and through Westar's outreach efforts.[77]

31. Ninth, the Commission finds this S&A provides guidance to the cooperatives that have elected to be self-regulated pursuant to K.S.A. 66-104d, but such self-regulated cooperatives shall not be bound by the S&A. The Commission finds such non-binding guidance to be in the public interest because it acknowledges that the cooperatives regulatory structure is different from the other public utilities subject to the S&A, while identifying how the S&A impacts them.[78]

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[75] Direct Testimony in Support Lutz, p. 10.
[76] *Id.*
[77] Tr. Vol. 1, p. 124.
[78] Direct Testimony in Support Lutz, p. 10.

Whether the stipulation and agreement conforms with applicable law?

32. Because of the rationale laid out below in paragraphs 34-37 the Commission concludes the S&A is in conformance with applicable law.

Whether the stipulation and agreement results in just and reasonable rates?

33. The Commission finds the S&A does not change rates or rate design for any customer[79] and thus the S&A results in the continuation of existing rates which the Commission has previously found to be just and reasonable.

Whether the results of the stipulation and agreement are in the public interest, including the interest of the customers represented by the party not consenting to the agreement?

34. The Commission interprets the S&A as a roadmap the electric utilities may pursue in future rate filings. The Commission interprets the S&A as establishing the following policies:

a. utilities may determine whether a separate rate class is appropriate;[80]
b. utilities may provide cost data for that class through a class cost of service study as required by Commission regulation; [81]
c. utilities are to provide cost data uniformly, excluding non-quantifiable societal benefits and externalities; and[82]
d. utilities may recommend the rate design appropriate for their electric system, service and customer base.[83]

[79] Direct Testimony in Support Glass, p. 7.
[80] S&A, ¶¶ 9-10.
[81] *Id.* at ¶ 13; *See also,* K.A.R. 82-1-231.
[82] S&A, at ¶ 14.
[83] *Id.* at ¶ 11.

35. The Commission finds the S&A is in the public interest because it establishes a policy framework for implementing DG. This framework provides a means through which DG issues as yet undetermined can be addressed in a utility-specific rate case docket.

36. Similarly, though the record evidence supports a finding that DG customers are not paying their full fixed costs[84] and are thus being cross-subsidized by the other residential customers,[85] there is not sufficient evidence for the Commission to determine whether that cross-subsidization results in an unduly preferential rate because not all of the utilities provided analysis regarding the extent to which cross-subsidization exists.[86] The record suggests that information would only be available after the utilities completed a class cost of service study in their next rate case.

37. The Commission finds approving the S&A is in the public interest because it allows the parties to further develop the necessary facts on a utility by utility basis. Likewise, the Commission believes this course of action allows utilities to propose new DG tariffs consistent with terms of the S&A and for the Commission to address each proposal individually. The Commission finds the S&A allows the Commission to do so without negatively impacting any of the parties. The rights and obligations of the parties are the same following this order as they were at the beginning of this docket. Therefore, the Commission finds no party is negatively impacted by the S&A because it merely shifts the discussion and production of evidence into utility specific dockets, where the burden of proof remains on the utilities to show that their proposed rate design results in non-discriminatory and just and reasonable rates. Therefore, the Commission finds the S&A is in the public interest.

[84] Initial Comments Staff, p. 1.
[85] Initial Comments Staff, pp. 1, 4; Tr. Vol. 1, p. 112.
[86] Tr. Vol. 1 pp. 113-120; p.130; pp. 298-299.

THEREFORE, THE COMMISSION ORDERS:

A. The Non-Unanimous Stipulation and Agreement is approved.

B. The parties have 15 days from the date this Order was electronically served to petition for reconsideration.[87]

C. The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Apple, Chairman; Albrecht, Commissioner; Emler, Commissioner

Dated: SEP 21 2017

Lynn M. Retz

Lynn M. Retz
Secretary to the Commission

SF

EMAILED

SEP 21 2017

[87] K.S.A. 66-118b; K.S.A. 77-529(a)(1).

CERTIFICATE OF SERVICE

16-GIME-403-GIE

I, the undersigned, certify that the true copy of the attached Order has been served to the following parties by means of Electronic Service on SEP 2 1 2017.

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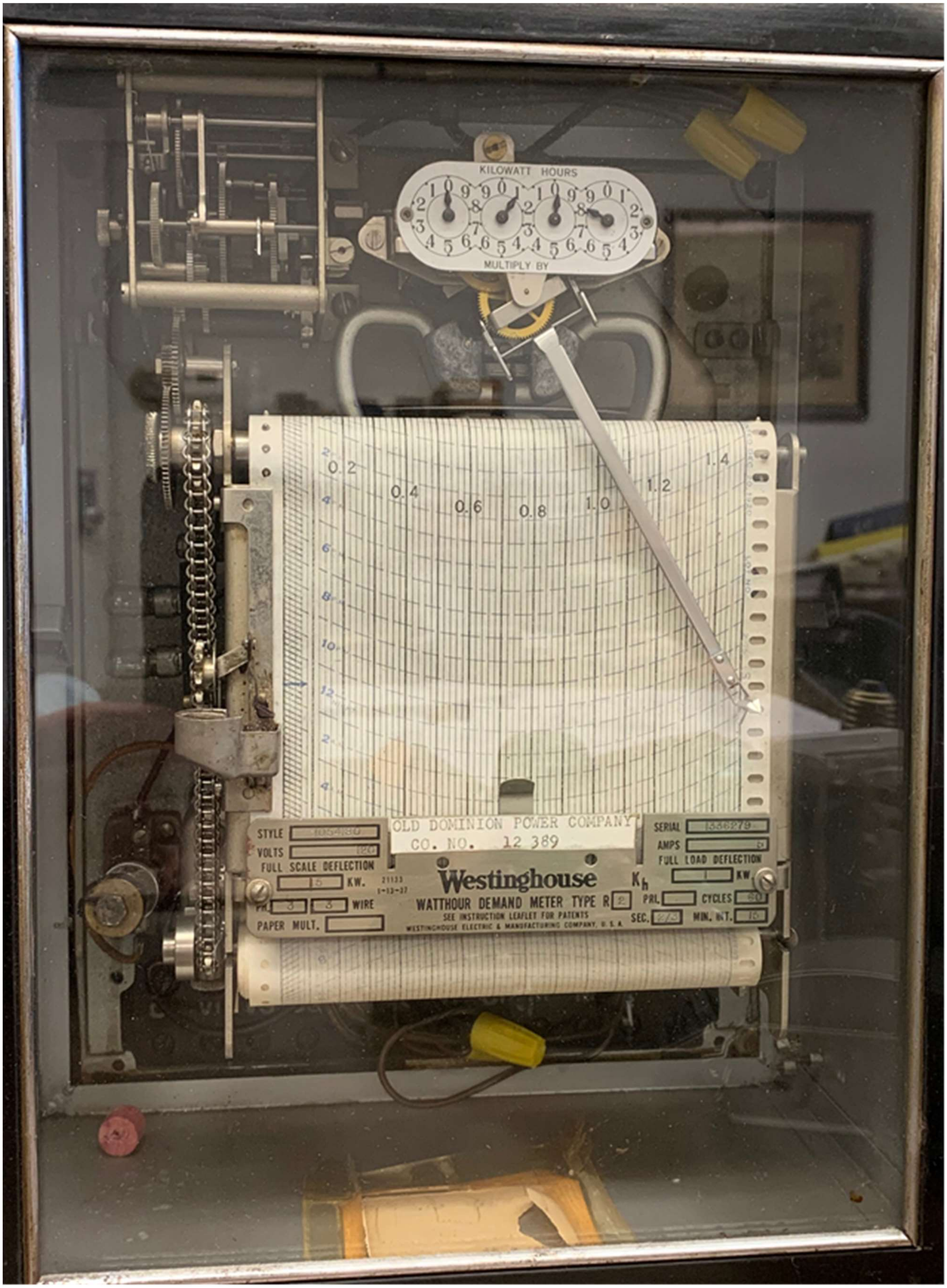
/S/ DeeAnn Shupe
DeeAnn Shupe

MAILED

SEP 21 2017

Exhibit WSS-8

Traditional Metering Equipment Required for Four-Part Rates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OLD DOMINION POWER COMPANY
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VOLTS
FULL SCALE DEFLECTION
KW.
WIRE
PAPER MULT.
Westinghouse
WATTHOUR DEMAND METER TYPE R
SEE INSTRUCTION LEAFLET FOR PATENTS
WESTINGHOUSE ELECTRIC & MANUFACTURING COMPANY, U. S. A.
SERIAL
AMPS
FULL LOAD DEFLECTION
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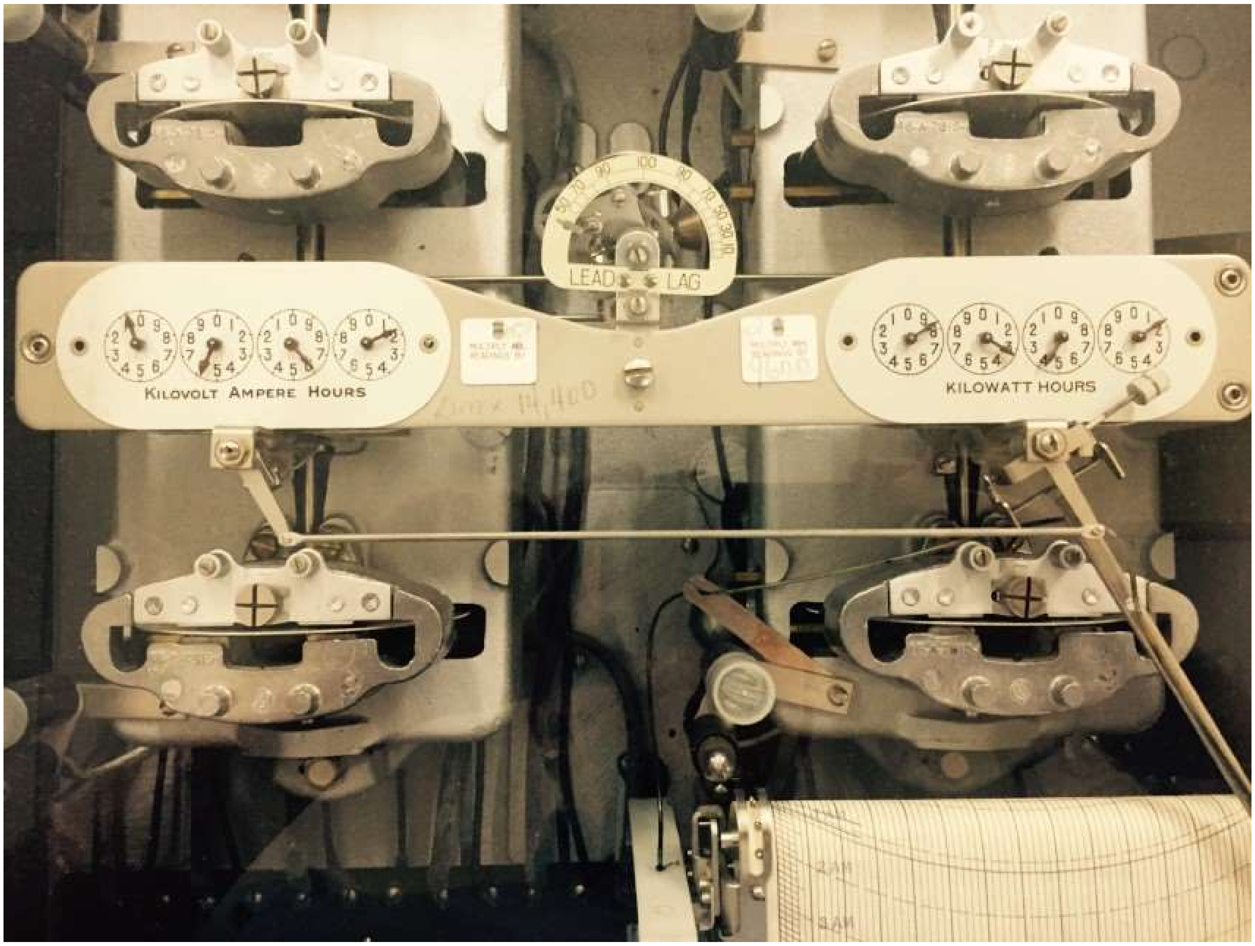
CYCLES
SEC.
MIN. INT.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LAG
KILOVOLT AMPERE HOURS
KILOWATT HOURS

INSTRUCTIONS

9-73

DEMAND METERS

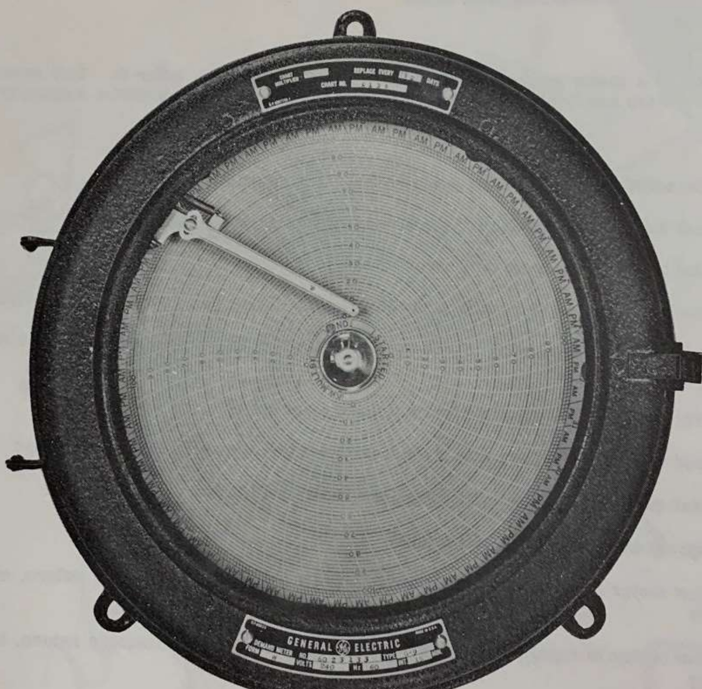
TYPES G-9, GS-9, AND GS-12

New 9-73

GENERAL ELECTRIC

RENEWAL PARTS

TYPES G-9, GS-9 AND GS-12 DEMAND METERS



When ordering renewal parts, give quantity, catalog number, description of each item required, and complete nameplate reading.

GENERAL ELECTRIC

Exhibit WSS-9

Electric Vehicle Ownership by State in U.S.

Electric Vehicle Registrations in 2018				
State	**EV Registriations**	**Population**	**Per Capita Registrations**	**Registrations per 100,000 Residents**
California	256,800	39,557,045	0.0065	649.19
Hawaii	6,590	1,420,491	0.0046	463.92
Washington	28,400	7,535,591	0.0038	376.88
Oregon	12,400	4,190,713	0.0030	295.89
Arizona	15,000	7,171,646	0.0021	209.16
Colorado	11,700	5,695,564	0.0021	205.42
Vermont	1,060	626,299	0.0017	169.25
Utah	5,220	3,161,105	0.0017	165.13
Nevada	4,810	3,034,392	0.0016	158.52
Georgia	15,300	10,519,475	0.0015	145.44
Massachusetts	9,760	6,902,149	0.0014	141.41
District Of Columb	970	702,455	0.0014	138.09
New Jersey	12,100	8,908,520	0.0014	135.83
Maryland	8,080	6,042,718	0.0013	133.71
Connecticut	4,450	3,572,665	0.0012	124.56
Florida	25,200	21,299,325	0.0012	118.31
Virginia	8,370	8,517,685	0.0010	98.27
Illinois	12,400	12,741,080	0.0010	97.32
New York	16,600	19,542,209	0.0008	84.94
Minnesota	4,740	5,611,179	0.0008	84.47
Oklahoma	3,290	3,943,079	0.0008	83.44
New Hampshire	1,120	1,356,458	0.0008	82.57
Texas	22,600	28,701,845	0.0008	78.74
Delaware	720	967,171	0.0007	74.44
Alaska	530	737,438	0.0007	71.87
North Carolina	7,320	10,383,620	0.0007	70.50
Wisconsin	3,680	5,813,568	0.0006	63.30
Pennsylvania	7,990	12,807,060	0.0006	62.39
Idaho	1,080	1,754,208	0.0006	61.57
New Mexico	1,260	2,095,428	0.0006	60.13
Tennessee	3,980	6,770,010	0.0006	58.79
Rhode Island	600	1,057,315	0.0006	56.75
Missouri	3,450	6,126,452	0.0006	56.31
Maine	750	1,338,404	0.0006	56.04
Ohio	6,510	11,689,442	0.0006	55.69
Kansas	1,610	2,911,505	0.0006	55.30
Montana	500	1,062,305	0.0005	47.07
Indiana	3,030	6,691,878	0.0005	45.28
Nebraska	850	1,929,268	0.0004	44.06
Michigan	4,210	9,995,915	0.0004	42.12
South Carolina	1,950	5,084,127	0.0004	38.35
Iowa	1,090	3,156,145	0.0003	34.54
Alabama	1,450	4,887,871	0.0003	29.67
South Dakota	260	882,235	0.0003	29.47
Wyoming	170	577,737	0.0003	29.43
Kentucky	1,240	4,468,402	0.0003	27.75
Louisiana	1,110	4,659,978	0.0002	23.82
North Dakota	170	760,077	0.0002	22.37
Arkansas	520	3,013,825	0.0002	17.25
Mississippi	390	2,986,530	0.0001	13.06
West Virginia	230	1,805,832	0.0001	12.74

Sources: Electric Vehicle Registrations were obtained from a US Department of Energy
https://afdc.energy.gov/data/10962
2018 Population
https://www.census.gov/newsroom/press-kits/2018/pop-estimates-national-state.html

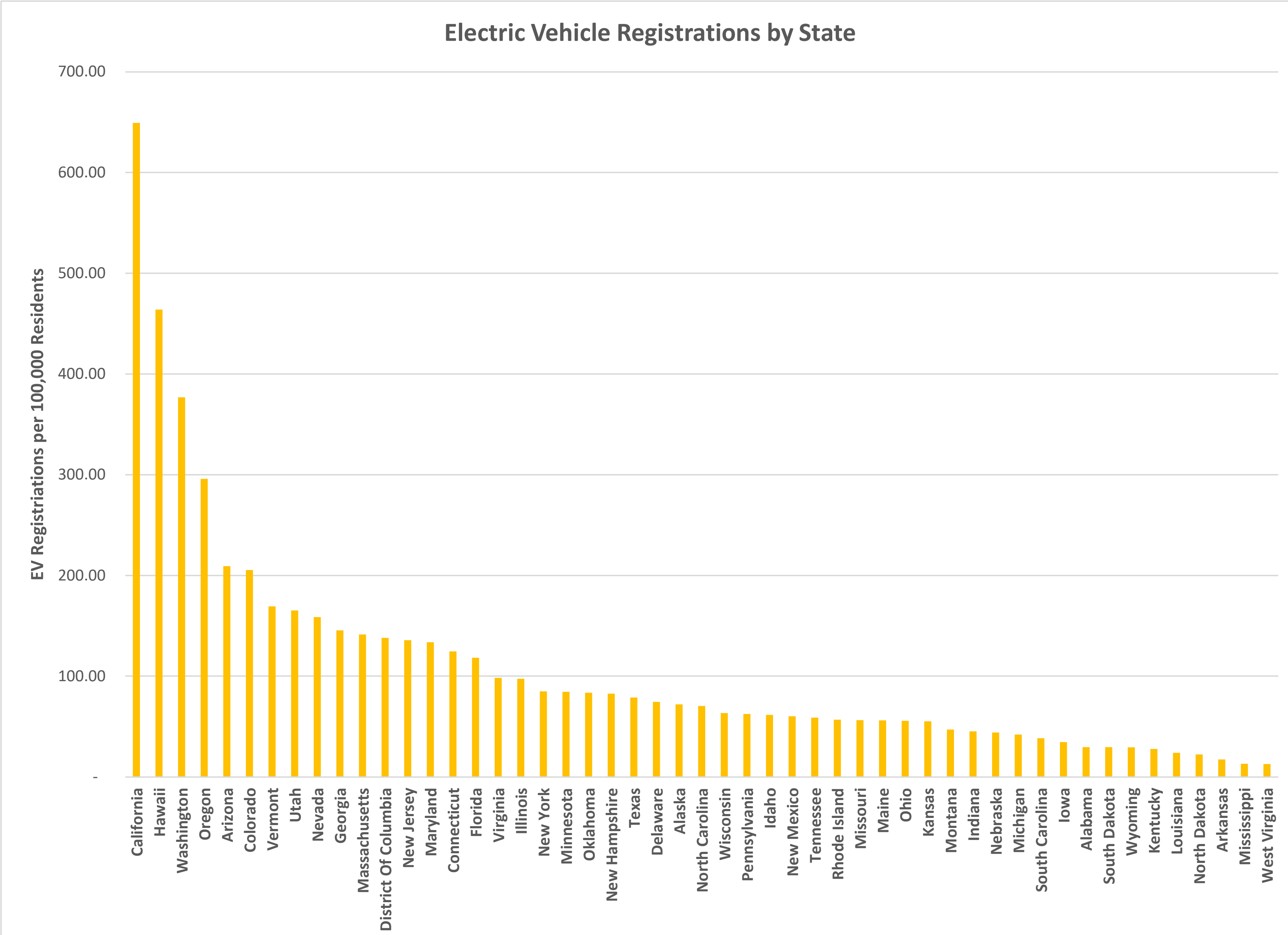

Electric Vehicle Registrations by State
EV Registriations per 100,000 Residents
700.00
600.00
500.00
400.00
300.00
200.00
100.00
-
California
Hawaii
Washington
Oregon
Arizona
Colorado
Vermont
Utah
Nevada
Georgia
Massachusetts
District Of Columbia
New Jersey
Maryland
Connecticut
Florida
Virginia
Illinois
New York
Minnesota
Oklahoma
New Hampshire
Texas
Delaware
Alaska
North Carolina
Wisconsin
Pennsylvania
Idaho
New Mexico
Tennessee
Rhode Island
Missouri
Maine
Ohio
Kansas
Montana
Indiana
Nebraska
Michigan
South Carolina
Iowa
Alabama
South Dakota
Wyoming
Kentucky
Louisiana
North Dakota
Arkansas
Mississippi
West Virginia

Exhibit WSS-10

DC Fast Charging Ports
Versus
Electric Vehicles by State in U.S.

Relationship Between Electric Vehicles and DC Fast Charging Stations

State	**DC Fast Charging Ports**	**Plug-in Electric Vehicles**
Alabama	78	1,450
Alaska	4	530
Arizona	363	15,000
Arkansas	44	520
California	4,679	256,800
Colorado	339	11,700
Connecticut	223	4,450
Delaware	65	720
District of Columbia	20	970
Florida	760	25,200
Georgia	420	15,300
Hawaii	90	6,590
Idaho	75	1,080
Illinois	337	12,400
Indiana	171	3,030
Iowa	134	1,090
Kansas	121	1,610
Kentucky	68	1,240
Louisiana	68	1,110
Maine	126	750
Maryland	424	8,080
Massachusetts	329	9,760
Michigan	280	4,210
Minnesota	187	4,740
Mississippi	56	390
Missouri	196	3,450
Montana	96	500
Nebraska	64	850
Nevada	266	4,810
New Hampshire	69	1,120
New Jersey	407	12,100
New Mexico	108	1,260
New York	579	16,600
North Carolina	297	7,320
North Dakota	34	170
Ohio	350	6,510
Oklahoma	328	3,290
Oregon	361	12,400
Pennsylvania	289	7,990
Rhode Island	38	600
South Carolina	100	1,950
South Dakota	54	260
Tennessee	171	3,980
Texas	693	22,600
Utah	186	5,220
Vermont	54	1,060
Virginia	457	8,370
Washington	566	28,400
West Virginia	60	230
Wisconsin	144	3,680
Wyoming	75	170
Total	**15,503**	**543,610**
Correlation Coefficient		**0.9867**

Source: US Department of Energy, "Alternative Fueling Station Counts by State", August 31, 2020

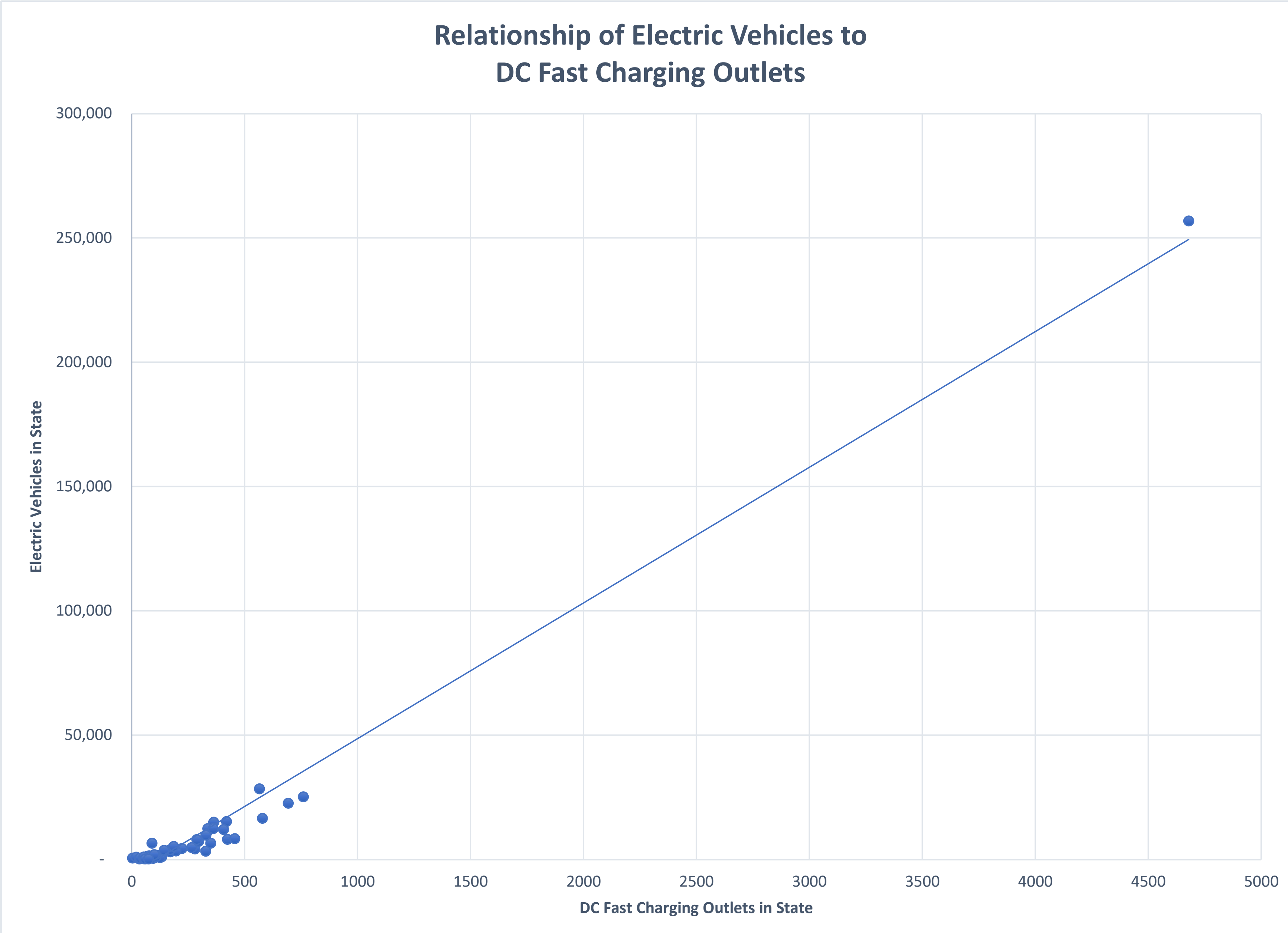


Exhibit WSS-10
Page 2 of 2

Exhibit WSS-11

Cost Support for Electric Vehicle Supply Equipment Rate and Rider

Kentucky Utilities Company
Derivation of Rates

			Clipper Creek - Single
Estimated Investment per Unit		$	800.85
Fixed Charges @	20.51%	$	244.30
O&M (Scheduled/Trouble)		$	126.00
Chargepoint Annual Cost		$	-
		$	370.30
Monthly Rate for Equipment Only		$	30.86
EVC Rate per Hour for Equipment Only			-
Distribution Energy per kWh per year (Calculated with GS Rate)	$ 0.12469	$	623.99
Distribution Energy per kWh per month		$	52.00
Distribution Energy per kWh per hour			-
Basic Service Charge		$	-
Fuel Adjustment Clause		$	-
Solar PPA Adjustment Clause		$	-
Economic Recovery Surcredit		$	-
Environmental Surcharge (Level 2)		$	-
Franchise Fee		$	-
School Tax		$	-
State Sales Tax		$	-
EVSE Monthly Rate for Equipment, Energy & Factors		**$**	**82.86**
EVC Fee per Hour for Equipment, Energy & Factors			
EVSE-R Monthly Rate for Equipment Only		**$**	**30.86**

EVSE - Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own, and install all duct systems and associated equipment. Customer shall be responsible for the charging equipment installation costs.

EVSE-R - Customer installs and owns facilities on its side of the meter to serve Company-provided charging station.

Louisville Gas and Electric Company
Derivation of Rates

		Clipper Creek - Single
Estimated Investment per Unit		$ 800.85
Fixed Charges @	20.70%	$ 245.89
O&M (Scheduled/Trouble)		$ 126.00
Chargepoint Annual Cost		$ -
		$ 371.89
Monthly Rate for Equipment Only		$ 30.99
EVC Rate per Hour for Equipment Only		-
Distribution Energy per kWh per year (Calculated with GS Rate)	$ 0.12355	$ 618.29
Distribution Energy per kWh per month		$ 51.52
Distribution Energy per kWh per hour		-
Basic Service Charge		$ -
Fuel Adjustment Clause		$ -
Solar PPA Adjustment Clause		$ -
Economic Recovery Surcredit		$ -
Environmental Surcharge (Level 2)		$ -
Franchise Fee		$ -
School Tax		$ -
State Sales Tax		$ -
EVSE Monthly Rate for Equipment, Energy & Factors		**$ 82.51**
EVC Fee per Hour for Equipment, Energy & Factors		
EVSE-R Monthly Rate for Equipment Only		**$ 30.99**

EVSE - Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own, and install all duct systems and associated equipment. Customer shall be responsible for the charging equipment installation costs.

EVSE-R - Customer installs and owns facilities on its side of the meter to serve Company-provided charging station.

Exhibit WSS-12

Cost Support for Redundant Capacity Charge

Kentucky Utilities Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2022

Secondary Service

Distribution Demand Costs				
PSS	$	4,721,893		
TODS	$	4,144,728		
Total Cost	$	8,866,621		
Billing Demand				
PSS		5,272,876		
TODS		6,217,430		
Total Cost		11,490,306		
Unit Cost			$	0.77
Rate Base				
PSS	$	49,645,807		
TODS	$	43,613,366		
Total Cost	$	93,259,173		
Return	$	6,770,616		
Unit Return			$	0.59
Capacity Charge			$	1.36 / KW

Kentucky Utilities Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2022

Primary Service

Distribution Demand Costs				
PSP	$	172,706		
TODP	$	5,548,170		
Total Cost	$	5,720,876		
Billing Demand				
PSP		301,512		
TODP		10,620,000		
Total Cost		10,921,512		
Unit Cost			$	0.52
Rate Base				
PSP	$	1,711,384		
TODP	$	57,382,076		
Total Cost	$	59,093,460		
Return	$	4,290,185		
Unit Return			$	0.39
Capacity Charge			$	0.92 / KW

Louisville Gas and Electric Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2022

Secondary Service

Distribution Demand Costs				
	PSS	$ 5,691,826		
	TODS	4,551,553		
	Total Cost	$ 10,243,379		
Billing Demand				
	PSS	4,277,098		
	TODS	4,406,484		
	Total Cost	8,683,582		
Unit Cost			$ 1.18	
Rate Base				
	PSS	$ 50,667,367		
	TODS	40,506,142		
	Total Cost	$ 91,173,509		
Return		$ 6,546,258		
Unit Return			$ 0.75	
Capacity Charge			$ 1.93	/ KW

Louisville Gas and Electric Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2022

Primary Service

Distribution Demand Costs					
	PSP	$ 304,138			
	TODP	4,297,652			
	Total Cost	$ 4,601,791			
Billing Demand					
	PSP	340,066			
	TODP	5,354,606			
	Total Cost	5,694,672			
Unit Cost			$	0.81	
Rate Base					
	PSP	$ 2,580,628			
	TODP	36,684,134			
	Total Cost	$ 39,264,762			
Return		$ 2,819,210			
Unit Return			$	0.50	
Capacity Charge			$	1.31	/ KW

Exhibit WSS-13

Summary of Class Rates of Returns for Gas Operations

Louisville Gas and Electric Company

Summary of Adjusted Rates of Return by Class

Rate Class	Revenue	Operating Expenses	Operating Margin	Rate Base	Rate of Return On Rate Base	Rate of Return On Rate Base After Increase
Residential Service Rate RGS	$ 160,544,346	$ 126,307,888	$ 34,236,458	$ 741,469,107	4.62%	6.87%
Commercial Service Rate CGS	60,474,931	42,069,078	18,405,853	243,310,119	7.56%	9.08%
Industrial Service Rate IGS	4,718,125	2,739,722	1,978,403	14,445,380	13.70%	13.69%
As Available Gas Service Rate AAGS	224,602	287,484	(62,883)	1,942,049	-3.24%	0.98%
Firm Transportation Service Rate FT	6,589,010	7,483,056	(894,046)	51,183,321	-1.75%	2.10%
	$ 232,551,013	$ 178,887,228	$ 53,663,785	$ 1,052,349,977	5.10%	7.23%

Exhibit WSS-14

Analysis of Subsidy Reduction for Gas Operations

Louisville Gas and Electric Company
25% Subsidy Reduction for Gas Operations

		25% Subsidy Reduction RGS, AAGS, FT					
		Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Test Year Operating Income		$ 53,663,785	$ 34,236,458	$ 18,405,853	$ 1,978,403	$ (62,883)	$ (894,046)
Proposed Increase		$ 29,977,693	$ 22,317,229	$ 4,920,979	$ -	$ 109,476	$ 2,630,008
Adjustment to Forefeited Discounts							
Adjustment to Returned Check Fees							
Incremental Income Taxes	24.85%	$ 7,449,292	$ 5,545,709	$ 1,222,836	$ -	$ 27,204	$ 653,543
Incremental Uncollectable Accounts Expense	0.203%	$ 60,855	$ 45,304	$ 9,990	$ -	$ 222	$ 5,339
Incremental Commission Fees	0.20%	$ 59,955	$ 44,634	$ 9,842	$ -	$ 219	$ 5,260
	25.25%						
Net Operating Income Adjusted for Increase		$ 76,071,376	$ 50,918,040	$ 22,084,164	$ 1,978,403	$ 18,948	$ 1,071,821
Net Cost Rate Base (Same as Above)		$ 1,052,349,977	$ 741,469,107	$ 243,310,119	$ 14,445,380	$ 1,942,049	$ 51,183,321
Rate of Return -- Proposed		**7.23%**	**6.87%**	**9.08%**	**13.70%**	**0.98%**	**2.09%**
Equalized ROR		$ 76,071,376	$ 53,598,685	$ 17,588,194	$ 1,044,215	$ 140,385	$ 3,699,896
Proposed Subsidy Reduction in Revenue		$ -	$ (2,680,645)	$ 4,495,970	$ 934,187	$ (121,437)	$ (2,628,075)

Exhibit WSS-15

Cost Components for

Residential Gas Service Rate RGS

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2022

Rate RGS

	Customer Costs								Transmission and	
Description	Customer-Related Low Pressure Mains Costs	Customer-Related High Pressure Main Costs	Customer-Related Direct Costs	Total Customer-Related Costs	Storage/Transmission Demand-Related Costs	Storage Compressor Costs	Other Procurement Costs	Demand Related Low Pressure Mains Costs	Demand Related High Pressure Mains Costs	Total Costs
(1) Rate Base	$ 172,050,186	$ 13,098,613	$ 240,278,815	$ 425,427,614	$ 138,972,330	$ 1,711,821	$ 498,480	$ 44,788,728	$ 130,070,134	$ 741,469,107
(2) Rate Base Adjustments	-	-	-	-	-	-	-	-	-	-
(3) Rate Base as Adjusted [(1) + (2)]	$ 172,050,186	$ 13,098,613	$ 240,278,815	$ 425,427,614	$ 138,972,330	$ 1,711,821	$ 498,480	$ 44,788,728	$ 130,070,134	$ 741,469,107
(4) Rate of Return	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
(5) Return [(3) x (4)]	$ 11,816,427	$ 899,614	$ 16,502,377	$ 29,218,418	$ 9,544,636	$ 117,568	$ 34,236	$ 3,076,095	$ 8,933,232	$ 50,924,184
(6) Interest Expenses	$ 3,318,295	$ 236,757	$ 4,455,708	$ 8,010,760	$ 1,911,258	$ -	$ -	$ 1,042,152	$ 1,771,296	$ 12,735,466
(7) Net Income [(5) - (6)]	$ 8,498,131	$ 662,858	$ 12,046,669	$ 21,207,658	$ 7,633,378	$ 117,568	$ 34,236	$ 2,033,943	$ 7,161,936	$ 38,188,718
(8) Income Taxes	$ 2,460,048	$ 191,885	$ 3,487,282	$ 6,139,215	$ 2,209,718	$ 34,034	$ 9,911	$ 588,788	$ 2,073,245	$ 11,054,910
(9) Operation and Maintenance Expenses	$ 16,176,129	$ 1,154,148	$ 27,229,324	$ 44,559,601	$ 5,599,363	$ 6,261,343	$ 1,823,293	$ 5,080,317	$ 13,078,613	$ 76,402,530
(10) Depreciation Expenses	6,674,526	476,220	15,912,498	23,063,244	4,780,881	-	-	2,096,219	4,046,968	33,987,312
(11) Other Taxes	2,712,724	193,550	3,642,564	6,548,838	1,562,463	-	-	851,965	1,448,044	10,411,309
(12) Other Expenses	(110)	(8)	(152)	(270)	(60)	-	-	(34)	(57)	(421)
(13) Expense Adjustments (Non-Income Tax)	19,049	1,359	32,065	52,473	6,594	7,373	2,147	5,983	15,401	89,972
(14) Total Cost of Service [(4)+(8)+(9)+(10)+(11)+(12)+(13)]	$ 39,858,793	$ 2,916,768	$ 66,805,958	$ 109,581,519	$ 23,703,594	$ 6,420,318	$ 1,869,587	$ 11,699,332	$ 29,595,445	$ 182,869,795
(15) Less: Misc Revenue	541,408	39,619	907,436	1,488,463	321,970	87,208	25,395	158,914	402,000	$ 2,483,950
(16) Net Cost of Service [(13) - (14)]	$ 39,317,385	$ 2,877,149	$ 65,898,522	$ 108,093,056	$ 23,381,624	$ 6,333,110	$ 1,844,192	$ 11,540,418	$ 29,193,446	$ 180,385,845
(17) Billing Units	110,180,767	110,180,767	110,180,767	110,180,767	7,724,367	19,501,502	19,501,502	322,467	322,467	
(18) Unit Costs [(15) / (16)]	$0.36/Cust/Day	$0.03/Cust/Day	$0.60/Cust/Day	$0.98/Cust/Day	$3.0270/Mcf	$0.3247/Mcf	$0.0946/Mcf	$35.7879/Mcf	$90.5317/Mcf	

Exhibit WSS-16

Cost Support for Pole Attachment Charge

Kentucky Utilities Company and Louisvillle Gas & Electric Company
Cost Support for Attachment Charges for Wireline Pole Attachments
Based on 12 Months Ended June 30, 2022

Pole Description		**35'**	**40'**	**45'**	**Total**
Gross Plant		$ 42,672,814	$ 159,603,939	$ 145,470,993	$ 347,747,746
Remove Appurtenances		15%	15%	15%	
Gross Plant less Appurtenances		$ 36,271,892	$ 135,663,348	$ 123,650,344	$ 295,585,584
Accumulated Depreciation		(15,423,131)	(57,685,262)	(52,577,225)	(125,685,618)
Remove Appurtenances		15%	15%	15%	
Accumulated Depreciation less Appurtenances		$ (13,109,661)	$ (49,032,472)	$ (44,690,642)	$ (106,832,775)
Net Plant		$ 23,162,231	$ 86,630,876	$ 78,959,702	$ 188,752,809
Accumulated Deferred Income Taxes		$ (5,716,450)	$ (21,380,544)	$ (19,487,294)	$ (46,584,288)
Cash Working Capital		269,597	1,008,340	919,052	2,196,989
Common Plant		773,795	2,894,131	2,637,856	6,305,782
Net Cost Rate Base		$ 18,489,172	$ 69,152,804	$ 63,029,316	$ 150,671,292
Rate of Return		7.16%	7.16%	7.16%	
Return		$ 1,324,579	$ 4,954,161	$ 4,515,469	$ 10,794,208
Income Taxes	24.95%	$ 326,632	$ 1,221,662	$ 1,113,484	$ 2,661,779
Property Taxes		$ 398,917	$ 1,492,021	$ 1,359,902	$ 3,250,839
Depreciation Expenses		$ 714,291	$ 2,671,575	$ 2,435,007	$ 5,820,873
Maintenance of Poles		$ 473,838	$ 1,772,238	$ 1,615,306	$ 3,861,382
Tree Trimming of Poles		1,503,856	5,624,689	5,126,622	$ 12,255,167
A&G Expense Allocation to Poles		240,950	901,195	821,394	$ 1,963,538
Revenue Requirement		$ 4,983,062	$ 18,637,541	$ 16,987,185	$ 40,607,787
Quantity		104,622	195,898	92,631	393,151
Average Installed Cost		$ 47.63	$ 95.14	$ 183.39	$ 103.29
(1) Amount of Usable Space Occupied (in feet)		1.00	1.00	1.00	1.00
(2) Total Usable Space (per Order 251)		13.17	13.17	13.17	13.17
Space Usage Factor ((1) / (2))		0.0759	0.0759	0.0759	0.0759
Pole Attachment Rate		$ 3.62	$ 7.22	$ 13.92	**$ 7.84**

Exhibit WSS-17

Cost Support for Excess Facilities Rider

Kentucky Utilities
Excess Facilities Charges

		Assuming Customer Does Not Make Contribution In Aid of Construction	Assuming Customer Makes Contribution In Aid of Construction
1	Present Value of Replacement Plant as a Percentage of Original Cost	21.77	21.77
2	Original Cost Value	100	-
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost	121.77	21.77
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)	0.00702	0.00702
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)	0.86%	0.15%
6	O&M Percentage	0.32%	0.32%
7	Total Excess Facilities Charge	1.17%	0.47%

Louisville Gas and Electric Company
Excess Facilities Charges
Electric Service

		Assuming Customer Does Not Make Contribution In Aid of Construction	Assuming Customer Makes Contribution In Aid of Construction
1	Present Value of Replacement Plant as a Percentage of Original Cost	21.77	21.77
2	Original Cost Value	100	-
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost	121.77	21.77
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)	0.00702	0.00702
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)	0.86%	0.15%
6	O&M Percentage	0.37%	0.37%
7	Total Excess Facilities Charge	1.23%	0.52%

Louisville Gas and Electric Company

Excess Facilities Charges
Gas Service

		Assuming Customer Does Not Make Contribution In Aid of Construction	Assuming Customer Makes Contribution In Aid of Construction
1	Present Value of Replacement Plant as a Percentage of Original Cost	21.77	21.77
2	Original Cost Value	100	-
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost	121.77	21.77
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)	0.00699	0.00699
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)	0.85%	0.15%
6	O&M Percentage	0.30%	0.30%
7	Total Excess Facilities Charge	1.15%	0.45%

Exhibit WSS-18

Change in Other Operating Revenues For Excess Facilities Rider

Kentucky Utilities Company/Louisville Gas and Electric Company
Excess Facilities Proposed Rate Change and Revenue Impact
Case Nos. 2020-00349 and 2020-00350

	Installed Cost of Excess Facilities	Current Rate	Forecasted Test Year Revenue at Current Rate	Proposed Rate	Forecasted Test Year Revenue at Proposed Rate	Revenue Increase (Decrease)
Kentucky Utilities Company						
Excess Facilities Percentage With No Contribution-in-Aid-of-Construction	$ 9,865,917.88	1.16%	$ 1,373,335.77	1.17%	$ 1,385,174.87	$ 11,839
Excess Facilities Percentage With Contribution-in-Aid-of-Construction	$ 914,769.37	0.47%	$ 51,592.99	0.47%	$ 51,592.99	$ (0)
Total -- KU						$ 11,839
Louisville Gas and Electric Company						
Excess Facilities Percentage With No Contribution-in-Aid-of-Construction	$ 4,982,340.73	1.22%	$ 729,414.68	1.21%	$ 723,435.87	$ (5,979)
Excess Facilities Percentage With Contribution-in-Aid-of-Construction	$ 1,218,457.13	0.52%	$ 76,031.72	0.52%	$ 76,031.72	$ (0)
Total -- LG&E						$ (5,979)

Note: No gas customers are currently taking service under the Excess Facilities Rider and none are projected for the forecasted test year.

Exhibit WSS-19

Cost Support for Miscellaneous Charges

Summary of Increases (Decreases) to Special Charges
Based on the 12 Months Ended July 31, 2020

Miscellaneous Charge	Current Charge	Actual Cost	Proposed Charge
LG&E - Electric			
Disconnect/Reconnect Charge	$ 28.00	$ 32.22	$ 32.00
Returned Check Fee	$ 3.00	$ 3.70	$ 3.70
Meter-Test Charge	$ 75.00	$ 78.85	$ 79.00
Meter Pulse Relaying	$ 24.00	$ 20.76	$ 21.00
UAR without meter replacement	$ 70.00	$ 49.13	$ 49.00
UAR Charge for 1/0 Standard Meter Replacement	$ 90.00	$ 70.16	$ 70.00
UAR Charge for 1/0 AMR Meter Replacement	$ 110.00	$ 90.97	$ 91.00
UAR Charge for 1/0 AMS Meter Replacement	$ 174.00	$ 153.39	$ 153.00
UAR Charge for 3/0 Standard Meter Replacement	$ 177.00	$ 158.60	$ 159.00
AMI Opt-Out Charge -- One-Time Charge		$ 34.66	$ 35.00
AMI Opt-Out Charge -- Monthly Charge		$ 12.38	$ 12.00
LG&E - Gas			
Disconnect/Reconnect Charge	$ 28.00	$ 32.22	$ 32.00
Returned Check Fee	$ 3.00	$ 3.70	$ 3.70
Meter-Test Charge	$ 90.00	$ 101.26	$ 101.00
Inspection Charge	$ 150.00	$ 155.23	$ 155.00
Meter Pulse Relaying Non-FT Non-TS2	$ 24.34	$ 27.52	$ 28.00
Meter Pulse Relaying - FT/TS2	$ 7.17	$ 8.19	$ 8.00
Additional Trip Charge	$ 150.00	$ 155.23	$ 155.00
UAR without meter replacement	$ 70.00	$ 49.13	$ 49.00
UAR with meter replacement	$ 132.00	$ 113.86	$ 114.00
AMI Opt-Out Charge -- One-Time Charge		$ 32.63	$ 33.00
AMI Opt-Out Charge -- Monthly Charge		$ 5.17	$ 5.00
KU			
Disconnect/Reconnect Charge	$ 28.00	$ 37.23	$ 37.00
Returned Check Fee	$ 3.00	$ 3.48	$ 3.50
Meter-Test Charge	$ 75.00	$ 79.49	$ 79.00
Meter Pulse Relaying	$ 24.00	$ 20.87	$ 21.00
UAR without meter replacement	$ 70.00	$ 44.68	$ 45.00
UAR Charge for 1/0 Standard Meter Replacement	$ 90.00	$ 65.72	$ 66.00
UAR Charge for 1/0 AMR Meter Replacement	$ 110.00	$ 86.52	$ 87.00
UAR Charge for 1/0 AMS Meter Replacement	$ 174.00	$ 148.95	$ 149.00
UAR Charge for 3/0 Standard Meter Replacement	$ 177.00	$ 154.15	$ 154.00
AMI Opt-Out Charge -- One-Time Charge		$ 38.77	$ 39.00
AMI Opt-Out Charge -- Monthly Charge		$ 14.87	$ 15.00

Kentucky Utilities Company
Disconnect/Reconnect
Cost Justification

		Cost
Disconnect Service	$	18.62
Reconnect Service		18.62
	$	37.23

Louisville Gas and Electric Company
Disconnect/Reconnect
Cost Justification

	Cost
Disconnect Service	$ 16.11
Reconnect Service	16.11
	$ 32.22

Kentucky Utilities Company
Electric Meter Test
Cost Justification

	Cost
Labor - One Hour	$ 74.16
Vehicle - 2/3 Hour	5.32
	$ 79.49

Louisville Gas and Electric Company
Electric Meter Test
Cost Justification

	Cost
Labor - One Hour	$ 73.53
Vehicle - 2/3 Hour	5.32
	$ 78.85

Louisville Gas and Electric Company
Gas Meter Test
Cost Justification

	Cost
Labor - One and one third hour	$ 56.38
Meter Test - One hour	44.88
	$ 101.26

Louisville Gas and Electric Company
Gas Inspection Charge/Additional Trip Charge
Cost Justification

	Cost
Labor	$ 146.92
Transportation	8.32
	$ 155.23

Louisville Gas and Electric Company
Returned Check/ACH
Cost Justification

LG&E Returned Check/ACH Costs				
		Returns	Cost	Average
US Bank/MUFG		15,484	$ 44,767	$ 3.01
Labor (incl. burdens)	65 hours x $31.55 (straight time labor with burdens) / total LGE/KU returns			0.06
Postage/Material	$.47 postage, plus $.09 letterhead & $.05 envelope			0.63
Total Per Item Cost at July 31, 2020				$ 3.70

Kentucky Utilities Company
Returned Check/ACH
Cost Justification

KU Returned Check/ACH Costs

	Returns		Cost	Average
US Bank/MUFG		20,041	$ 53,694	$ 2.79
Labor (incl. burdens)	65 hours x $31.55 (straight time labor with burdens) / total LGE/KU returns			0.06
Postage/Material	$.47 postage, plus $.09 letterhead & $.05 envelope			0.63
Total Per Item Cost at July 31, 2020				$ 3.48

Louisville Gas and Electric Company
Meter Pulse - ELECTRIC
Cost Justification

	Cost
Equipment Installed Costs:	
Pulse Relay	57.84
Pulse Initiator Board	157.76
Relay Enclosure	89.40
5 Hours Labor (loaded)	364.46
Vehicle 2 hours	12.92
Total Cost at July 31, 2020	682.38

Charge per pulse per meter per month (5 Year Contract including carrying costs)	$ 20.76

Louisville Gas and Electric Company
Meter Pulse - GAS
Cost Justification

	Cost
Non-FT and Non-TS-2 customer without telemetry	
Equipment Installed Costs:	
Equipment Costs	670.01
3 Hours Labor (loaded)	211.50
Vehicle	22.04
Total Cost at July 31, 2020	903.55
Charge per pulse per meter per month (5 Year Contract including carrying costs	$ 27.52
FT and TS-2 customer with telemetry	
AMI Opt-Out Charge -- One-Time Charge	
AMI Opt-Out Charge -- Monthly Charge	
Equipment Installed Costs:	
Equipment Costs	-
3 Hours Labor (loaded)	241.40
Vehicle	27.54
Total Cost at April 30, 2018	268.94
Charge per pulse per meter per month (5 Year Contract including carrying costs)	$ 8.19

Kentucky Utilities Company
Meter Pulse
Cost Justification

	Cost
Equipment Installed Costs:	
Pulse Relay	57.85
Pulse Initiator Board	157.77
Relay Enclosure	89.40
5 Hours Labor (loaded)	367.64
Vehicle 2 hours	15.83
Total Cost at July 31, 2020	688.49

Charge per pulse per meter per month (5 Year Contract including carrying costs)	$ 20.87

Louisville Gas and Electric Company
Electric Unauthorized Meter Reconnect Charge
Cost Justification

	Cost
Field Services - (1/4 hour)	$ 15.57
Transportation - (1/4 hour)	$ 1.57
Back Office Admin Labor - (1/2 hour)	$ 20.37
Lock Costs	$ 11.62
Total Charge without meter replacement at July 31, 2020	$ 49.13

Total Charge if meter replacement necessary:	
UAR Charge for 1/0 Standard Meter Replacement	
Charge without meter replacement	$ 49.07
Charge for 1/0 Standard Meter Replacement	$ 21.09
	$ 70.16
UAR Charge for 1/0 AMR Meter Replacement	
Charge without meter replacement	$ 48.92
Charge for 1/0 AMR Meter Replacement	$ 42.06
	$ 90.97
UAR Charge for 1/0 AMS Meter Replacement	
Charge without meter replacement	$ 48.71
UAR Charge for 3/0 Standard Meter Replacement	
Charge without meter replacement	$ 48.70
Charge for 3/0 Standard Meter Replacement	$ 109.90
	$ 158.60

Labor and transportation costs to inspect and lock service, perform back office requirements and meter replacement if necessary.

Louisville Gas and Electric Company
Gas Unauthorized Meter Reconnect Charge
Cost Justification

	Cost
Field Services - (1/4 hour)	$ 15.57
Transportation - (1/4 hour)	$ 1.57
Back Office Admin Labor - (1/2 hour)	$ 20.37
Lock Costs	$ 11.62
Total Charge without meter replacement at July 31, 2020	$ 49.13

Total Charge if meter replacement necessary:	
UAR Charge for Standard Meter Replacement	
Charge without meter replacement	$ 48.81
Charge for Standard Meter Replacement	$ 65.05
	$ 113.86

Labor and transportation costs to inspect and lock service, perform back office requirements and meter replacement if necessary.

Kentucky Utilities Company
Electric Unauthorized Meter Reconnect Charge
Cost Justification

	Cost
Field Services - (1/4 hour)	$ 11.14
Transportation - (1/4 hour)	$ 1.57
Back Office Admin Labor - (1/2 hour)	$ 20.36
Lock Costs	$ 11.61
Total Charge without meter replacement at July 31, 2020	$ 44.68

Total Charge if meter replacement necessary:	
UAR Charge for 1/0 Standard Meter Replacement	
Charge without meter replacement	$ 44.63
Charge for 1/0 Standard Meter Replacement	$ 21.09
	$ 65.72
UAR Charge for 1/0 AMR Meter Replacement	
Charge without meter replacement	$ 44.49
Charge for 1/0 AMR Meter Replacement	$ 42.04
	$ 86.52
UAR Charge for 1/0 AMS Meter Replacement	
Charge without meter replacement	$ 44.30
Charge for 1/0 AMS Meter Replacement	$ 104.65
	$ 148.95
UAR Charge for 3/0 Standard Meter Replacement	
Charge without meter replacement	$ 44.29
Charge for 3/0 Standard Meter Replacement	$ 109.86
	$ 154.15

Labor and transportation costs to inspect and lock service, perform back office requirements and meter replacement if necessary.

LG&E -- Electric AMI Opt-Out Charge

	One-Time Fee		
4.	Meter Readers	$	59,591
5.	Field Services	$	47,136
6.	Enrollment	$	12,267
7.	One-Time Fee	$	118,995
8.	One-Time Fee costs divided by All Opt-Out Contracts	$	34.66
	One-Time and Recurring Capital Costs		
	15 Year Life		
9.	Mesh Network	$	22,281
10.	Enrollment, Billing and Reporting	$	65,174
11.	One-Time and Recurring Capital Costs to be recovered	$	87,455
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$	25.47
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer[1]	$	0.43
	Annual Recurring Costs		
14.	Meter Readers	$	487,965
15.	Field Services	$	4,055
16.	Mesh Network	$	326
17.	Annual Recovery of on-going Costs	$	492,346
18.	Monthly Recovery of Recurring Costs per Contract	$	11.95
19.	Total Monthly Fee (13 + 18)	$	12.38

LG&E -- Gas AMI Opt-Out Charge

	One-Time Fee		
4.	Meter Readers	$	45,652
5.	Field Services	$	30,776
6.	Enrollment	$	9,398
7.	One-Time Fee	$	85,827
8.	One-Time Fee costs divided by All Opt-Out Contracts	$	32.63
	One-Time and Recurring Capital Costs		
	15 Year Life		
9.	Mesh Network	$	17,065
10.	Enrollment, Billing and Reporting	$	49,915
11.	One-Time and Recurring Capital Costs to be recovered	$	66,980
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$	25.47
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer[1]	$	0.43
	Annual Recurring Costs		
14.	Meter Readers	$	146,300
15.	Field Services	$	3,107
16.	Mesh Network	$	250
17.	Annual Recovery of on-going Costs	$	149,657
18.	Monthly Recovery of Recurring Costs per Contract	$	4.74
19.	Total Monthly Fee (13 + 18)	$	5.17

Kentucky Utilities -- AMI Opt Out Charges

	One-Time Fee		
4.	Meter Readers	$	74,555
5.	Field Services	$	74,938
6.	Enrollment	$	15,176
7.	One-Time Fee	$	164,670
8.	One-Time Fee costs divided by All Opt-Out Contracts	$	38.77
	One-Time and Recurring Capital Costs		
	15 Year Life		
9.	Mesh Network	$	27,561
10.	Enrollment, Billing and Reporting	$	80,618
11.	One-Time and Recurring Capital Costs to be recovered	$	108,179
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$	25.47
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer[1]	$	0.43
	Annual Recurring Costs		
14.	Meter Readers	$	722,834
15.	Field Services	$	12,907
16.	Mesh Network	$	403
17.	Annual Recovery of on-going Costs	$	736,144
18.	Monthly Recovery of Recurring Costs per Contract	$	14.44
19.	Total Monthly Fee (13 + 18)	$	14.87

Exhibit WSS-20

Change in Other Operating Revenues For Other Miscellaneous Charges

Summary of Increases (Decreases) to Miscellaneous Charges - Current vs. Proposed
Based on the 12 Months Ended July 31, 2020

Miscellaneous Charge	LG&E - Electric	LG&E - Gas	KU
Disconnect/Reconnect Charge	$ 139,956	$ 10,804	$ 384,759
Returned Check Fee*	$ 8,457	$ 2,382	$ 10,021
Meter-Test Charge	$ 76	$ -	$ 168
Meter Pulse Relaying	$ (3,525)		$ (4,122)
Meter Pulse Relaying Non-FT Non-TS2		$ 706	
Meter Pulse Relaying - FT/TS2		$ 46	
Third-Trip Inspection Charge		$ -	
Additional Trip Charge		$ -	
Unauthorized Reconnect Charge	$ (55,505)	$ (4,977)	$ (18,399)
Total	$ 89,459	$ 8,962	$ 372,426

Exhibit WSS-21

LOLP Analysis for Electric Cost of Service Study

Kentucky Utilities Company
LOLP Fixed Production Cost Allocation Factor
For the 12 Months Ended June 30, 2022

Rate Class	**Weighted LOLP**
	$\sum_{i=1}^{8760} LOLP_i * \overline{LOAD}_i$
Residential	1,011,037
General Service	272,317
All Electric Schools	17,474
TOD Secondary	244,227
TOD Primary	447,085
PS Secondary	253,947
PS Primary	11,033
RTS	145,533
Outdoor Sports Lighting	30
EV_Charge	2
Ind. Service Trans.	60,265
Unmetered Lighting	393
Traffic Energy Service	234
Lighting Energy Service	14
	2,463,591

Louisville Gas & Electric Company
LOLP Fixed Production Cost Allocation Factor
For the 12 Months Ended June 30, 2022

Rate Class	Weighted LOLP
	$\sum_{i=1}^{8784} LOLP_i * \overline{LOAD}_i$
Residential	902,573
General Service	213,017
TOD Secondary	186,383
TOD Primary	226,687
PS Secondary	238,519
PS Primary	14,423
RTS	103,765
Spec Contr #1(LWC)	5,705
Outdoor School Lighting	1
EV_Charge	3
Unmetered Lighting	317
Traffic Energy Svc	307
Lighting Energy Svc	11
Total	1,891,712

Exhibit WSS-22

Comparison of LOLP
Class Rates of Return with
12-CP and 6-CP Methodologies

Kentucky Utilities Company			
Rate Class	LOLP Current Rate of Return on Rate Base	12CP Current Rate of Return on Rate Base	6 CP Current Rate of Return on Rate Base
Residential Rate RS	2.67%	2.52%	2.14%
General Service Rate GS	11.05%	11.32%	11.21%
All Electric Schools Rate AES	5.89%	3.17%	3.68%
Power Service Rate PS	10.28%	10.07%	10.41%
Time of Day Secondary Rate TODS	3.95%	3.93%	4.68%
Time of Day Primary Rate TODP	3.20%	3.78%	4.26%
Retail Transmission Service Rate RTS	3.53%	3.54%	4.65%
Fluctuating Load Service Rate FLS	2.75%	4.98%	5.40%
Lighting Rate LS & RLS	12.32%	10.41%	10.54%
Lighting Rate LE	28.05%	9.27%	10.03%
Lighting Rate TE	12.39%	12.34%	13.18%
Outdoor Sports Lighting Rate OSL	30.32%	30.27%	30.28%
Electric Vehicle Charging Rate EV	-27.00%	-27.07%	-27.07%
Solar Share Rate SSP	-1.31%	-1.31%	-1.31%
Business Solar Rate BS	4.80%	4.80%	4.80%

Louisville Gas and Electric Company			
Rate Class	LOLP Current Rate of Return on Rate Base	12CP Current Rate of Return on Rate Base	6 CP Current Rate of Return on Rate Base
Residential Rate RS	0.60%	1.75%	1.33%
General Service Rate GS	10.96%	9.98%	9.67%
Power Service Rate PS	10.53%	8.68%	9.13%
TOD Rate TOD Primary	6.45%	5.04%	6.02%
TOD Rate TOD Secondary	5.33%	3.96%	4.44%
Retail Transmission Service Rate RTS	7.23%	3.75%	5.76%
Special Contract Customer	5.52%	2.44%	3.29%
Lighting Rate RLS & LS	9.74%	7.79%	8.02%
Lighting Rate LE	31.88%	8.24%	9.82%
Lighting Rate TE	15.01%	11.82%	13.90%
Outdoor Sports Lighting OSL	89.10%	92.28%	92.63%
Electric Vehicle Charging EVC	-27.07%	-27.08%	-27.10%
Solar Share SS	3.60%	3.60%	3.60%
Business Solar BS	-4.38%	-4.38%	-4.38%

Exhibit WSS-23

Zero Intercept Analysis
For
Overhead Conductor
(Kentucky Utilities)

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

July 31, 2020

Weighted Linear Regression Statistics

	Estimate	Standard Error	T-Statistic
Size Coefficient ($ per MCM)	0.0041724	0.0008336	5.00525
Zero Intercept ($ per Unit)	1.3801706	0.2486132	5.55148
R-Square	0.8225292		

Plant Classification

Total Number of Units	99,629,647
Zero Intercept	1.3801706
Zero Intercept Cost	$ 137,505,908
Total Cost of Sample	$ 214,874,064
Percentage of Total	0.639937206
Percentage Classified as Customer-Related	63.99%
Percentage Classified as Demand-Related	36.01%

Zero Intercept Analysis
Account 365 -- Overhead Conductor

July 31, 2020

Description	Size	Cost	Quantity	Avg Cost
#2 Triplex	66.369	15,319,819.64	9,502,231.00	1.612234
#4 Aluminum Poly	41.74	128,346.24	27,617.00	4.6473636
#2 ACSR	66.36	1,404,030.05	183,400.00	7.6555619
1/0 CONDUCTOR	105.6	4,279,000.42	692,306.00	6.1807935
1/0 Triplex	105.6	134,027.21	22,210.00	6.0345434
1/0 Aluminum	105.6	117,488.54	24,884.00	4.7214491
123,270 ACAR WIRE	123.27	17,139,725.02	9,362,717.00	1.8306358
195,700 ACAR WIRE	195.7	2,630,925.27	1,873,176.00	1.4045265
2/0 COPPER CONDUCTOR	133.1	1,346,236.36	532,633.00	2.5275121
20 M.A.W. MESSENGER WIRE	20	2,855,091.75	1,333,578.00	2.140926
336,400 19 STR. ALL ALUMINUM	336.4	9,462,230.02	5,646,839.00	1.6756685
350 MCM COPPER CONDUCTOR	350	2,293,985.20	85,617.00	26.793571
392,500 24/13 ACAR WIRE	392.5	1,018,369.50	863,538.00	1.179299
4 COPPER CONDUCTOR	41.74	20,512,898.86	11,855,843.00	1.7301932
4A COPPER CONDUCTOR	41.74	425,395.34	76,077.00	5.5916419
6 COPPER CONDUCTOR	26.25	11,935,258.01	15,247,078.00	0.7827899
6A COPPER CONDUCTOR	26.25	751,476.51	101,690.00	7.3898762
750 MCM COPPER CONDUCTOR	750	853,486.08	26,479.00	32.232565
795 MCM ALUMINUM CONDUCTOR	795	52,092,231.22	10,827,908.00	4.810923
8 COPPER CONDUCTOR	16.51	714,478.51	356,910.00	2.001845
840,200 24/13 ACAR WIRE	840.2	625,715.08	212,797.00	2.9404319
1/0 CABLE	105.6	46,299,775.20	21,978,822.00	2.1065631
101 MCM ACSR CONDUCTOR	101	1,181.18	250.00	4.72472
1272 MCM ACSR CONDUCTOR	1272	79,529.08	30,823.00	2.5801862
200 MCM CABLE	200	3,238.76	500.00	6.47752
3/0 CONDUCTOR	167.8	6,205,860.32	2,056,133.00	3.0182193
300 MCM COPPER CONDUCTOR	300	3,564.60	260.00	13.71
4/0 CONDUCTOR	211.6	15,519,658.14	6,550,826.00	2.3691147
520 MCM CONDUCTOR	520	688.25	112.00	6.1450893
600 MCM CONDUCTOR	600	105,914.75	16,060.00	6.5949408
636 MCM ALUMINUM CONDUCTOR	636	21,911.09	3,040.00	7.2075954
7/C CONDUCTOR	20.92	18,059.98	4,050.00	4.4592543
80 MCM ACSR CONDUCTOR	80	20,945.38	11,500.00	1.8213374
954 MCM ACSR CONDUCTOR	954	553,522.85	121,743.00	4.5466503

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

July 31, 2020

n	y	x	est y	y*n^.5	n^.5	xn^.5
9,502,231	1.61223	66.37	1.657	4969.822299	3,082.57	204587
27,617	4.64736	41.74	1.554	772.3157654	166.18	6936.505
183,400	7.65556	66.36	1.657	3278.511696	428.25	28418.82
692,306	6.18079	105.60	1.821	5142.72476	832.05	87864.4
22,210	6.03454	105.60	1.821	899.3292067	149.03	15737.59
24,884	4.72145	105.60	1.821	744.7926988	157.75	16658.04
9,362,717	1.83064	123.27	1.895	5601.481447	3,059.86	377188.4
1,873,176	1.40453	195.70	2.197	1922.291387	1,368.64	267842.9
532,633	2.52751	133.10	1.936	1844.621562	729.82	97138.66
1,333,578	2.14093	20.00	1.464	2472.355157	1,154.81	23096.13
5,646,839	1.67567	336.40	2.784	3981.90412	2,376.31	799390
85,617	26.79357	350.00	2.841	7839.901541	292.60	102411.3
863,538	1.17930	392.50	3.018	1095.884179	929.27	364737.5
11,855,843	1.73019	41.74	1.554	5957.455664	3,443.23	143720.5
76,077	5.59164	41.74	1.554	1542.289987	275.82	11512.75
15,247,078	0.78279	26.25	1.490	3056.59924	3,904.75	102499.7
101,690	7.38988	26.25	1.490	2356.547978	318.89	8370.828
26,479	32.23256	750.00	4.509	5245.001932	162.72	122042.8
10,827,908	4.81092	795.00	4.697	15830.72049	3,290.58	2616010
356,910	2.00185	16.51	1.449	1195.941159	597.42	9863.395
212,797	2.94043	840.20	4.886	1356.419021	461.30	387583.6
21,978,822	2.10656	105.60	1.821	9875.899834	4,688.16	495069.4
250	4.72472	101.00	1.802	74.70438253	15.81	1596.95
30,823	2.58019	1,272.00	6.687	452.9898858	175.56	223318.4
500	6.47752	200.00	2.215	144.8417505	22.36	4472.136
2,056,133	3.01822	167.80	2.080	4327.891801	1,433.92	240612.2
260	13.71000	300.00	2.632	221.0671075	16.12	4837.355
6,550,826	2.36911	211.60	2.263	6063.649904	2,559.46	541581.3
112	6.14509	520.00	3.550	65.03351214	10.58	5503.163
16,060	6.59494	600.00	3.884	835.7640283	126.73	76036.83
3,040	7.20760	636.00	4.034	397.3993852	55.14	35066.62
4,050	4.45925	20.92	1.467	283.7852072	63.64	1331.341
11,500	1.82134	80.00	1.714	195.3166756	107.24	8579.044
121,743	4.54665	954.00	5.361	1586.403115	348.92	332866.7

Kentucky Utilities Company
Pri/Sec Splits for Overhead Conductor

		Customer	Demand
Overhead		63.99%	36.01%
Primary	70.54%	0.4514	0.2540
Secondary	29.46%	0.1885	0.1061

Exhibit WSS-24

Zero Intercept Analysis

For

Underground Conductor

(Kentucky Utilities)

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

July 31, 2020

Weighted Linear Regression Statistics

	Estimate	Standard Error	T-Statistic
Size Coefficient ($ per MCM)	0.0135482	0.0034047	3.9792049
Zero Intercept ($ per Unit)	4.6531902	0.5775615	8.0566138
R-Square	0.8987417		

Plant Classification

Total Number of Units	29,539,252
Zero Intercept	4.6531902
Zero Intercept Cost	$ 137,451,759
Total Cost of Sample	$ 183,565,083
Percentage of Total	0.748790328
Percentage Classified as Customer-Related	74.88%
Percentage Classified as Demand-Related	25.12%

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

July 31, 2020

Description	Size	Cost	Quantity	Avg Cost
#12 CABLE	13.12	170,319.13	77,929	2.185568017
#2 Triplex	66.36	88,747,142.22	15,945,949	5.565497683
#2 ACSR	66.36	1,564,961.37	157,316	9.947884322
1/0 CABLE	105.6	13,237,152.96	949,513	13.94099181
1/0 CONDUCTOR	105.6	4,096,996.41	206,882	19.80354216
1/0 Triplex	105.6	518,357.22	22,986	22.55099713
1000 MCM CONDUCTOR	1000	6,480,812.47	364,678	17.77132832
1500 MCM UGAL CABLE	1500	44,861.19	4,026	11.14286885
2/0 COPPER CONDUCTOR	133.1	35,657,910.66	6,421,560	5.552842403
20 M.A.W. MESSENGER WIRE	20	1,880.60	2,834	0.663585039
200 MCM CABLE	200	44,255.13	5,194	8.520433192
2000 MCM 1/C 1000V CABLE	2000	501.81	578	0.868183391
266 MCM ACSR CONDUCTOR	266	7,717.86	400	19.29465
3/0 CONDUCTOR	167.8	994,247.11	224,357	4.431540402
300 MCM COPPER CONDUCTOR	300	8,963.91	126	71.14214286
350 MCM COPPER CONDUCTOR	350	4,484,214.59	431,382	10.39499699
397 MCM ACSR CONDUCTOR	397	736,737.37	77,390	9.51980062
4 COPPER CONDUCTOR	41.74	361,501.33	44,452	8.132397417
4/0 CONDUCTOR	211.6	22,155,450.85	2,874,908	7.706490382
4A COPPER CONDUCTOR	41.74	9,810.69	4,140	2.369731884
500 MCM COPPER CONDUCTOR	500	724,136.77	68,224	10.61410603
520 MCM CONDUCTOR	520	451.53	75	6.0204
6 COPPER CONDUCTOR	26.25	1,814,646.22	1,251,654	1.449798602
600 MCM CONDUCTOR	600	76,600.45	3,983	19.23184785
6A COPPER CONDUCTOR	26.25	337,831.10	299328	1.128631802
750 MCM COPPER CONDUCTOR	750	1,248,122.15	96109	12.98652728
795 MCM ALUMINUM CONDUCTOR	795	38,247.86	2606	14.67684574
8 COPPER CONDUCTOR	795	1,252.12	673	1.860505201

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

July 31, 2020

n	y	x	est y	y*n^.5	n^.5	xn^.5
77,929	2.18557	13.12	4.831	610.1180568	279.16	3662.548519
15,945,949	5.56550	66.36	5.552	22224.35633	3,993.24	264991.2677
157,316	9.94788	66.36	5.552	3945.637423	396.63	26320.4206
949,513	13.94099	105.60	6.084	13584.51475	974.43	102899.7633
206,882	19.80354	105.60	6.084	9007.499162	454.84	48031.40285
22,986	22.55100	105.60	6.084	3418.987011	151.61	16010.15806
364,678	17.77133	1,000.00	18.201	10731.85195	603.89	603885.7508
4,026	11.14287	1,500.00	24.975	707.0235899	63.45	95176.15248
6,421,560	5.55284	133.10	6.456	14071.34529	2,534.08	337286.01
2,834	0.66359	20.00	4.924	35.32616628	53.24	1064.706532
5,194	8.52043	200.00	7.363	614.0626015	72.07	14413.8822
578	0.86818	2,000.00	31.750	20.87254435	24.04	48083.26112
400	19.29465	266.00	8.257	385.893	20.00	5320
224,357	4.43154	167.80	6.927	2099.058417	473.66	79480.7156
126	71.14214	300.00	8.718	798.568573	11.22	3367.491648
431,382	10.39500	350.00	9.395	6827.400468	656.80	229878.8703
77,390	9.51980	397.00	10.032	2648.318877	278.19	110441.6611
44,452	8.13240	41.74	5.219	1714.605635	210.84	8800.312567
2,874,908	7.70649	211.60	7.520	13066.78112	1,695.56	358779.5155
4,140	2.36973	41.74	5.219	152.47526	64.34	2685.669798
68,224	10.61411	500.00	11.427	2772.375238	261.20	130598.6217
75	6.02040	520.00	11.698	52.13819341	8.66	4503.3321
1,251,654	1.44980	26.25	5.009	1621.996163	1,118.77	29367.80268
3,983	19.23185	600.00	12.782	1213.741406	63.11	37866.60798
299,328	1.12863	26.25	5.009	617.4843505	547.11	14361.60506
96,109	12.98653	750.00	14.814	4026.011965	310.01	232510.8868
2,606	14.67685	795.00	15.424	749.2382406	51.05	40583.95188
673	1.86051	795.00	15.424	48.26567903	25.94	20624.08362

Kentucky Utilities Company
Pri/Sec Splits for Underground Conductor

		Customer	Demand
Underground		74.88%	25.12%
Primary	60.51%	0.4531	0.1520
Secondary	39.49%	0.2957	0.0992

Exhibit WSS-25

Zero Intercept Analysis

For

Line Transformers

(Kentucky Utilities)

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

July 31, 2020

Weighted Linear Regression Statistics

	Estimate	Standard Error	T-Statistic
Size Coefficient ($ per kVA)	11.7345763	0.4657978	25.19242516
Zero Intercept ($ per Unit)	461.59	63.5020377	7.268833323
R-Square	0.9507396		

Plant Classification

Total Number of Units	249,063
Zero Intercept	$ 461.59
Zero Intercept Cost	$ 114,963,926
Total Cost of Sample	$ 253,336,808
Percentage of Total	0.453798748
Percentage Classified as Customer-Related	45.38%
Percentage Classified as Demand-Related	54.62%

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

July 31, 2020

Description	Size	Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - .6 KVA	0.6	473.46	1	473.46
TRANSFORMERS - OH 1P - 1 KVA	1	14547.14	34	427.86
TRANSFORMERS - OH 1P - 1.5 KVA	1.5	111.09	1	111.09
TRANSFORMERS - OH 1P - 10 KVA	10	7656216.94	20187	379.26
TRANSFORMERS - OH 1P - 100 KVA	100	6238699.31	4220	1478.36
TRANSFORMERS - OH 1P - 1250 KVA	1250	148540.75	14	10610.05
TRANSFORMERS - OH 1P - 15 KVA	15	29737938.25	55627	534.60
TRANSFORMERS - OH 1P - 150 KVA	150	1793.73	3	597.91
TRANSFORMERS - OH 1P - 167 KVA	167	4153323.94	2190	1896.49
TRANSFORMERS - OH 1P - 25 KVA	25	42001035.64	63554	660.87
TRANSFORMERS - OH 1P - 250 KVA	250	1019916.05	286	3566.14
TRANSFORMERS - OH 1P - 3 KVA	3	34061.05	64	532.20
TRANSFORMERS - OH 1P - 333 KVA	333	515097.04	131	3932.04
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	25074741.13	31674	791.65
TRANSFORMERS - OH 1P - 5 KVA	5	318277.27	1770	179.82
TRANSFORMERS - OH 1P - 50 KVA	50	19945734.75	15726	1268.33
TRANSFORMERS - OH 1P - 500 KVA	500	1061113.17	218	4867.49
TRANSFORMERS - OH 1P - 667 KVA	667	92692.95	17	5452.53
TRANSFORMERS - OH 1P - 7.5 KVA	7.5	946.90	2	473.45
TRANSFORMERS - OH 1P - 75 KVA	75	8415318.29	6787	1239.92
TRANSFORMERS - OH 1P - 833 KVA	833	215904.20	19	11363.38
TRANSFORMERS - PM 1P - 10 KVA	10	114272.74	149	766.93
TRANSFORMERS - PM 1P - 100 KVA	100	2840373.40	1485	1912.71
TRANSFORMERS - PM 1P - 15 KVA	15	2711728.77	3007	901.81
TRANSFORMERS - PM 1P - 150 KVA	150	78245.20	16	4890.33
TRANSFORMERS - PM 1P - 167 KVA	167	2686250.55	1087	2471.25
TRANSFORMERS - PM 1P - 225 KVA	225	27212.10	4	6803.03
TRANSFORMERS - PM 1P - 25 KVA	25	11914778.09	11668	1021.15
TRANSFORMERS - PM 1P - 250 KVA	250	2101925.21	527	3988.47
TRANSFORMERS - PM 1P - 333 KVA	333	3901.90	2	1950.95
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	11062540.89	9937	1113.27
TRANSFORMERS - PM 1P - 50 KVA	50	9958889.97	8204	1213.91
TRANSFORMERS - PM 1P - 75 KVA	75	4866865.69	3242	1501.19
TRANSFORMERS - PM 3P - 1000 KVA	1000	4797246.42	382	12558.24
TRANSFORMERS - PM 3P - 112 KVA	112	72785.98	25	2911.44
TRANSFORMERS - PM 3P - 112.5 KVA	112.5	766431.89	213	3598.27
TRANSFORMERS - PM 3P - 1250 KVA	1250	14355.37	2	7177.69
TRANSFORMERS - PM 3P - 150 KVA	150	4396405.79	963	4565.32
TRANSFORMERS - PM 3P - 1500 KVA	1500	5590700.76	315	17748.26
TRANSFORMERS - PM 3P - 2000 KVA	2000	3328373.35	138	24118.65
TRANSFORMERS - PM 3P - 225 KVA	225	3119782.71	626	4983.68
TRANSFORMERS - PM 3P - 2500 KVA	2500	3955764.43	180	21976.47
TRANSFORMERS - PM 3P - 300 KVA	300	6384804.22	1085	5884.61
TRANSFORMERS - PM 3P - 3000 KVA	3000	938652.94	25	37546.12
TRANSFORMERS - PM 3P - 333 KVA	333	117861.40	33	3571.56
TRANSFORMERS - PM 3P - 45 KVA	45	363190.52	114	3185.88
TRANSFORMERS - PM 3P - 500 KVA	500	8876810.49	1098	8084.53
TRANSFORMERS - PM 3P - 75 KVA	75	3124217.98	862	3624.38
TRANSFORMERS - PM 3P - 750 KVA	750	12443128.19	1143	10886.38
TRANSFORMERS - PM 3P - 833 KVA	833	32827.56	6	5471.26

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

July 31, 2020

n	y	x	est y	y*n^.5	n^.5	xn^.5
1	473	0.60	289	473.46	1.00	0.6
34	428	1.00	473	2494.813928	5.83	5.830951895
1	111	1.50	704	111.09	1.00	1.5
20,187	379	10.00	4,628	53886.29685	142.08	1420.809628
4,220	1,478	100.00	46,170	96036.83274	64.96	6496.152708
14	10,610	1,250.00	576,994	39699.18532	3.74	4677.071733
55,627	535	15.00	6,936	126086.3393	235.85	3537.806524
3	598	150.00	69,250	1035.610498	1.73	259.8076211
2,190	1,896	167.00	77,097	88751.10071	46.80	7815.171783
63,554	661	25.00	11,551	166605.2008	252.10	6302.479671
286	3,566	250.00	115,408	60308.90032	16.91	4227.883631
64	532	3.00	1,396	4257.63125	8.00	24
131	3,932	333.00	153,720	45004.23734	11.45	3811.359206
31,674	792	37.50	17,321	140891.5678	177.97	6673.946546
1,770	180	5.00	2,320	7565.175216	42.07	210.3568397
15,726	1,268	50.00	23,091	159052.6479	125.40	6270.167462
218	4,867	500.00	230,805	71867.6523	14.76	7382.41153
17	5,453	667.00	307,889	22481.34256	4.12	2750.111452
2	473	7.50	3,474	669.5594111	1.41	10.60660172
6,787	1,240	75.00	34,631	102148.4126	82.38	6178.743804
19	11,363	833.00	384,513	49531.82049	4.36	3630.96282
149	767	10.00	4,628	9361.587625	12.21	122.0655562
1,485	1,913	100.00	46,170	73707.58976	38.54	3853.569774
3,007	902	15.00	6,936	49451.50743	54.84	822.5417923
16	4,890	150.00	69,250	19561.3	4.00	600
1,087	2,471	167.00	77,097	81476.38382	32.97	5505.937068
4	6,803	225.00	103,869	13606.05	2.00	450
11,668	1,021	25.00	11,551	110303.1075	108.02	2700.462923
527	3,988	250.00	115,408	91561.30026	22.96	5739.120142
2	1,951	333.00	153,720	2759.05995	1.41	470.9331163
9,937	1,113	37.50	17,321	110975.5342	99.68	3738.168836
8,204	1,214	50.00	23,091	109950.7278	90.58	4528.79675
3,242	1,501	75.00	34,631	85475.73737	56.94	4270.392254
382	12,558	1,000.00	461,597	245448.4794	19.54	19544.82029
25	2,911	112.00	51,709	14557.196	5.00	560
213	3,598	112.50	51,940	52515.04779	14.59	1641.883446
2	7,178	1,250.00	576,994	10150.77947	1.41	1767.766953
963	4,565	150.00	69,250	141672.1966	31.03	4654.836195
315	17,748	1,500.00	692,390	315000.3023	17.75	26622.35902
138	24,119	2,000.00	923,183	283329.9551	11.75	23494.68025
626	4,984	225.00	103,869	124691.595	25.02	5629.498201
180	21,976	2,500.00	1,153,976	294845.2723	13.42	33541.01966
1,085	5,885	300.00	138,487	193835.2308	32.94	9881.801455
25	37,546	3,000.00	1,384,769	187730.588	5.00	15000
33	3,572	333.00	153,720	20517.03624	5.74	1912.939361
114	3,186	45.00	20,783	34015.90879	10.68	480.4685213
1,098	8,085	500.00	230,805	267889.5534	33.14	16568.04153
862	3,624	75.00	34,631	106411.2867	29.36	2201.987738
1,143	10,886	750.00	346,201	368049.6932	33.81	25356.21226
6	5,471	833.00	384,513	13401.79525	2.45	2040.424956

Exhibit WSS-26

Zero Intercept Analysis
For
Overhead Conductor
(Louisville Gas and Electric Company)

Louisville Gas and Electric Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

July 31, 2020

Weighted Linear Regression Statistics

	Estimate	Standard Error	T-Statistic
Size Coefficient ($ per MCM)	0.0041724	0.0008336	5.00525
Zero Intercept ($ per Unit)	1.3801706	0.2486132	5.55148
R-Square	0.8225292		

Plant Classification

Total Number of Units	99,629,647
Zero Intercept	1.3801706
Zero Intercept Cost	$ 137,505,908
Total Cost of Sample	$ 214,874,064
Percentage of Total	0.639937206
Percentage Classified as Customer-Related	63.99%
Percentage Classified as Demand-Related	36.01%

Zero Intercept Analysis
Account 365 -- Overhead Conductor

July 31, 2020

Description	Size	Cost	Quantity	Avg Cost
#2 Triplex	66.369	15,319,819.64	9,502,231.00	1.612234
#4 Aluminum Poly	41.74	128,346.24	27,617.00	4.6473636
#2 ACSR	66.36	1,404,030.05	183,400.00	7.6555619
1/0 CONDUCTOR	105.6	4,279,000.42	692,306.00	6.1807935
1/0 Triplex	105.6	134,027.21	22,210.00	6.0345434
1/0 Aluminum	105.6	117,488.54	24,884.00	4.7214491
123,270 ACAR WIRE	123.27	17,139,725.02	9,362,717.00	1.8306358
195,700 ACAR WIRE	195.7	2,630,925.27	1,873,176.00	1.4045265
2/0 COPPER CONDUCTOR	133.1	1,346,236.36	532,633.00	2.5275121
20 M.A.W. MESSENGER WIRE	20	2,855,091.75	1,333,578.00	2.140926
336,400 19 STR. ALL ALUMINUM	336.4	9,462,230.02	5,646,839.00	1.6756685
350 MCM COPPER CONDUCTOR	350	2,293,985.20	85,617.00	26.793571
392,500 24/13 ACAR WIRE	392.5	1,018,369.50	863,538.00	1.179299
4 COPPER CONDUCTOR	41.74	20,512,898.86	11,855,843.00	1.7301932
4A COPPER CONDUCTOR	41.74	425,395.34	76,077.00	5.5916419
6 COPPER CONDUCTOR	26.25	11,935,258.01	15,247,078.00	0.7827899
6A COPPER CONDUCTOR	26.25	751,476.51	101,690.00	7.3898762
750 MCM COPPER CONDUCTOR	750	853,486.08	26,479.00	32.232565
795 MCM ALUMINUM CONDUCTOR	795	52,092,231.22	10,827,908.00	4.810923
8 COPPER CONDUCTOR	16.51	714,478.51	356,910.00	2.001845
840,200 24/13 ACAR WIRE	840.2	625,715.08	212,797.00	2.9404319
1/0 CABLE	105.6	46,299,775.20	21,978,822.00	2.1065631
101 MCM ACSR CONDUCTOR	101	1,181.18	250.00	4.72472
1272 MCM ACSR CONDUCTOR	1272	79,529.08	30,823.00	2.5801862
200 MCM CABLE	200	3,238.76	500.00	6.47752
3/0 CONDUCTOR	167.8	6,205,860.32	2,056,133.00	3.0182193
300 MCM COPPER CONDUCTOR	300	3,564.60	260.00	13.71
4/0 CONDUCTOR	211.6	15,519,658.14	6,550,826.00	2.3691147
520 MCM CONDUCTOR	520	688.25	112.00	6.1450893
600 MCM CONDUCTOR	600	105,914.75	16,060.00	6.5949408
636 MCM ALUMINUM CONDUCTOR	636	21,911.09	3,040.00	7.2075954
7/C CONDUCTOR	20.92	18,059.98	4,050.00	4.4592543
80 MCM ACSR CONDUCTOR	80	20,945.38	11,500.00	1.8213374
954 MCM ACSR CONDUCTOR	954	553,522.85	121,743.00	4.5466503

Zero Intercept Analysis
Account 365 -- Overhead Conductor

July 31, 2020

n	y	x	est y	y*n^.5	n^.5	xn^.5
9,502,231	1.61223	66.37	1.657	4969.822299	3,082.57	204587
27,617	4.64736	41.74	1.554	772.3157654	166.18	6936.505
183,400	7.65556	66.36	1.657	3278.511696	428.25	28418.82
692,306	6.18079	105.60	1.821	5142.72476	832.05	87864.4
22,210	6.03454	105.60	1.821	899.3292067	149.03	15737.59
24,884	4.72145	105.60	1.821	744.7926988	157.75	16658.04
9,362,717	1.83064	123.27	1.895	5601.481447	3,059.86	377188.4
1,873,176	1.40453	195.70	2.197	1922.291387	1,368.64	267842.9
532,633	2.52751	133.10	1.936	1844.621562	729.82	97138.66
1,333,578	2.14093	20.00	1.464	2472.355157	1,154.81	23096.13
5,646,839	1.67567	336.40	2.784	3981.90412	2,376.31	799390
85,617	26.79357	350.00	2.841	7839.901541	292.60	102411.3
863,538	1.17930	392.50	3.018	1095.884179	929.27	364737.5
11,855,843	1.73019	41.74	1.554	5957.455664	3,443.23	143720.5
76,077	5.59164	41.74	1.554	1542.289987	275.82	11512.75
15,247,078	0.78279	26.25	1.490	3056.59924	3,904.75	102499.7
101,690	7.38988	26.25	1.490	2356.547978	318.89	8370.828
26,479	32.23256	750.00	4.509	5245.001932	162.72	122042.8
10,827,908	4.81092	795.00	4.697	15830.72049	3,290.58	2616010
356,910	2.00185	16.51	1.449	1195.941159	597.42	9863.395
212,797	2.94043	840.20	4.886	1356.419021	461.30	387583.6
21,978,822	2.10656	105.60	1.821	9875.899834	4,688.16	495069.4
250	4.72472	101.00	1.802	74.70438253	15.81	1596.95
30,823	2.58019	1,272.00	6.687	452.9898858	175.56	223318.4
500	6.47752	200.00	2.215	144.8417505	22.36	4472.136
2,056,133	3.01822	167.80	2.080	4327.891801	1,433.92	240612.2
260	13.71000	300.00	2.632	221.0671075	16.12	4837.355
6,550,826	2.36911	211.60	2.263	6063.649904	2,559.46	541581.3
112	6.14509	520.00	3.550	65.03351214	10.58	5503.163
16,060	6.59494	600.00	3.884	835.7640283	126.73	76036.83
3,040	7.20760	636.00	4.034	397.3993852	55.14	35066.62
4,050	4.45925	20.92	1.467	283.7852072	63.64	1331.341
11,500	1.82134	80.00	1.714	195.3166756	107.24	8579.044
121,743	4.54665	954.00	5.361	1586.403115	348.92	332866.7

Louisville Gas & Electric Company
Pri/Sec Splits for Overhead Conductor

		Customer	Demand
Overhead		63.99%	36.01%
Primary	70.52%	0.451257	0.253943
Secondary	29.48%	0.188643	0.106157

Exhibit WSS-27

Zero Intercept Analysis
For
Underground Conductor
(Louisville Gas and Electric Company)

Louisville Gas and Electric Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

July 31, 2020

Weighted Linear Regression Statistics

	Estimate	Standard Error	T-Statistic
Size Coefficient ($ per MCM)	0.0120160	0.0020905	5.74802331
Zero Intercept ($ per Unit)	3.6032354	0.6693966	5.38281094
R-Square	0.8880539		

Plant Classification

Total Number of Units	28,418,282
Zero Intercept	3.6032354
Zero Intercept Cost	$102,397,759
Total Cost of Sample	171,072,223
Percentage of Total	0.598564498
Percentage Classified as Customer-Related	59.86%
Percentage Classified as Demand-Related	40.14%

Zero Intercept Analysis
Account 367 -- Underground Conductor

July 31, 2020

Description	Size	Cost	Quantity	Avg Cost
#12 CABLE	13.12	2,112,678.09	745,191	2.83508267
#2 ACSR	66.36	1,557,878.07	156,578	9.949533587
1/0 CONDUCTOR	105.6	7,195,209.68	492,534	14.60855429
1000 MCM CONDUCTOR	1000	31,580,920.64	2,179,943	14.48703963
2/0 COPPER CONDUCTOR	133.1	3,012,847.79	599,963	5.021722656
200 MCM 1/C 500/600V CABLE	200	28,562.39	1,550	18.42734839
250 MCM COPPER CONDUCTOR	250	161,508.10	111,488	1.448659049
350 MCM COPPER CONDUCTOR	350	16,509,361.29	1,003,510	16.45161612
4 COPPER CONDUCTOR	41.74	827,737.92	655,174	1.263386398
6 COPPER CONDUCTOR	26.25	1,303,875.94	551,368	2.364801621
750 MCM COPPER CONDUCTOR	750	4,691,977.35	268,440	17.47868183
795 MCM ALUMINUM CONDUCTOR	795	502,850.86	53,029	9.482563503
8 COPPER CONDUCTOR	16.51	26,725.53	18,183	1.469808612
#2 Triplex	66.36	17,758,638.68	3,500,675	5.072918417
1/0 CABLE	105.6	56,010,718.58	12,543,200	4.465424978
123,270 ACAR WIRE	123.27	7,397.12	496	14.91354839
195,700 ACAR WIRE	195.7	10,289.60	7,611	1.351937984
3/0 CONDUCTOR	167.8	327,842.85	31,894	10.27913871
336,400 19 STR. ALL ALUMINUM	336.4	95,736.62	2,289	41.82464832
4/0 CONDUCTOR	211.6	27,020,420.38	5440647	4.966398368
600 MCM CONDUCTOR	600	21,636.43	1634	13.24138923
6A COPPER CONDUCTOR	26.25	307,231.56	52777	5.821315346
840,200 24/13 ACAR WIRE	840.2	177.03	108	1.639166667

Zero Intercept Analysis
Account 367 -- Underground Conductor

July 31, 2020

n	y	x	est y	y*n^.5	n^.5	xn^.5
745,191	2.83508	13.12	3.761	2447.369412	863.24	11325.76733
156,578	9.94953	66.36	4.401	3937.02428	395.70	26258.61091
492,534	14.60855	105.60	4.872	10252.39539	701.81	74110.88953
2,179,943	14.48704	1,000.00	15.619	21389.57805	1,476.46	1476463.003
599,963	5.02172	133.10	5.203	3889.689706	774.57	103095.6377
1,550	18.42735	200.00	6.006	725.4854315	39.37	7874.007874
111,488	1.44866	250.00	6.607	483.7046314	333.90	83474.54702
1,003,510	16.45162	350.00	7.809	16480.46341	1,001.75	350613.7119
655,174	1.26339	41.74	4.105	1022.62057	809.43	33785.53279
551,368	2.36480	26.25	3.919	1755.963535	742.54	19491.71651
268,440	17.47868	750.00	12.615	9055.914048	518.11	388583.9678
53,029	9.48256	795.00	13.156	2183.647227	230.28	183072.8099
18,183	1.46981	16.51	3.802	198.1953939	134.84	2226.280296
3,500,675	5.07292	66.36	4.401	9491.476451	1,871.01	124160.1629
12,543,200	4.46542	105.60	4.872	15814.91896	3,541.64	373996.9769
496	14.91355	123.27	5.084	332.1404929	22.27	2745.353252
7,611	1.35194	195.70	5.955	117.9444831	87.24	17073.07258
31,894	10.27914	167.80	5.620	1835.740213	178.59	29967.21967
2,289	41.82465	336.40	7.645	2001.037347	47.84	16094.55167
5,440,647	4.96640	211.60	6.146	11584.22081	2,332.52	493561.1163
1,634	13.24139	600.00	10.813	535.2535765	40.42	24253.65952
52,777	5.82132	26.25	3.919	1337.345055	229.73	6030.476893
108	1.63917	840.20	13.699	17.03471969	10.39	8731.614531

Louisville Gas & Electric Company
Pri/Sec Splits for Underground Conductor

		Customer	Demand
Underground		59.86%	40.14%
Primary	88.07%	0.527187	0.353513
Secondary	11.93%	0.071413	0.047887

Exhibit WSS-28

Zero Intercept Analysis

For

Line Transformers

(Louisville Gas and Electric Company)

LOUISVILLE GAS AND ELECTRIC COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

July 31, 2020

Weighted Linear Regression Statistics

	Estimate	Standard Error	T-Statistic
Size Coefficient ($ per kVA)	17.6357155	1.1732790	15.03113556
Zero Intercept ($ per Unit)	771.57	239.3973453	3.2229544
R-Square	0.9017152		

Plant Classification

Total Number of Units	36,724
Zero Intercept	$ 771.57
Zero Intercept Cost	$ 28,335,016
Total Cost of Sample	$ 79,168,555
Percentage of Total	0.357907459
Percentage Classified as Customer-Related	35.79%
Percentage Classified as Demand-Related	64.21%

Zero Intercept Analysis
Account 368 - Line Transformers

July 31, 2020

	Size	Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - 100 KVA	100	1356037.78	528	2568.25
TRANSFORMERS - OH 1P - 1 KVA	1	101798.01	191	532.97
TRANSFORMERS - OH 1P - 15 KVA	15	2829522.18	3564	793.92
TRANSFORMERS - OH 1P - 150 KVA	150	239101.48	64	3735.96
TRANSFORMERS - OH 1P - 167 KVA	167	888091.76	327	2715.88
TRANSFORMERS - OH 1P - 25 KVA	25	6591201.39	6546	1006.91
TRANSFORMERS - OH 1P - 250 KVA	250	143562.02	30	4785.40
TRANSFORMERS - OH 1P - 3 KVA	3	27315.31	28	975.55
TRANSFORMERS - OH 1P - 333 KVA	333	14112.54	2	7056.27
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	6831989.67	6068	1125.90
TRANSFORMERS - OH 1P - 50 KVA	50	5257198.70	3367	1561.39
TRANSFORMERS - OH 1P - 500 KVA	500	379912.35	97	3916.62
TRANSFORMERS - OH 1P - 75 KVA	75	2131164.69	1082	1969.65
TRANSFORMERS - PM 1P - 100 KVA	100	2358129.09	916	2574.38
TRANSFORMERS - PM 1P - 150 KVA	150	583737.81	175	3335.64
TRANSFORMERS - PM 1P - 225 KVA	225	540183.84	104	5194.08
TRANSFORMERS - PM 1P - 25 KVA	25	2078735.66	1992	1043.54
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	3499914.69	2529	1383.91
TRANSFORMERS - PM 1P - 50 KVA	50	6222858.08	3536	1759.86
TRANSFORMERS - PM 1P - 75 KVA	75	6008078.93	2912	2063.21
TRANSFORMERS - PM 3P - 1000 KVA	1000	6642706.89	236	28147.06
TRANSFORMERS - PM 3P - 150 KVA	150	1474889.68	244	6044.63
TRANSFORMERS - PM 3P - 1500 KVA	1500	2229052.20	106	21028.79
TRANSFORMERS - PM 3P - 2000 KVA	2000	1608542.18	57	28220.04
TRANSFORMERS - PM 3P - 225 KVA	225	873694.81	107	8165.37
TRANSFORMERS - PM 3P - 2500 KVA	2500	1429641.03	45	31769.80
TRANSFORMERS - PM 3P - 300 KVA	300	3626588.95	424	8553.28
TRANSFORMERS - PM 3P - 3000 KVA	3000	496323.05	12	41360.25
TRANSFORMERS - PM 3P - 500 KVA	500	4537659.88	315	14405.27
TRANSFORMERS - OH 1P - 7.5 KVA	7.5	2397.60	1	2397.60
TRANSFORMERS - PM 3P - 75 KVA	75	725338.18	106	6842.81
TRANSFORMERS - PM 3P - 750 KVA	750	4852790.96	297	16339.36
TRANSFORMERS - OH 1P - 10 KVA	10	83109.37	125	664.87
TRANSFORMERS - PM 1P - 15 KVA	15	83044.45	112	741.47
TRANSFORMERS - PM 1P - 167 KVA	167	1404628.80	380	3696.39
TRANSFORMERS - PM 1P - 250 KVA	250	473303.55	65	7281.59
TRANSFORMERS - PM 1P - 500 KVA	500	542197.87	34	15947.00

Zero Intercept Analysis
Account 368 - Line Transformers

July 31, 2020

n	y	x	est y	y*n^.5	n^.5	xn^.5
528	2,568	100.00	77,174	59013.96953	22.98	2297.825059
191	533	1.00	789	7365.845491	13.82	13.82027496
3,564	794	15.00	11,591	47396.27983	59.70	895.4886934
64	3,736	150.00	115,753	29887.685	8.00	1200
327	2,716	167.00	128,869	49111.58655	18.08	3019.8846
6,546	1,007	25.00	19,307	81466.03528	80.91	2022.683861
30	4,785	250.00	192,909	26210.71892	5.48	1369.306394
28	976	3.00	2,332	5162.108375	5.29	15.87450787
2	7,056	333.00	256,949	9979.072734	1.41	470.9331163
6,068	1,126	37.50	28,951	87705.01254	77.90	2921.151314
3,367	1,561	50.00	38,596	90600.96713	58.03	2901.292815
97	3,917	500.00	385,801	38574.25477	9.85	4924.428901
1,082	1,970	75.00	57,885	64789.314	32.89	2467.032631
916	2,574	100.00	77,174	77914.77825	30.27	3026.54919
175	3,336	150.00	115,753	44126.43075	13.23	1984.313483
104	5,194	225.00	173,620	52969.38348	10.20	2294.558781
1,992	1,044	25.00	19,307	46575.18614	44.63	1115.79568
2,529	1,384	37.50	28,951	69595.80201	50.29	1885.843644
3,536	1,760	50.00	38,596	104648.6833	59.46	2973.213749
2,912	2,063	75.00	57,885	111337.11	53.96	4047.221269
236	28,147	1,000.00	771,584	432403.388	15.36	15362.2915
244	6,045	150.00	115,753	94420.13644	15.62	2343.074903
106	21,029	1,500.00	1,157,368	216504.6888	10.30	15443.44521
57	28,220	2,000.00	1,543,151	213056.6165	7.55	15099.66887
107	8,165	225.00	173,620	84463.26531	10.34	2327.418097
45	31,770	2,500.00	1,928,934	213118.3018	6.71	16770.50983
424	8,553	300.00	231,488	176122.7288	20.59	6177.378085
12	41,360	3,000.00	2,314,718	143276.1233	3.46	10392.30485
315	14,405	500.00	385,801	255668.1703	17.75	8874.119675
1	2,398	7.50	5,804	2397.6	1.00	7.5
106	6,843	75.00	57,885	70451.07197	10.30	772.1722606
297	16,339	750.00	578,693	281587.4917	17.23	12925.26595
125	665	10.00	7,733	7433.528035	11.18	111.8033989
112	741	15.00	11,591	7846.962945	10.58	158.7450787
380	3,696	167.00	128,869	72055.93708	19.49	3255.429311
65	7,282	250.00	192,909	58706.0802	8.06	2015.564437
34	15,947	500.00	385,801	92986.16757	5.83	2915.475947

Exhibit WSS-29

Electric Cost of Service Study
Functional Assignment and
Classification
(Kentucky Utilities)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Plant in Service													
Intangible Plant													
301.00 ORGANIZATION	P301	PT&D	$ 41,552	26,150	-	5,660	-	1,527	-	1,215	2,361	547	1,104
302.00 FRANCHISE AND CONSENTS	P301	PT&D	144,369	90,855	-	19,667	-	5,306	-	4,220	8,202	1,900	3,835
303.00 SOFTWARE	P302	PT&D	105,565,478	66,435,041	-	14,380,841	-	3,879,489	-	3,085,565	5,997,613	1,389,074	2,804,196
Total Intangible Plant	PINT		$ 105,751,399	$ 66,552,045	$ -	$ 14,406,168	$ -	$ 3,886,322	$ -	$ 3,090,999	$ 6,008,176	$ 1,391,520	$ 2,809,134
Steam Production Plant													
Total Steam Production Plant	PSTPR	F017	$ 4,761,764,495	4,761,764,495	-	-	-	-	-	-	-	-	-
Hydraulic Production Plant													
Total Hydraulic Production Plant	PHDPR	F017	$ 45,726,563	45,726,563	-	-	-	-	-	-	-	-	-
Other Production Plant													
Total Other Production Plant	POTPR	F017	$ 1,044,547,033	1,044,547,033	-	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ 5,852,038,091	$ 5,852,038,091	$ -	$ -	$ -		$ -	$ -			
Transmission													
KENTUCKY SYSTEM PROPERTY	P350	F011	$ 1,258,529,222	-	-	1,258,529,222	-	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	8,230,429	-	-	8,230,429	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 1,266,759,651	$ -	$ -	$ 1,266,759,651	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution													
TOTAL ACCTS 360-362	P362	F001	$ 341,731,104	-	-	-	-	341,731,104	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	921,791,437	-	-	-	-	-	-	234,148,428	416,083,252	97,788,669	173,771,089
366 & 367-UNDERGROUND LINES	P367	F004	247,685,955	-	-	-	-	-	-	37,648,543	112,226,229	24,570,169	73,241,014
368-TRANSFORMERS - POWER POOL	P368	F005	5,363,042	-	-	-	-	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	321,195,483	-	-	-	-	-	-	-	-	-	-
369-SERVICES	P369	F006	124,944,572	-	-	-	-	-	-	-	-	-	-
370-METERS	P370	F007	74,150,151	-	-	-	-	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F007	159,234	-	-	-	-	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	143,087,299	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 2,180,108,277	$ -	$ -	$ -	$ -	$ 341,731,104	$ -	$ 271,796,970	$ 528,309,481	$ 122,358,838	$ 247,012,103
Total Prod, Trans, and Dist Plant	PT&D		$ 9,298,906,019	$ 5,852,038,091	$ -	$ 1,266,759,651	$ -	$ 341,731,104	$ -	$ 271,796,970	$ 528,309,481	$ 122,358,838	$ 247,012,103

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service										
Intangible Plant										
301.00 ORGANIZATION	P301	PT&D	797	662	558	332	639	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	2,769	2,301	1,940	1,154	2,221	-	-	-
303.00 SOFTWARE	P302	PT&D	2,024,901	1,682,342	1,418,429	843,594	1,624,393	-	-	-
Total Intangible Plant	PINT		$ 2,028,467	$ 1,685,305	$ 1,420,927	$ 845,080	$ 1,627,254	$ -	$ -	$ -
Steam Production Plant										
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-	-
Hydraulic Production Plant										
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-	-
Other Production Plant										
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -			$ -	$ -	$ -	$ -
Transmission										
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution										
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	2,929,300	2,433,742	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	175,437,375	145,758,108	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	124,944,572	-	-	-	-	-
370-METERS	P370	F007	-	-	-	74,150,151	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F007	-	-	-	159,234	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	143,087,299	-	-	-
Total Distribution Plant	PDIST		$ 178,366,675	$ 148,191,850	$ 124,944,572	$ 74,309,385	$ 143,087,299	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 178,366,675	$ 148,191,850	$ 124,944,572	$ 74,309,385	$ 143,087,299	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Plant in Service (Continued)													
General Plant													
Total General Plant	PGP	PT&D	$ 244,918,755	154,133,602	-	33,364,484	-	9,000,667	-	7,158,710	13,914,852	3,222,742	6,505,915
TOTAL COMMON PLANT	PCOM	PT&D	$ -	-	-	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	$ 290,384	290,384	-	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	$ 906,481	-	-	-	-	142,091	-	113,012	219,669	50,876	102,707
105.00 PLANT HELD FOR FUTURE USE - GENERAL	P105	PT&D	$ -	-	-	-	-	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 9,650,773,038	$ 6,073,014,123	$ -	$ 1,314,530,303	$ -	$ 354,760,183	$ -	$ 282,159,692	$ 548,452,178	$ 127,023,977	$ 256,429,859
Construction Work in Progress (CWIP)													
CWIP Production	CWIP1	F017	$ 20,992,633	20,992,633	-	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	78,958,656	-	-	78,958,656	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	26,143,041	-	-	-	-	4,097,911	-	3,259,287	6,335,289	1,467,281	2,962,077
CWIP General Plant	CWIP4	PT&D	29,729,390	18,709,461	-	4,049,938	-	1,092,543	-	868,958	1,689,050	391,192	789,719
RWIP	CWIP5	F004	-	-	-	-	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 155,823,720	$ 39,702,094	$ -	$ 83,008,594	$ -	$ 5,190,455	$ -	$ 4,128,245	$ 8,024,339	$ 1,858,473	$ 3,751,795
Total Utility Plant			$ 9,806,596,758	$ 6,112,716,217	$ -	$ 1,397,538,897	$ -	$ 359,950,638	$ -	$ 286,287,937	$ 556,476,517	$ 128,882,450	$ 260,181,655

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)										
General Plant										
Total General Plant	PGP	PT&D	4,697,901	3,903,143	3,290,846	1,957,194	3,768,697	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	74,164	61,618	51,951	30,898	59,495	-	-	-
105.00 PLANT HELD FOR FUTURE USE - GENERAL	P105	PT&D	-	-	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 185,167,208	$ 153,841,916	$ 129,708,296	$ 77,142,557	$ 148,542,746	$ -	$ -	$ -
Construction Work in Progress (CWIP)										
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	2,138,906	1,777,061	1,498,288	891,090	1,715,849	-	-	-
CWIP General Plant	CWIP4	PT&D	570,253	473,782	399,458	237,573	457,462	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 2,709,160	$ 2,250,843	$ 1,897,747	$ 1,128,664	$ 2,173,311	$ -	$ -	$ -
Total Utility Plant			$ 187,876,368	$ 156,092,759	$ 131,606,043	$ 78,271,220	$ 150,716,057	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Rate Base													
Utility Plant													
Plant in Service			$ 9,650,773,038	$ 6,073,014,123	$ -	$ 1,314,530,303	$ -	$ 354,760,183	$ -	$ 282,159,692	$ 548,452,178	$ 127,023,977	$ 256,429,859
Construction Work in Progress (CWIP)			155,823,720	39,702,094.34	-	83,008,593.88	-	5,190,454.54	-	4,128,245.29	8,024,339.34	1,858,472.87	3,751,795.13
Total Utility Plant	TUP		$ 9,806,596,758	$ 6,112,716,217	$ -	$ 1,397,538,897	$ -	$ 359,950,638	$ -	$ 286,287,937	$ 556,476,517	$ 128,882,450	$ 260,181,655
Less: Acummulated Provision for Depreciation													
Steam Production	ADEPREPA	F017	$ 1,910,902,169	1,910,902,169	-	-	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	16,663,604	16,663,604	-	-	-	-	-	-	-	-	-
Other Production		F017	425,504,289	425,504,289	-	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	340,091,705	-	-	340,091,705	-	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	2,567,091	-	-	2,567,091	-	-	-	-	-	-	-
Transmission - FERC	ADEPRD10	PTRAN	755,524	-	-	755,524	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	692,590,515	-	-	-	-	108,563,287	-	86,346,172	167,836,680	38,871,726	78,472,359
General Plant	ADEPRD12	PT&D	77,429,701	48,728,480	-	10,547,996	-	2,845,511	-	2,263,186	4,399,103	1,018,852	2,056,809
Intangible Plant	ADEPRGP	PT&D	49,083,879	30,889,734	-	6,686,537	-	1,803,813	-	1,434,669	2,788,659	645,866	1,303,843
Total Accumulated Depreciation	TADEPR		$ 3,515,588,477	$ 2,432,688,276	$ -	$ 360,648,853	$ -	$ 113,212,611	$ -	$ 90,044,027	$ 175,024,442	$ 40,536,443	$ 81,833,011
Net Utility Plant	NTPLANT		$ 6,291,008,281	$ 3,680,027,941	$ -	$ 1,036,890,044	$ -	$ 246,738,027	$ -	$ 196,243,910	$ 381,452,075	$ 88,346,006	$ 178,348,644
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 130,078,093	19,058,566	79,624,711	8,904,127	-	1,431,095	-	1,998,528	3,667,849	857,386	1,599,580
Materials and Supplies	M&S	TPIS	59,890,781	37,687,920	-	8,157,714	-	2,201,571	-	1,751,027	3,403,585	788,286	1,591,353
Prepayments	PREPAY	TPIS	19,024,116	11,971,448	-	2,591,272	-	699,322	-	556,208	1,081,138	250,396	505,488
Fuel Stock		F017	62,536,188	62,536,188	-	-	-	-	-	-	-	-	-
Total Working Capital	TWC		$ 271,529,178	$ 131,254,122	$ 79,624,711	$ 19,653,112	$ -	$ 4,331,988	$ -	$ 4,305,763	$ 8,152,572	$ 1,896,068	$ 3,696,420
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-	-	-	-	-
Deferred Debits													
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Income Tax													
Total Production Plant	ADITPP	F017	732,330,105	732,330,105	-	-	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	198,625,100	-	-	198,625,100	-	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	315,220,930	-	-	-	-	49,410,755	-	39,299,009	76,388,043	17,691,812	35,715,375
Total General Plant	ADITGP	PT&D	35,890,099	22,586,552	-	4,889,191	-	1,318,947	-	1,049,029	2,039,066	472,257	953,369
Total Accumulated Deferred Income Tax	ADITT		1,282,066,235	754,916,658	-	203,514,291	-	50,729,702	-	40,348,037	78,427,109	18,164,069	36,668,744
Accumulated Deferred Investment Tax Credits													
Production	ADITCP	F017	$ 80,926,985	80,926,985	-	-	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		80,926,985	80,926,985	-	-	-	-	-	-	-	-	-
Total Deferred Debits			$ 1,362,993,220	$ 835,843,643	$ -	$ 203,514,291	$ -	$ 50,729,702	$ -	$ 40,348,037	$ 78,427,109	$ 18,164,069	$ 36,668,744
Less: Customer Advances	CSTDEP	F027	$ 1,712,216	-	-	-	-	-	-	397,934	773,491	179,144	361,647
Less: Asset Retirement Obligations		F017		-	-	-	-	-	-	-	-	-	-
Net Rate Base	RB		$ 5,197,832,023	$ 2,975,438,420	$ 79,624,711	$ 853,028,865	$ -	$ 200,340,313	$ -	$ 159,803,702	$ 310,404,048	$ 71,898,861	$ 145,014,673

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base										
Utility Plant										
Plant in Service			$ 185,167,208	$ 153,841,916	$ 129,708,296	$ 77,142,557	$ 148,542,746	$ -	$ -	$ -
Construction Work in Progress (CWIP)			2,709,159.65	2,250,842.99	1,897,746.84	1,128,663.68	2,173,311.45	-	-	-
Total Utility Plant	TUP		$ 187,876,368	$ 156,092,759	$ 131,606,043	$ 78,271,220	$ 150,716,057	$ -	$ -	$ -
Less: Acummulated Provision for Depreciation										
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-	-	-	-	-	-
Transmission - FERC	ADEPRD10	PTRAN	-	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	56,664,648	47,078,519	39,693,178	23,607,073	45,456,873	-	-	-
General Plant	ADEPRD12	PT&D	1,485,215	1,233,957	1,040,383	618,756	1,191,453	-	-	-
Intangible Plant	ADEPRGP	PT&D	941,501	782,224	659,515	392,239	755,280	-	-	-
Total Accumulated Depreciation	TADEPR		$ 59,091,364	$ 49,094,701	$ 41,393,075	$ 24,618,068	$ 47,403,606	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 128,785,004	$ 106,998,058	$ 90,212,968	$ 53,653,152	$ 103,312,451	$ -	$ -	$ -
Working Capital										
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	408,278	339,209	279,717	1,778,647	320,334	8,704,114	1,105,953	-
Materials and Supplies	M&S	TPIS	1,149,111	954,712	804,944	478,731	921,827	-	-	-
Prepayments	PREPAY	TPIS	365,011	303,261	255,688	152,068	292,815	-	-	-
Fuel Stock		F017	-	-	-	-	-	-	-	-
Total Working Capital	TWC		$ 1,922,401	$ 1,597,182	$ 1,340,349	$ 2,409,446	$ 1,534,976	$ 8,704,114	$ 1,105,953	$ -
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-	-
Deferred Debits										
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-	-
Accumulated Deferred Income Tax										
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	25,789,962	21,426,997	18,065,683	10,744,362	20,688,932	-	-	-
Total General Plant	ADITGP	PT&D	688,425	571,962	482,237	286,805	552,260	-	-	-
Total Accumulated Deferred Income Tax	ADITT		26,478,387	21,998,959	18,547,919	11,031,167	21,241,192	-	-	-
Accumulated Deferred Investment Tax Credits										
Production	ADITCP	F017	-	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-	-	-
Total Deferred Debits			$ 26,478,387	$ 21,998,959	$ 18,547,919	$ 11,031,167	$ 21,241,192	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-	-	-	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-	-	-
Net Rate Base	RB		$ 104,229,018	$ 86,596,282	$ 73,005,398	$ 45,031,431	$ 83,606,234	$ 8,704,114	$ 1,105,953	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses													
Steam Power Generation Operation Expenses													
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 5,418,923	4,838,523	580,400	-	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	296,477,275	-	296,477,275	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		22,989,772	9,649,494	13,340,278	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		8,130,854	6,673,009	1,457,845	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	25,402,796	25,402,796	-	-	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ 358,419,620	$ 46,563,822	$ 311,855,798	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses													
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 12,501,304	1,358,608	11,142,696	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	10,051,562	10,051,562	-	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	48,391,532	-	48,391,532	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	12,209,687	-	12,209,687	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	3,446,376	-	3,446,376	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ 86,600,461	$ 11,410,170	$ 75,190,291	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ 445,020,081	$ 57,973,993	$ 387,046,088	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses													
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ -	-	-	-	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	10,609	10,609	-	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 10,609	$ 10,609	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses													
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 182,692	119,577	63,115	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	163,428	163,428	-	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	25,704	25,704	-	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	75,495	-	75,495	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	131,530	-	131,530	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ 578,849	$ 308,709	$ 270,140	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 589,458	$ 319,318	$ 270,140	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses (Continued)													
Other Power Generation Operation Expense													
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 647,260	647,260	-	-	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	107,114,208	-	107,114,208	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	682,059	682,059	-	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	5,376,587	5,376,587	-	-	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	9,693	9,693	-	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ 113,829,807	$ 6,715,599	$ 107,114,208	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense													
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 911,492	911,492	-	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	876,396	876,396	-	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	7,236,966	7,236,966	-	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	5,979,786	5,979,786	-	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ 15,004,640	$ 15,004,640	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ 128,834,447	$ 21,720,239	$ 107,114,208	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ 574,443,986	$ 80,013,549	$ 494,430,437	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses													
555 PURCHASED POWER	OM555	OMPP	$ 48,544,007	9,572,612	38,971,395	-	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP		-	-	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP		-	-	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP		-	-	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	2,300,266	2,300,266	-	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	154,987	154,987	-	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 50,999,260	$ 12,027,865	$ 38,971,395	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ 625,443,246	$ 92,041,415	$ 533,401,831	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses										
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
<u>Operation and Maintenance Expenses (Continued)</u>													
Transmission Expenses													
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 1,854,542	-	-	1,854,542	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	4,510,239	-	-	4,510,239	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	1,170,142	-	-	1,170,142	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	1,105,850	-	-	1,105,850	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	2,766,380	-	-	2,766,380	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	24,246,266	-	-	24,246,266	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	169,306	-	-	169,306	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,969,589	-	-	1,969,589	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	10,707,630	-	-	10,707,630	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	217,390	-	-	217,390	-	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-	-	-	-	-
Total Transmission Expenses			$ 48,717,334	$ -	$ -	$ 48,717,334	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense													
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 1,911,255	-	-	-	-	297,680	-	175,895	322,940	75,485	140,907
581 LOAD DISPATCHING	OM581	P362	438,256	-	-	-	-	438,256	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	2,231,084	-	-	-	-	2,231,084	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	6,598,429	-	-	-	-	-	-	1,676,097	2,978,435	699,997	1,243,900
584 UNDERGROUND LINE EXPENSES	OM584	P367	41,724	-	-	-	-	-	-	6,342	18,905	4,139	12,338
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	9,700,980	-	-	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	8,491,579	-	-	-	-	1,331,052	-	1,058,656	2,057,779	476,591	962,119
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 29,413,307	$ -	$ -	$ -	$ -	$ 4,298,072	$ -	$ 2,916,990	$ 5,378,059	$ 1,256,212	$ 2,359,263

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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Transmission Expenses										
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense										
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	37,666	31,294	26,385	772,788	30,216	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	9,700,980	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	694,743	577,211	486,662	289,437	557,329	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 732,409	$ 608,505	$ 513,047	$ 10,763,205	$ 587,545	$ -	$ -	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses (Continued)													
Distribution Maintenance Expense													
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 50,915	-	-	-	-	4,280	-	11,576	20,884	4,896	8,904
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	1,421,212	-	-	-	-	1,421,212	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	28,071,515	-	-	-	-	-	-	7,130,573	12,671,074	2,977,980	5,291,889
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	483,282	-	-	-	-	-	-	73,459	218,975	47,941	142,907
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	106,084	-	-	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	28	-	-	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	584,150	-	-	-	-	91,565	-	72,827	141,558	32,785	66,186
Total Distribution Maintenance Expense	OMDM		$ 30,717,186	$ -	$ -	$ -	$ -	$ 1,517,057	$ -	$ 7,288,435	$ 13,052,491	$ 3,063,602	$ 5,509,886
Total Distribution Operation and Maintenance Expenses			60,130,493	-	-	-	-	5,815,129	-	10,205,425	18,430,550	4,319,814	7,869,149
Transmission and Distribution Expenses			108,847,827	-	-	48,717,334	-	5,815,129	-	10,205,425	18,430,550	4,319,814	7,869,149
Production, Transmission and Distribution Expenses	OMSUB		$ 734,291,073	$ 92,041,415	$ 533,401,831	$ 48,717,334	$ -	$ 5,815,129	$ -	$ 10,205,425	$ 18,430,550	$ 4,319,814	$ 7,869,149
Customer Accounts Expense													
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 4,235,757	-	-	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	9,902,132	-	-	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	21,487,653	-	-	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	4,646,049	-	-	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	165,801	-	-	-	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 40,437,392	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense													
907 SUPERVISION	OM907	F026	$ 368,993	-	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	1,252,447	-	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	1,698,677	-	-	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	1,818,935	-	-	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	121,604	-	-	-	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 5,260,656	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		779,989,121	92,041,415	533,401,831	48,717,334	-	5,815,129	-	10,205,425	18,430,550	4,319,814	7,869,149

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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Distribution Maintenance Expense										
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	202	168	1	1	2	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	57,943	48,141	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	28	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	47,793	39,707	33,478	19,911	38,340	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 105,938	$ 88,016	$ 33,480	$ 19,940	$ 38,341	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			838,347	696,521	546,527	10,783,145	625,886	-	-	-
Transmission and Distribution Expenses			838,347	696,521	546,527	10,783,145	625,886	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 838,347	$ 696,521	$ 546,527	$ 10,783,145	$ 625,886	$ -	$ -	$ -
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	4,235,757	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	9,902,132	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	21,487,653	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	4,646,049	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	165,801	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ 40,437,392	$ -	$ -
Customer Service Expense										
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	368,993	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	1,252,447	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	1,698,677	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	1,818,935	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	121,604	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 5,260,656	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		838,347	696,521	546,527	10,783,145	625,886	40,437,392	5,260,656	-

KENTUCKY UTILITIES COMPANY
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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
				LOLP	Energy	Demand	Specific	General	Specific	Demand	Customer	Demand	Customer
Operation and Maintenance Expenses (Continued)													
Administrative and General Expense													
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 32,982,894	10,837,882	7,424,570	2,365,589	-	990,227	-	787,580	1,530,871	354,557	715,762
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	10,307,282	3,386,880	2,320,207	739,256	-	309,450	-	246,122	478,403	110,800	223,678
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(6,211,522)	(2,041,050)	(1,398,236)	(445,501)	-	(186,485)	-	(148,321)	(288,302)	(66,772)	(134,796)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	21,332,833	7,009,777	4,802,099	1,530,027	-	640,464	-	509,395	990,144	229,322	462,944
924 PROPERTY INSURANCE	OM924	TUP	8,726,372	5,439,383	-	1,243,596	-	320,301	-	254,753	495,179	114,686	231,522
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	4,777,652	1,569,893	1,075,467	342,661	-	143,437	-	114,083	221,750	51,358	103,680
926 EMPLOYEE BENEFITS	OM926	LBSUB7	31,473,418	10,341,882	7,084,781	2,257,327	-	944,909	-	751,536	1,460,810	338,330	683,004
928 REGULATORY COMMISSION FEES	OM928	TUP	851,305	530,641	-	121,320	-	31,247	-	24,852	48,307	11,188	22,586
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	3,314,333	1,089,060	746,068	237,710	-	99,504	-	79,141	153,832	35,628	71,924
931 RENTS AND LEASES	OM931	PGP	3,079,062	1,937,732	-	419,451	-	113,154	-	89,998	174,934	40,516	81,791
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	1,672,323	1,052,435	-	227,815	-	61,457	-	48,880	95,012	22,005	44,423
Total Administrative and General Expense	OMAG		$ 112,305,952	$ 41,154,516	$ 22,054,956	$ 9,039,250	$ -	$ 3,467,664	$ -	$ 2,758,018	$ 5,360,940	$ 1,241,618	$ 2,506,518
Total Operation and Maintenance Expenses	TOM		$ 892,295,073	$ 133,195,931	$ 555,456,787	$ 57,756,584	$ -	$ 9,282,793	$ -	$ 12,963,444	$ 23,791,490	$ 5,561,431	$ 10,375,667
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 843,751,066	$ 123,623,319	$ 516,485,392	$ 57,756,584	$ -	$ 9,282,793	$ -	$ 12,963,444	$ 23,791,490	$ 5,561,431	$ 10,375,667

KENTUCKY UTILITIES COMPANY
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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	516,849	429,412	362,049	215,325	414,621	5,393,575	644,026	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	161,517	134,193	113,142	67,290	129,571	1,685,513	201,261	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(97,336)	(80,869)	(68,183)	(40,551)	(78,084)	(1,015,748)	(121,287)	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	334,290	277,737	234,168	139,269	268,170	3,488,482	416,546	-
924 PROPERTY INSURANCE	OM924	TUP	167,181	138,899	117,109	69,649	134,114	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	74,867	62,201	52,444	31,190	60,059	781,272	93,289	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	493,195	409,760	345,480	205,470	395,646	5,146,736	614,552	-
928 REGULATORY COMMISSION FEES	OM928	TUP	16,309	13,550	11,425	6,795	13,084	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	51,936	43,150	36,381	21,637	41,664	541,981	64,716	-
931 RENTS AND LEASES	OM931	PGP	59,061	49,069	41,372	24,605	47,379	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	32,078	26,651	22,470	13,364	25,733	-	-	-
Total Administrative and General Expense	OMAG		$ 1,809,949	$ 1,503,754	$ 1,267,856	$ 754,043	$ 1,451,957	$ 16,021,811	$ 1,913,104	$ -
Total Operation and Maintenance Expenses	TOM		$ 2,648,296	$ 2,200,276	$ 1,814,383	$ 11,537,188	$ 2,077,842	$ 56,459,203	$ 7,173,760	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 2,648,296	$ 2,200,276	$ 1,814,383	$ 11,537,188	$ 2,077,842	$ 56,459,203	$ 7,173,760	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses													
Steam Power Generation Operation Expenses													
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 4,272,282	3,814,695	457,587	-	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	2,438,484	-	2,438,484	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	9,649,494	9,649,494	-	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	6,673,009	6,673,009	-	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	4,006,010	4,006,010	-	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 27,039,279	$ 24,143,208	$ 2,896,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses													
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 11,171,048	1,214,040	9,957,008	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	1,477,460	1,477,460	-	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	9,693,149	-	9,693,149	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	1,990,323	-	1,990,323	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	433,991	-	433,991	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 24,765,971	$ 2,691,500	$ 22,074,471	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ 51,805,250	$ 26,834,707	$ 24,970,543	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses													
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ -	-	-	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses													
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 160,360	104,960	55,400	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	43,386	43,386	-	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	911	911	-	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	22,712	-	22,712	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	669	-	669	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 228,038	$ 149,257	$ 78,781	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 228,038	$ 149,257	$ 78,781	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)													
Other Power Generation Operation Expense													
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 527,544	527,544	-	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	383,627	383,627	-	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	2,757,670	2,757,670	-	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 3,668,841	$ 3,668,841	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense													
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 732,436	732,436	-	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	351,927	351,927	-	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	1,277,077	1,277,077	-	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	1,287,143	1,287,143	-	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ 3,648,583	$ 3,648,583	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ 7,317,424	$ 7,317,424	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ 59,350,712	$ 34,301,388	$ 25,049,324	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power													
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ 2,263,912	2,263,912	-	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 2,263,912	$ 2,263,912	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)													
Transmission Labor Expenses													
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 1,591,418	-	-	1,591,418	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	4,089,959	-	-	4,089,959	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	424,026	-	-	424,026	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	45,989	-	-	45,989	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	393,950	-	-	393,950	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	1,126,679	-	-	1,126,679	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	309,102	-	-	309,102	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 7,981,123	$ -	$ -	$ 7,981,123	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense													
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ 1,268,655	-	-	-	-	197,594	-	116,756	214,361	50,105	93,531
581 LOAD DISPATCHING	LB581	P362	335,815	-	-	-	-	335,815	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	1,155,025	-	-	-	-	1,155,025	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	3,066,624	-	-	-	-	-	-	778,967	1,384,229	325,324	578,103
584 UNDERGROUND LINE EXPENSES	LB584	P367	28,983	-	-	-	-	-	-	4,405	13,132	2,875	8,570
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	5,005,004	-	-	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	3,043,460	-	-	-	-	477,061	-	379,432	737,527	170,815	344,832
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 13,903,566	$ -	$ -	$ -	$ -	$ 2,165,496	$ -	$ 1,279,560	$ 2,349,250	$ 549,119	$ 1,025,037

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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	25,002	20,772	17,514	512,962	20,057	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	5,005,004	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	249,002	206,878	174,424	103,737	199,752	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 274,004	$ 227,650	$ 191,938	$ 5,621,703	$ 219,809	$ -	$ -	$ -

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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)													
Distribution Maintenance Labor Expense													
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	622,340	-	-	-	-	622,340	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	6,481,662	-	-	-	-	-	-	1,646,436	2,925,728	687,610	1,221,888
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	248,892	-	-	-	-	-	-	37,832	112,773	24,690	73,598
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	53,407	-	-	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	3,541	-	-	-	-	555	-	441	858	199	401
Total Distribution Maintenance Labor Expense	LBDM		$ 7,409,842	$ -	$ -	$ -	$ -	$ 622,895	$ -	$ 1,684,710	$ 3,039,359	$ 712,499	$ 1,295,886
Total Distribution Operation and Maintenance Labor Expenses		PDIST	21,313,408	-	-	-	-	3,340,868	-	2,657,171	5,164,916	1,196,218	2,414,866
Transmission and Distribution Labor Expenses			29,294,531	-	-	7,981,123	-	3,340,868	-	2,657,171	5,164,916	1,196,218	2,414,866
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 90,909,155	$ 36,565,300	$ 25,049,324	$ 7,981,123	$ -	$ 3,340,868	$ -	$ 2,657,171	$ 5,164,916	$ 1,196,218	$ 2,414,866
Customer Accounts Expense													
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 4,005,700	-	-	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	752,362	-	-	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	13,439,006	-	-	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 18,197,068	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense													
907 SUPERVISION	LB907	F026	$ 350,160	-	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	1,306,105	-	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	516,578	-	-	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 2,172,843	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		111,279,066	36,565,300	25,049,324	7,981,123	-	3,340,868	-	2,657,171	5,164,916	1,196,218	2,414,866

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	29,171	24,236	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	290	241	203	121	232	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 29,461	$ 24,477	$ 203	$ 121	$ 232	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	1,743,767	1,448,769	1,221,497	726,471	1,398,865	-	-	-
Transmission and Distribution Labor Expenses			1,743,767	1,448,769	1,221,497	726,471	1,398,865	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 1,743,767	$ 1,448,769	$ 1,221,497	$ 726,471	$ 1,398,865	$ -	$ -	$ -
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	4,005,700	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	752,362	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	13,439,006	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ 18,197,068	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	350,160	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	1,306,105	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	516,578	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 2,172,843	$ -
Sub-Total Labor Exp	LBSUB7		1,743,767	1,448,769	1,221,497	726,471	1,398,865	18,197,068	2,172,843	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)													
Administrative and General Expense													
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$ 32,982,892	10,837,882	7,424,569	2,365,589	-	990,227	-	787,580	1,530,871	354,556	715,761
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	4,507	1,481	1,015	323	-	135	-	108	209	48	98
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(4,373,143)	(1,436,975)	(984,410)	(313,649)	-	(131,292)	-	(104,424)	(202,975)	(47,010)	(94,902)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	615,769	202,336	138,612	44,164	-	18,487	-	14,704	28,580	6,619	13,363
926 EMPLOYEE BENEFITS	LB926	LBSUB7	31,672,892	10,407,427	7,129,684	2,271,633	-	950,897	-	756,299	1,470,068	340,474	687,333
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	314,464	103,330	70,787	22,554	-	9,441	-	7,509	14,596	3,380	6,824
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	731,985	460,657	-	99,716	-	26,900	-	21,395	41,587	9,632	19,444
Total Administrative and General Expense	LBAG		$ 61,949,366	$ 20,576,137	$ 13,780,256	$ 4,490,330	$ -	$ 1,864,795	$ -	$ 1,483,171	$ 2,882,936	$ 667,701	$ 1,347,922
Total Operation and Maintenance Expenses	TLB		$ 173,228,432	$ 57,141,438	$ 38,829,580	$ 12,471,453	$ -	$ 5,205,663	$ -	$ 4,140,341	$ 8,047,851	$ 1,863,918	$ 3,762,788
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 173,228,432	$ 57,141,438	$ 38,829,580	$ 12,471,453	$ -	$ 5,205,663	$ -	$ 4,140,341	$ 8,047,851	$ 1,863,918	$ 3,762,788

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	516,849	429,412	362,049	215,325	414,621	5,393,574	644,026	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	71	59	49	29	57	737	88	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(68,528)	(56,935)	(48,003)	(28,550)	(54,974)	(715,124)	(85,390)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	9,649	8,017	6,759	4,020	7,741	100,695	12,024	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	496,321	412,357	347,669	206,772	398,153	5,179,355	618,447	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	4,928	4,094	3,452	2,053	3,953	51,423	6,140	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	14,041	11,665	9,835	5,849	11,263	-	-	-
Total Administrative and General Expense	LBAG		$ 973,330	$ 808,669	$ 681,811	$ 405,499	$ 780,814	$ 10,010,660	$ 1,195,335	$ -
Total Operation and Maintenance Expenses	TLB		$ 2,717,098	$ 2,257,438	$ 1,903,307	$ 1,131,971	$ 2,179,679	$ 28,207,728	$ 3,368,178	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 2,717,098	$ 2,257,438	$ 1,903,307	$ 1,131,971	$ 2,179,679	$ 28,207,728	$ 3,368,178	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Other Expenses													
Depreciation Expenses													
Steam Production	DEPRTP	PPRTL	$ 235,868,409	235,868,409	-	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	1,440,468	1,440,468	-	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	29,642,381	29,642,381	-	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	30,191,755	-	-	30,191,755	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	192,228	-	-	192,228	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP5	PTRAN	20,672	-	-	20,672	-	-	-	-	-	-	-
Distribution	DEPRDP6	PDIST	38,870,091	-	-	-	-	6,092,871	-	4,845,985	9,419,458	2,181,589	4,404,085
General Plant	DEPRDP7	PGP	13,809,821	8,690,872	-	1,881,267	-	507,505	-	403,646	784,593	181,715	366,838
Intangible Plant	DEPRDP8	PINT	20,495,320	12,898,226	-	2,792,011	-	753,195	-	599,056	1,164,424	269,686	544,429
Total Depreciation Expense	TDEPR		$ 370,531,145	288,540,356	-	35,077,933	-	7,353,572	-	5,848,688	11,368,475	2,632,990	5,315,352
Regulatory Credits and Accretion Expenses													
Production Plant	ACRTPP	PPRTL	$ -	-	-	-	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	$ 35,914,758	22,386,637	-	5,118,215	-	1,318,249	-	1,048,474	2,037,987	472,007	952,865
Other Taxes	OTAX	TUP	$ 13,649,179	8,507,901	-	1,945,146	-	500,992	-	398,466	774,524	179,383	362,130
Gain Disposition of Allowances	GAIN	F013	$ -	-	-	-	-	-	-	-	-	-	-
Interest	INTLTD	TUP	$ 109,640,429	68,341,836	-	15,624,866	-	4,024,346	-	3,200,777	6,221,559	1,440,941	2,908,902
Other Expenses	OT	TUP	$ -	-	-	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 529,735,511	$ 387,776,730	$ -	$ 57,766,160	$ -	$ 13,197,160	$ -	$ 10,496,405	$ 20,402,546	$ 4,725,321	$ 9,539,249
Total Cost of Service (O&M + Other Expenses)			$ 1,422,030,584	$ 520,972,662	$ 555,456,787	$ 115,522,743	$ -	$ 22,479,953	$ -	$ 23,459,849	$ 44,194,036	$ 10,286,752	$ 19,914,916

KENTUCKY UTILITIES COMPANY
Cost of Service Study
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LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP5	PTRAN	-	-	-	-	-	-	-	-
Distribution	DEPRDP6	PDIST	3,180,176	2,642,176	2,227,691	1,324,894	2,551,165	-	-	-
General Plant	DEPRDP7	PGP	264,893	220,080	185,555	110,357	212,499	-	-	-
Intangible Plant	DEPRDP8	PINT	393,130	326,623	275,385	163,782	315,373	-	-	-
Total Depreciation Expense	TDEPR		3,838,199	3,188,880	2,688,631	1,599,033	3,079,037	-	-	-
Regulatory Credits and Accretion Expenses										
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	688,061	571,659	481,982	286,653	551,968	-	-	-
Other Taxes	OTAX	TUP	261,493	217,256	183,174	108,941	209,772	-	-	-
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-	-
Interest	INTLTD	TUP	2,100,509	1,745,160	1,471,391	875,094	1,685,047	-	-	-
Other Expenses	OT	TUP	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 6,888,262	$ 5,722,954	$ 4,825,178	$ 2,869,721	$ 5,525,824	$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 9,536,558	$ 7,923,230	$ 6,639,561	$ 14,406,908	$ 7,603,667	$ 56,459,203	$ 7,173,760	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Functional Vectors													
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.254015	0.451385	0.106085	0.188515
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.254015	0.451385	0.106085	0.188515
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.152001	0.453099	0.099199	0.295701
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		22,766,997	20,328,513	2,438,484	-	-	-	-	-	-	-	-
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		13,594,923	1,477,460	12,117,463	-	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		67,678	44,297	23,381	-	-	-	-	-	-	-	-
Distribution Operation Labor	F023		12,634,911	-	-	-	-	1,967,901	-	1,162,805	2,134,889	499,014	931,506
Distribution Maintenance Labor	F024		7,409,842	-	-	-	-	622,895	-	1,684,710	3,039,359	712,499	1,295,886
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		1,169,477,392	-	-	-	-	-	-	271,796,970	528,309,481	122,358,838	247,012,103
Purchase Power Demand		F017	9,604,907	9,604,907	-	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	39,102,871	-	39,102,871	-	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	48,707,778	9,604,907	39,102,871	-	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		1.00000	-	1.000000	-	-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors													
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.629325	-	0.136227	-	0.036750	-	0.029229	0.056814	0.013158	0.026564
Total Distribution Plant		PDIST	1.000000	-	-	-	-	0.156750	-	0.124671	0.242332	0.056125	0.113303
Total Transmission Plant		PTRAN	1.000000	-	-	1.000000	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.146516	0.612130	0.068452	-	0.011002	-	0.015364	0.028197	0.006591	0.012297
Total Plant in Service		TPIS	1.000000	0.629277	-	0.136210	-	0.036760	-	0.029237	0.056830	0.013162	0.026571
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.329862	0.224152	0.071994	-	0.030051	-	0.023901	0.046458	0.010760	0.021722
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.118003	0.683858	0.062459	-	0.007455	-	0.013084	0.023629	0.005538	0.010089
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.892894	0.107106	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.108677	0.891323	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.654526	0.345474	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	1.000000	-	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	1.0000000	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	-	0.155751	-	0.092031	0.168967	0.039495	0.073725
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	-	0.084063	-	0.227361	0.410179	0.096156	0.174887
Sub-Total Labor Exp		LBSUB7	1.000000	0.328591	0.225104	0.071722	-	0.030022	-	0.023878	0.046414	0.010750	0.021701
Total General Plant		PGP	1.000000	0.629325	-	0.136227	-	0.036750	-	0.029229	0.056814	0.013158	0.026564
Total Production Plant		PPRTL	1.000000	1.000000	-	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	1.000000	0.629325	-	0.136227	-	0.036750	-	0.029229	0.056814	0.013158	0.026564

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2022

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Functional Vectors										
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.546201	0.453799	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-	-
Distribution Operation Labor	F023		249,002	206,878	174,424	5,108,741	199,752	-	-	-
Distribution Maintenance Labor	F024		29,461	24,477	203	121	232	-	-	-
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors										
Total Prod, Trans, and Dist Plant		PT&D	0.019181	0.015936	0.013436	0.007991	0.015388	-	-	-
Total Distribution Plant		PDIST	0.081816	0.067975	0.057311	0.034085	0.065633	-	-	-
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.003139	0.002608	0.002150	0.013674	0.002463	0.066915	0.008502	-
Total Plant in Service		TPIS	0.019187	0.015941	0.013440	0.007993	0.015392	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.015685	0.013032	0.010987	0.006535	0.012583	0.162835	0.019444	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.001075	0.000893	0.000701	0.013825	0.000802	0.051844	0.006745	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.019707	0.016374	0.013805	0.404335	0.015810	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	0.003976	0.003303	0.000027	0.000016	0.000031	-	-	-
Sub-Total Labor Exp		LBSUB7	0.015670	0.013019	0.010977	0.006528	0.012571	0.163526	0.019526	-
Total General Plant		PGP	0.019181	0.015936	0.013436	0.007991	0.015388	-	-	-
Total Production Plant		PPRTL	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.019181	0.015936	0.013436	0.007991	0.015388	-	-	-

Exhibit WSS-30

Electric Cost of Service Study
Functional Assignment and
Classification
(Louisville Gas and Electric Company)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Plant in Service												
Intangible Plant												
301.00 ORGANIZATION	P301	PT&D	$ 2,240	1,368	-	210	83	-	127	208	35	60
302.00 FRANCHISE AND CONSENTS	P301	PT&D	-	-	-	-	-	-	-	-	-	-
303.00 SOFTWARE - COMMON	P302	PT&D	-	-	-	-	-	-	-	-	-	-
301.00 ORGANIZATION - COMMON	P301	PT&D	-	-	-	-	-	-	-	-	-	-
302.00 FRANCHISE AND CONSENTS - COMMON	P301	PT&D	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant	PINT		$ 2,240	$ 1,368	$ -	$ 210	$ 83	$ -	$ 127	$ 208	$ 35	$ 60
Steam Production Plant												
Total Steam Production Plant	PSTPR	F017	$ 3,109,195,352	3,109,195,352	-	-	-	-	-	-	-	-
Hydraulic Production Plant												
Total Hydraulic Production Plant	PHDPR	F017	$ 159,587,945	159,587,945	-	-	-	-	-	-	-	-
Other Production Plant												
Total Other Production Plant	POTPR	F017	$ 418,289,975	418,289,975	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ 3,687,073,272	$ 3,687,073,272	$ -	$ -		$ -	$ -			
Transmission												
Total Transmission Plant	PTRAN	F011	$ 566,296,585	-	-	566,296,585	-	-	-	-	-	-
Total Transmission Plant	PTRTL		$ 566,296,585	$ -	$ -	$ 566,296,585	$ -	$ -	$ -	$ -	$ -	$ -
Distribution												
TOTAL ACCTS 360-362	P362	F001	$ 222,802,329	-	-	-	222,802,329	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	684,235,593	-	-	-	-	-	173,756,511	308,766,430	72,636,726	129,075,927
366 & 367-UNDERGROUND LINES	P367	F004	476,035,911	-	-	-	-	-	168,284,874	250,959,953	22,795,941	33,995,143
368-TRANSFORMERS	P368	F005	182,077,170	-	-	-	-	-	-	-	-	-
369-SERVICES	P369	F006	41,665,746	-	-	-	-	-	-	-	-	-
370-METERS	P370	F007	42,308,485	-	-	-	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F007	183,388	-	-	-	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	137,373,834	-	-	-	-	-	-	-	-	-
374-ASSET RETIRE OBLIGATIONS DIST PLANT	P374	F003	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 1,786,682,455	$ -	$ -	$ -	$ 222,802,329	$ -	$ 342,041,384	$ 559,726,383	$ 95,432,668	$ 163,071,070
Total Prod, Trans, and Dist Plant	PT&D		$ 6,040,052,312	$ 3,687,073,272	$ -	$ 566,296,585	$ 222,802,329	$ -	$ 342,041,384	$ 559,726,383	$ 95,432,668	$ 163,071,070

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service										
Intangible Plant										
301.00 ORGANIZATION	P301	PT&D	43	24	15	16	51	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	-	-	-	-	-	-	-	-
303.00 SOFTWARE - COMMON	P302	PT&D	-	-	-	-	-	-	-	-
301.00 ORGANIZATION - COMMON	P301	PT&D	-	-	-	-	-	-	-	-
302.00 FRANCHISE AND CONSENTS - COMMON	P301	PT&D	-	-	-	-	-	-	-	-
Total Intangible Plant	PINT		$ 43	$ 24	$ 15	$ 16	$ 51	$ -	$ -	$ -
Steam Production Plant										
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-	-
Hydraulic Production Plant										
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-	-
Other Production Plant										
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -			$ -	$ -	$ -	$ -
Transmission										
Total Transmission Plant	PTRAN	F011	-	-	-	-	-	-	-	-
Total Transmission Plant	PTRTL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution										
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	-	-	-	-
368-TRANSFORMERS	P368	F005	116,910,393	65,166,777	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	41,665,746	-	-	-	-	-
370-METERS	P370	F007	-	-	-	42,308,485	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F007	-	-	-	183,388	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	137,373,834	-	-	-
374-ASSET RETIRE OBLIGATIONS DIST PLANT	P374	F003	-	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 116,910,393	$ 65,166,777	$ 41,665,746	$ 42,491,872	$ 137,373,834	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 116,910,393	$ 65,166,777	$ 41,665,746	$ 42,491,872	$ 137,373,834	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
				LOLP	Energy	Demand	General	Specific	Demand	Customer	Demand	Customer
Plant in Service (Continued)												
General Plant												
Total General Plant	PGP	PT&D	$ 21,026,365	12,835,277	-	1,971,367	775,610	-	1,190,699	1,948,495	332,216	567,676
TOTAL COMMON PLANT	PCOM	PT&D	$ 231,173,767	141,117,092	-	21,674,136	8,527,418	-	13,091,111	21,422,671	3,652,539	6,241,296
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DIST	P105	PDIST	2,908,740	-	-	-	362,725	-	556,847	911,241	155,366	265,482
105.00 PLANT HELD FOR FUTURE USE - PROD	P105	F017	211,410	211,410	-	-	-	-	-	-	-	-
PROPERTY HELD UNDER CAPITAL LEASE		F017	-	-	-	-	-	-	-	-	-	-
OTHER		PDIST	$ -	-	-	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 6,295,374,834	$ 3,841,238,419	$ -	$ 589,942,298	$ 232,468,164	$ -	$ 356,880,169	$ 584,008,998	$ 99,572,824	$ 170,145,583
Construction Work in Progress (CWIP)												
CWIP Production	CWIP1	F017	$ 17,402,861	17,402,861	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	21,580,855	-	-	21,580,855	-	-	-	-	-	-
CWIP Distribution	CWIP3	PDIST	16,836,832	-	-	-	2,099,581	-	3,223,233	5,274,591	899,311	1,536,703
CWIP General & Common	CWIP4	PT&D	11,356,326	6,932,325	-	1,064,734	418,906	-	643,096	1,052,381	179,430	306,601
Total Construction Work in Progress	TCWIP		$ 67,176,874	$ 24,335,186	$ -	$ 22,645,589	$ 2,518,488	$ -	$ 3,866,329	$ 6,326,972	$ 1,078,741	$ 1,843,304
Total Utility Plant			$ 6,362,551,708	$ 3,865,573,604	$ -	$ 612,587,887	$ 234,986,652	$ -	$ 360,746,498	$ 590,335,970	$ 100,651,565	$ 171,988,888

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)										
General Plant										
Total General Plant	PGP	PT&D	406,983	226,856	145,045	147,921	478,220	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	4,474,567	2,494,159	1,594,693	1,626,311	5,257,773	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DIST	P105	PDIST	190,331	106,092	67,832	69,177	223,646	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PROD	P105	F017	-	-	-	-	-	-	-	-
PROPERTY HELD UNDER CAPITAL LEASE		F017	-	-	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 121,982,317	$ 67,993,908	$ 43,473,331	$ 44,335,297	$ 143,333,524	$ -	$ -	$ -
Construction Work in Progress (CWIP)										
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-	-
CWIP Distribution	CWIP3	PDIST	1,101,707	614,100	392,638	400,423	1,294,545	-	-	-
CWIP General & Common	CWIP4	PT&D	219,811	122,525	78,339	79,892	258,286	-	-	-
Total Construction Work in Progress	TCWIP		$ 1,321,518	$ 736,625	$ 470,977	$ 480,315	$ 1,552,831	$ -	$ -	$ -
Total Utility Plant			$ 123,303,836	$ 68,730,533	$ 43,944,308	$ 44,815,612	$ 144,886,355	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Rate Base												
Utility Plant												
Plant in Service			$ 6,295,374,834	$ 3,841,238,419	$ -	$ 589,942,298	$ 232,468,164	$ -	$ 356,880,169	$ 584,008,998	$ 99,572,824	$ 170,145,583
Construction Work in Progress (CWIP)			67,176,874	24,335,185.61	-	22,645,588.93	2,518,487.76	-	3,866,328.71	6,326,971.77	1,078,740.99	1,843,304.31
Total Utility Plant	TUP		$ 6,362,551,708	$ 3,865,573,604	$ -	$ 612,587,887	$ 234,986,652	$ -	$ 360,746,498	$ 590,335,970	$ 100,651,565	$ 171,988,888
Less: Accumulated Provision for Depreciation and RWIP												
Production	ADEPREPA	F017	$ 1,306,343,857	1,306,343,857	-	-	-	-	-	-	-	-
Transmission	ADEPRTP	PTRAN	180,532,195	-	-	180,532,195	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	585,717,151	-	-	-	73,039,921	-	112,129,329	183,491,667	31,285,106	53,458,589
General & Common Plant	ADEPRD12	PT&D	104,591,141	63,846,335	-	9,806,141	3,858,104	-	5,922,879	9,692,370	1,652,537	2,823,782
Intangible Plant	ADEPRGP	PT&D	-	-	-	-	-	-	-	-	-	-
RWIP	RWIP	PT&D	-	-	-	-	-	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 2,177,184,344	$ 1,370,190,192	$ -	$ 190,338,336	$ 76,898,025	$ -	$ 118,052,208	$ 193,184,037	$ 32,937,643	$ 56,282,370
Net Utility Plant	NTPLANT		$ 4,185,367,364	$ 2,495,383,413	$ -	$ 422,249,551	$ 158,088,627	$ -	$ 242,694,290	$ 397,151,933	$ 67,713,921	$ 115,706,517
Working Capital												
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 124,454,261	18,304,703	78,365,699	7,147,160	1,674,372	-	2,737,300	4,581,334	864,546	1,497,986
Materials and Supplies	M&S	TPIS	44,127,133	26,924,979	-	4,135,173	1,629,475	-	2,501,535	4,093,584	697,951	1,192,627
Prepayments	PREPAY	TPIS	14,687,906	8,962,095	-	1,376,410	542,378	-	832,647	1,362,567	232,316	396,971
Fuel Stock		F017	33,196,476	33,196,476	-	-	-	-	-	-	-	-
Total Working Capital	TWC		$ 216,465,777	$ 87,388,254	$ 78,365,699	$ 12,658,743	$ 3,846,224	$ -	$ 6,071,481	$ 10,037,485	$ 1,794,813	$ 3,087,585
Deferred Debits												
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	$ 2,369,448	-	-	-	-	-	698,500	1,143,045	194,888	333,016
Accumulated Deferred Income Taxes												
Accumulated Deferred Income Taxes	DIT	TPIS	$ 939,385,876	573,183,522	-	88,030,257	34,688,532	-	53,253,094	87,144,899	14,858,099	25,388,855
FAS 109 Deferred Income Taxes	DIT	TPIS	$ -	-	-	-	-	-	-	-	-	-
Asset Retirement Obligation-Net Assets	DIT	TPIS	$ -	-	-	-	-	-	-	-	-	-
Asset Retirement Obligation-Regulatory Liabilities	DIT	TPIS	$ -	-	-	-	-	-	-	-	-	-
Total Accumulated Deferred Income Tax			$ 939,385,876	$ 573,183,522	$ -	$ 88,030,257	$ 34,688,532	$ -	$ 53,253,094	$ 87,144,899	$ 14,858,099	$ 25,388,855
Investment Tax Credits												
Total Production Plant	DIT	F017	$ -	-	-	-	-	-	-	-	-	-
Total Transmission Plant	DIT	PTRAN	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant	DIT	PDIST	-	-	-	-	-	-	-	-	-	-
Total General Plant	DIT	PT&D	-	-	-	-	-	-	-	-	-	-
Total Investment Tax Credit			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Rate Base	RB		$ 3,460,077,816	$ 2,009,588,145	$ 78,365,699	$ 346,878,037	$ 127,246,319	$ -	$ 194,814,177	$ 318,901,474	$ 54,455,747	$ 93,072,232

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base										
Utility Plant										
Plant in Service			$ 121,982,317	$ 67,993,908	$ 43,473,331	$ 44,335,297	$ 143,333,524	$ -	$ -	$ -
Construction Work in Progress (CWIP)			1,321,518.47	736,624.84	470,976.54	480,314.82	1,552,830.80	-	-	-
Total Utility Plant	TUP		$ 123,303,836	$ 68,730,533	$ 43,944,308	$ 44,815,612	$ 144,886,355	$ -	$ -	$ -
Less: Accumulated Provision for Depreciation and RWIP										
Production	ADEPREPA	F017	-	-	-	-	-	-	-	-
Transmission	ADEPRTP	PTRAN	-	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	38,326,017	21,363,225	13,659,026	13,929,850	45,034,421	-	-	-
General & Common Plant	ADEPRD12	PT&D	2,024,451	1,128,445	721,495	735,800	2,378,802	-	-	-
Intangible Plant	ADEPRGP	PT&D	-	-	-	-	-	-	-	-
RWIP	RWIP	PT&D	-	-	-	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 40,350,468	$ 22,491,670	$ 14,380,521	$ 14,665,650	$ 47,413,223	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 82,953,368	$ 46,238,863	$ 29,563,787	$ 30,149,962	$ 97,473,132	$ -	$ -	$ -
Working Capital										
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	231,637	129,116	69,036	2,886,220	347,121	4,604,270	1,013,761	-
Materials and Supplies	M&S	TPIS	855,029	476,600	304,724	310,766	1,004,690	-	-	-
Prepayments	PREPAY	TPIS	284,600	158,638	101,429	103,440	334,415	-	-	-
Fuel Stock		F017	-	-	-	-	-	-	-	-
Total Working Capital	TWC		$ 1,371,266	$ 764,355	$ 475,189	$ 3,300,426	$ 1,686,226	$ 4,604,270	$ 1,013,761	$ -
Deferred Debits										
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-	-	-	-	-	-
Accumulated Deferred Income Taxes										
Accumulated Deferred Income Taxes	DIT	TPIS	18,202,008	10,145,943	6,487,022	6,615,643	21,388,002	-	-	-
FAS 109 Deferred Income Taxes	DIT	TPIS	-	-	-	-	-	-	-	-
Asset Retirement Obligation-Net Assets	DIT	TPIS	-	-	-	-	-	-	-	-
Asset Retirement Obligation-Regulatory Liabilities	DIT	TPIS	-	-	-	-	-	-	-	-
Total Accumulated Deferred Income Tax			$ 18,202,008	$ 10,145,943	$ 6,487,022	$ 6,615,643	$ 21,388,002	$ -	$ -	$ -
Investment Tax Credits										
Total Production Plant	DIT	F017	-	-	-	-	-	-	-	-
Total Transmission Plant	DIT	PTRAN	-	-	-	-	-	-	-	-
Total Distribution Plant	DIT	PDIST	-	-	-	-	-	-	-	-
Total General Plant	DIT	PT&D	-	-	-	-	-	-	-	-
Total Investment Tax Credit			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Rate Base	RB		$ 66,122,625	$ 36,857,274	$ 23,551,954	$ 26,834,745	$ 77,771,357	$ 4,604,270	$ 1,013,761	$ -

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 5,359,919	4,681,925	677,994	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	254,165,772	-	254,165,772	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502	PROFIX	18,685,164	18,685,164	-	-	-	-	-	-	-	-
504 STEAM TRANSFER EXPENSES	OM504	PROFIX	-	-	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	2,353,024	2,353,024	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	16,437,786	16,437,786	-	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ 297,001,665	$ 42,157,899	$ 254,843,766	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 8,141,536	31,953	8,109,583	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	3,444,669	3,444,669	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	34,342,497	-	34,342,497	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	14,018,415	-	14,018,415	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	1,551,793	-	1,551,793	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ 61,498,910	$ 3,476,622	$ 58,022,288	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ 358,500,575	$ 45,634,521	$ 312,866,054	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses												
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ 116,778	116,778	-	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	43,212	43,212	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	324,155	324,155	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	213,613	213,613	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	568,902	568,902	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 1,266,660	$ 1,266,660	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses												
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ -	-	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	323,993	323,993	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	222,489	222,489	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	327,894	-	327,894	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	56,196	-	56,196	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ 930,572	$ 546,482	$ 384,090	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 2,197,232	$ 1,813,142	$ 384,090	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 187,484	187,484	-	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	43,921,446	-	43,921,446	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	300,829	300,829	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	1,742,424	1,742,424	-	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	11,652	11,652	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ 46,163,835	$ 2,242,389	$ 43,921,446	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502	PROFIX	-	-	-	-	-	-	-	-
504 STEAM TRANSFER EXPENSES	OM504	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

12 Months Ended
June 30, 2022

				Production Demand	Production Energy	Transmission Demand	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
Description	Name	Functional Vector	Total System	LOLP	Energy	Demand	General	Specific	Demand	Customer	Demand	Customer
Operation and Maintenance Expenses (Continued)												
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 272,764	272,764	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	235,911	235,911	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	3,098,761	3,098,761	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	1,896,209	1,896,209	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ 5,503,645	$ 5,503,645	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ 51,667,480	$ 7,746,034	$ 43,921,446	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ 412,365,288	$ 55,193,697	$ 357,171,590	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses												
555 PURCHASED POWER	OM555	OMPP	$ 43,276,671	23,686,711	19,589,961	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	1,775,597	1,775,597	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	122,949	122,949	-	-	-	-	-	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 45,175,217	$ 25,585,257	$ 19,589,961	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ 457,540,505	$ 80,778,954	$ 376,761,551	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses												
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 1,374,229	-	-	1,374,229	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	2,719,716	-	-	2,719,716	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	1,022,714	-	-	1,022,714	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	293,742	-	-	293,742	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	11,844	-	-	11,844	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	12,977,686	-	-	12,977,686	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	61,385	-	-	61,385	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,720,071	-	-	1,720,071	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	7,356,001	-	-	7,356,001	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	236,185	-	-	236,185	-	-	-	-	-	-
575 MISO DAY 1 & 2 EXPENSES	OM575	LBTRAN	-	-	-	-	-	-	-	-	-	-
Total Transmission Expenses			$ 27,773,573	$ -	$ -	$ 27,773,573	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses										
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses										
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-	-
575 MISO DAY 1 & 2 EXPENSES	OM575	LBTRAN	-	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses (Continued)												
Distribution Operation Expense												
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 2,397,039	-	-	-	355,547	-	283,565	481,036	95,932	167,375
581 LOAD DISPATCHING	OM581	P362	292,953	-	-	-	292,953	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	1,764,640	-	-	-	1,764,640	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	5,783,700	-	-	-	-	-	1,468,727	2,609,938	613,983	1,091,052
584 UNDERGROUND LINE EXPENSES	OM584	P367	6,320,821	-	-	-	-	-	2,234,492	3,332,255	302,685	451,389
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	7,932,375	-	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	7,395,817	-	-	-	922,271	-	1,415,851	2,316,939	395,035	675,019
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	35,725	-	-	-	4,455	-	6,839	11,192	1,908	3,261
Total Distribution Operation Expense	OMDO		$ 31,923,070	$ -	$ -	$ -	$ 3,339,866	$ -	$ 5,409,474	$ 8,751,359	$ 1,409,543	$ 2,388,094
Distribution Maintenance Expense												
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 47,090	-	-	-	6,498	-	11,032	18,519	3,538	6,141
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	1,865,977	-	-	-	1,865,977	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	15,769,154	-	-	-	-	-	4,004,459	7,115,949	1,674,014	2,974,733
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	1,854,313	-	-	-	-	-	655,524	977,570	88,798	132,422
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	185,535	-	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	568,134	-	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	870,332	-	-	-	108,532	-	166,616	272,655	46,487	79,435
Total Distribution Maintenance Expense	OMDM		$ 21,160,535	$ -	$ -	$ -	$ 1,981,006	$ -	$ 4,837,630	$ 8,384,692	$ 1,812,837	$ 3,192,731
Total Distribution Operation and Maintenance Expenses			$ 53,083,605	-	-	-	5,320,872	-	10,247,105	17,136,051	3,222,380	5,580,825
Transmission and Distribution Expenses			$ 80,857,178	-	-	27,773,573	5,320,872	-	10,247,105	17,136,051	3,222,380	5,580,825
Production, Transmission and Distribution Expenses	OMSUB		$ 538,397,683	$ 80,778,954	$ 376,761,551	$ 27,773,573	$ 5,320,872	$ -	$ 10,247,105	$ 17,136,051	$ 3,222,380	$ 5,580,825

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Distribution Operation Expense										
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	28,597	15,940	10,192	925,254	33,602	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	7,932,375	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	483,940	269,752	172,472	175,891	568,647	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	2,338	1,303	833	850	2,747	-	-	-
Total Distribution Operation Expense	OMDO		$ 514,875	$ 286,995	$ 183,497	$ 9,034,370	$ 604,996	$ -	$ -	$ -
Distribution Maintenance Expense										
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	808	451	-	-	104	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	119,131	66,404	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	568,134	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	56,950	31,744	20,296	20,699	66,918	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 176,889	$ 98,599	$ 20,296	$ 20,699	$ 635,155	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			691,764	385,595	203,793	9,055,069	1,240,152	-	-	-
Transmission and Distribution Expenses			691,764	385,595	203,793	9,055,069	1,240,152	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 691,764	$ 385,595	$ 203,793	$ 9,055,069	$ 1,240,152	$ -	$ -	$ -

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses (Continued)												
Customer Accounts Expense												
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 1,498,909	-	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	3,820,562	-	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	7,929,806	-	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	2,225,668	-	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 15,474,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense												
907 SUPERVISION	OM907	F026	$ 199,518	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	821,366	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026		-	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	1,201,025	-	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026		-	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	1,144,803	-	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	56,160	-	-	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 3,422,872	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		557,295,500	80,778,954	376,761,551	27,773,573	5,320,872	-	10,247,105	17,136,051	3,222,380	5,580,825

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	1,498,909	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	3,820,562	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	7,929,806	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	2,225,668	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ 15,474,945	$ -	$ -
Customer Service Expense										
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	199,518	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	821,366	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	1,201,025	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	1,144,803	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	56,160	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 3,422,872	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		691,764	385,595	203,793	9,055,069	1,240,152	15,474,945	3,422,872	-

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 25,891,027	8,431,182	7,150,540	1,943,054	808,693	-	802,104	1,355,414	266,150	463,477
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	7,802,685	2,540,875	2,154,932	585,571	243,713	-	241,727	408,476	80,209	139,676
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(5,240,118)	(1,706,398)	(1,447,207)	(393,257)	(163,672)	-	(162,339)	(274,324)	(53,866)	(93,804)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	17,066,021	5,557,397	4,713,264	1,280,760	533,049	-	528,706	893,419	175,432	305,500
924 PROPERTY INSURANCE	OM924	TUP	7,218,578	4,385,653	-	695,006	266,602	-	409,282	669,761	114,193	195,128
925 INJURIES AND DAMAGES	OM925	LBSUB7	3,235,548	1,053,627	893,588	242,819	101,061	-	100,237	169,383	33,260	57,920
926 EMPLOYEE BENEFITS	OM926	LBSUB7	23,981,335	7,809,308	6,623,124	1,799,737	749,045	-	742,942	1,255,440	246,519	429,291
927 FRANCHISE REQUIREMENTS	OM927	TUP	-	-	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	984,809	598,322	-	94,818	36,372	-	55,837	91,373	15,579	26,621
929 DUPLICATE CHARGES-CR	OM929	LBSUB7	(216,193)	(70,401)	(59,708)	(16,225)	(6,753)	-	(6,698)	(11,318)	(2,222)	(3,870)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	2,554,270	831,775	705,434	191,691	79,781	-	79,131	133,718	26,257	45,724
931 RENTS AND LEASES	OM931	PGP	1,807,941	1,103,635	-	169,507	66,690	-	102,382	167,540	28,565	48,811
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	1,055,259	644,170	-	98,938	38,926	-	59,758	97,790	16,673	28,490
Total Administrative and General Expense	OMAG		$ 86,141,161	$ 31,179,144	$ 20,733,968	$ 6,692,420	$ 2,753,507	$ -	$ 2,953,070	$ 4,956,673	$ 946,748	$ 1,642,966
Total Operation and Maintenance Expenses	TOM		$ 643,436,661	$ 111,958,098	$ 397,495,519	$ 34,465,993	$ 8,074,379	$ -	$ 13,200,175	$ 22,092,724	$ 4,169,129	$ 7,223,791
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 600,159,990	$ 88,271,387	$ 377,905,558	$ 34,465,993	$ 8,074,379	$ -	$ 13,200,175	$ 22,092,724	$ 4,169,129	$ 7,223,791

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	72,722	40,536	18,178	1,650,318	62,718	2,320,423	505,519	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	21,916	12,216	5,478	497,350	18,901	699,297	152,346	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(14,718)	(8,204)	(3,679)	(334,010)	(12,694)	(469,633)	(102,313)	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	47,935	26,719	11,982	1,087,804	41,340	1,529,502	333,212	-
924 PROPERTY INSURANCE	OM924	TUP	139,893	77,978	49,857	50,845	164,380	-	-	-
925 INJURIES AND DAMAGES	OM925	LBSUB7	9,088	5,066	2,272	206,237	7,838	289,978	63,174	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	67,358	37,546	16,837	1,528,592	58,092	2,149,271	468,232	-
927 FRANCHISE REQUIREMENTS	OM927	TUP	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	19,085	10,638	6,802	6,937	22,426	-	-	-
929 DUPLICATE CHARGES-CR	OM929	LBSUB7	(607)	(338)	(152)	(13,780)	(524)	(19,376)	(4,221)	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	7,174	3,999	1,793	162,811	6,187	228,920	49,872	-
931 RENTS AND LEASES	OM931	PGP	34,994	19,506	12,472	12,719	41,119	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	20,425	11,385	7,279	7,424	24,001	-	-	-
Total Administrative and General Expense	OMAG		$ 425,266	$ 237,046	$ 129,120	$ 4,863,247	$ 433,784	$ 6,728,383	$ 1,465,821	$ -
Total Operation and Maintenance Expenses	TOM		$ 1,117,029	$ 622,641	$ 332,913	$ 13,918,315	$ 1,673,935	$ 22,203,328	$ 4,888,693	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 1,117,029	$ 622,641	$ 332,913	$ 13,918,315	$ 1,673,935	$ 22,203,328	$ 4,888,693	$ -
						$ 70,751,095				

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
				LOLP	Energy	Demand	General	Specific	Demand	Customer	Demand	Customer
Labor Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 3,778,998	3,300,980	478,018	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	1,594,068	-	1,594,068	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	6,850,162	6,850,162	-	-	-	-	-	-	-	-
504 STEAM TRANSFER EXPENSES	LB504	PROFIX	-	-	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	1,917,383	1,917,383	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	2,240,372	2,240,372	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 16,380,983	$ 14,308,897	$ 2,072,086	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 5,516,682	21,652	5,495,030	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	30,396	30,396	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	4,426,057	-	4,426,057	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	3,169,334	-	3,169,334	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	118,915	-	118,915	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 13,261,384	$ 52,048	$ 13,209,336	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ 29,642,367	$ 14,360,944	$ 15,281,423	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses												
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ 93,014	93,014	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	262,377	262,377	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ 355,391	$ 355,391	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses												
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ -	-	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	50,196	50,196	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	35,849	35,849	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	72,238	-	72,238	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 158,283	$ 86,045	$ 72,238	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 513,674	$ 441,436	$ 72,238	$ -	$ -	$ -	$ -	$ -	$ -	$ -

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-	-
504 STEAM TRANSFER EXPENSES	LB504	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
June 30, 2022

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 115,734	115,734	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	166,747	166,747	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	746,366	746,366	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 1,028,847	$ 1,028,847	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 171,475	171,475	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	82,367	82,367	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	361,575	361,575	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	305,811	305,811	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ 921,228	$ 921,228	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ 1,950,075	$ 1,950,075	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ 32,106,116	$ 16,752,455	$ 15,353,661	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power												
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	1,351,005	1,351,005	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 1,351,005	$ 1,351,005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
				LOLP	Energy	Demand	General	Specific	Demand	Customer	Demand	Customer
Labor Expenses (Continued)												
Transmission Labor Expenses												
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 884,644	-	-	884,644	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	1,915,335	-	-	1,915,335	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	390,519	-	-	390,519	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	12,872	-	-	12,872	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	110,681	-	-	110,681	-	-	-	-	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	687,585	-	-	687,585	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	170,496	-	-	170,496	-	-	-	-	-	-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 4,172,132	$ -	$ -	$ 4,172,132	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense												
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ 951,702	-	-	-	141,164	-	112,584	190,987	38,088	66,453
581 LOAD DISPATCHING	LB581	P362	147,043	-	-	-	147,043	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	886,395	-	-	-	886,395	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	2,177,118	-	-	-	-	-	552,863	982,441	231,117	410,697
584 UNDERGROUND LINE EXPENSES	LB584	P367	377,223	-	-	-	-	-	133,353	198,867	18,064	26,939
585 STREET LIGHTING EXPENSE	LB585	P373	-	-	-	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	3,140,532	-	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012		-	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	1,500,244	-	-	-	187,083	-	287,206	469,992	80,133	136,928
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 9,180,257	$ -	$ -	$ -	$ 1,361,685	$ -	$ 1,086,006	$ 1,842,286	$ 367,402	$ 641,017

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-	-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	11,354	6,329	4,046	367,356	13,341	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P373	-	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	3,140,532	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	98,167	54,719	34,986	35,680	115,350	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 109,521	$ 61,048	$ 39,032	$ 3,543,567	$ 128,691	$ -	$ -	$ -

Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)												
Distribution Maintenance Labor Expense												
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	374,744	-	-	-	374,744	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	1,642,806	-	-	-	-	-	417,178	741,328	174,396	309,903
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	619,769	-	-	-	-	-	219,096	326,734	29,679	44,260
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	72,618	-	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	5,976	-	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 2,715,913	$ -	$ -	$ -	$ 374,744	$ -	$ 636,275	$ 1,068,063	$ 204,075	$ 354,163
Total Distribution Operation and Maintenance Labor Expenses		PDIST	$ 11,896,170	-	-	-	1,736,429	-	1,722,281	2,910,349	571,478	995,179
Transmission and Distribution Labor Expenses			$ 16,068,302	-	-	4,172,132	1,736,429	-	1,722,281	2,910,349	571,478	995,179
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 49,525,423	$ 18,103,460	$ 15,353,661	$ 4,172,132	$ 1,736,429	$ -	$ 1,722,281	$ 2,910,349	$ 571,478	$ 995,179
Customer Accounts Expense												
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 1,093,166	-	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	370,757	-	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	3,518,496	-	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 4,982,419	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense												
907 SUPERVISION	LB907	F026	$ 145,428	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	617,471	-	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	322,553	-	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 1,085,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		$ 55,593,293	18,103,460	15,353,661	4,172,132	1,736,429	-	1,722,281	2,910,349	571,478	995,179

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	46,627	25,991	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	5,976	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 46,627	$ 25,991	$ -	$ -	$ 5,976	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	156,149	87,039	39,032	3,543,567	134,667	-	-	-
Transmission and Distribution Labor Expenses			156,149	87,039	39,032	3,543,567	134,667	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 156,149	$ 87,039	$ 39,032	$ 3,543,567	$ 134,667	$ -	$ -	$ -
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	1,093,166	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	370,757	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	3,518,496	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ 4,982,419	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	145,428	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	617,471	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	322,553	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,085,452	$ -
Sub-Total Labor Exp	LBSUB7		156,149	87,039	39,032	3,543,567	134,667	4,982,419	1,085,452	-

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Description	Name	Functional Vector	Total System	Production Demand LOLP	Production Energy Energy	Transmission Demand Demand	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Labor Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$ 20,000,454	6,512,969	5,523,691	1,500,982	624,704	-	619,614	1,047,038	205,597	358,029
921 OFFICE SUPPLIES AND EXPENSES	LB920	LBSUB7	-	-	-	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(2,892,849)	(942,030)	(798,942)	(217,101)	(90,357)	-	(89,621)	(151,443)	(29,737)	(51,785)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES	LB925	LBSUB7	-	-	-	-	-	-	-	-	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	165,400	53,861	45,680	12,413	5,166	-	5,124	8,659	1,700	2,961
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB932	PGP	502,249	306,591	-	47,089	18,527	-	28,442	46,543	7,936	13,560
Total Administrative and General Expense	LBAG		$ 17,775,254	$ 5,931,392	$ 4,770,429	$ 1,343,383	$ 558,040	$ -	$ 563,560	$ 950,797	$ 185,495	$ 322,765
Total Operation and Maintenance Expenses	TLB		$ 73,368,547	$ 24,034,852	$ 20,124,090	$ 5,515,515	$ 2,294,469	$ -	$ 2,285,841	$ 3,861,146	$ 756,973	$ 1,317,944
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 73,368,547	$ 24,034,852	$ 20,124,090	$ 5,515,515	$ 2,294,469	$ -	$ 2,285,841	$ 3,861,146	$ 756,973	$ 1,317,944

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	56,177	31,313	14,042	1,274,847	48,448	1,792,494	390,506	-
921 OFFICE SUPPLIES AND EXPENSES	LB920	LBSUB7	-	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(8,125)	(4,529)	(2,031)	(184,393)	(7,008)	(259,265)	(56,483)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES	LB925	LBSUB7	-	-	-	-	-	-	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	465	259	116	10,543	401	14,824	3,229	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB932	PGP	9,721	5,419	3,465	3,533	11,423	-	-	-
Total Administrative and General Expense	LBAG		$ 58,237	$ 32,462	$ 15,592	$ 1,104,530	$ 53,265	$ 1,548,053	$ 337,253	$ -
Total Operation and Maintenance Expenses	TLB		$ 214,386	$ 119,501	$ 54,624	$ 4,648,098	$ 187,932	$ 6,530,471	$ 1,422,705	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 214,386	$ 119,501	$ 54,624	$ 4,648,098	$ 187,932	$ 6,530,471	$ 1,422,705	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
				LOLP	Energy	Demand	General	Specific	Demand	Customer	Demand	Customer
Other Expenses												
Depreciation Expenses												
Steam Production	DEPRTP	PPRTL	$ 179,722,988	179,722,988	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	5,725,980	5,725,980	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	12,399,786	12,399,786	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	12,287,717	-	-	12,287,717	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	42,603,324	-	-	-	5,312,707	-	8,155,954	13,346,638	2,275,586	3,888,419
General & Common Plant	DEPRDP6	PGP	24,383,040	14,884,317	-	2,286,078	899,429	-	1,380,784	2,259,555	385,251	658,300
Intangible Plant	DEPRDP7	PINT		-	-	-	-	-	-	-	-	-
Total Depreciation Expense	TDEPR		$ 277,122,836	212,733,072	-	14,573,795	6,212,136	-	9,536,738	15,606,193	2,660,837	4,546,719
Regulatory Credits												
Production	RCTNP	F017	$ -	-	-	-	-	-	-	-	-	-
Transmission	RCTNT	PTRAN	-	-	-	-	-	-	-	-	-	-
Distribution	RDTND	PDIST	-	-	-	-	-	-	-	-	-	-
Common	RCTNC	PGP	-	-	-	-	-	-	-	-	-	-
Total Regulatory Credits	TRCTN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accretion Expense												
Production	ACRTNP	F017	$ -	-	-	-	-	-	-	-	-	-
Transmission	ACRTNT	PTRAN	-	-	-	-	-	-	-	-	-	-
Distribution	ACRTND	PDIST	-	-	-	-	-	-	-	-	-	-
Common	ACRTNC	PGP	-	-	-	-	-	-	-	-	-	-
Total Accretion Expense	TACRTN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes & Other	PTAX	TUP	$ 42,336,722	25,721,711	-	4,076,189	1,563,612	-	2,400,424	3,928,124	669,740	1,144,422
Amortization of Investment Tax Credit	OTAX	TUP	$ (916,996)	(557,122)	-	(88,289)	(33,867)	-	(51,992)	(85,082)	(14,506)	(24,788)
Gain on Disposition of Allowances	OT	TUP	$ -	-	-	-	-	-	-	-	-	-
Interest	INTLTD	TUP	$ 75,433,705	45,829,811	-	7,262,774	2,785,976	-	4,276,970	6,998,958	1,193,314	2,039,081
Other Deductions	DEDUCT	TUP	$ -	-	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 393,976,267	$ 283,727,472	$ -	$ 25,824,469	$ 10,527,856	$ -	$ 16,162,141	$ 26,448,193	$ 4,509,385	$ 7,705,435
Total Cost of Service (O&M + Other Expenses)			$ 1,037,412,928	$ 395,685,570	$ 397,495,519	$ 60,290,462	$ 18,602,235	$ -	$ 29,362,316	$ 48,540,917	$ 8,678,514	$ 14,929,226

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	2,787,721	1,553,897	993,517	1,013,216	3,275,670	-	-	-
General & Common Plant	DEPRDP6	PGP	471,955	263,071	168,200	171,535	554,563	-	-	-
Intangible Plant	DEPRDP7	PINT	-	-	-	-	-	-	-	-
Total Depreciation Expense	TDEPR		3,259,675	1,816,969	1,161,717	1,184,751	3,830,233	-	-	-
Regulatory Credits										
Production	RCTNP	F017	-	-	-	-	-	-	-	-
Transmission	RCTNT	PTRAN	-	-	-	-	-	-	-	-
Distribution	RDTND	PDIST	-	-	-	-	-	-	-	-
Common	RCTNC	PGP	-	-	-	-	-	-	-	-
Total Regulatory Credits	TRCTN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accretion Expense										
Production	ACRTNP	F017	-	-	-	-	-	-	-	-
Transmission	ACRTNT	PTRAN	-	-	-	-	-	-	-	-
Distribution	ACRTND	PDIST	-	-	-	-	-	-	-	-
Common	ACRTNC	PGP	-	-	-	-	-	-	-	-
Total Accretion Expense	TACRTN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes & Other	PTAX	TUP	820,470	457,336	292,408	298,205	964,081	-	-	-
Amortization of Investment Tax Credit	OTAX	TUP	(17,771)	(9,906)	(6,333)	(6,459)	(20,882)	-	-	-
Gain on Disposition of Allowances	OT	TUP	-	-	-	-	-	-	-	-
Interest	INTLTD	TUP	1,461,877	814,862	520,999	531,329	1,717,757	-	-	-
Other Deductions	DEDUCT	TUP	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 5,524,250	$ 3,079,261	$ 1,968,790	$ 2,007,826	$ 6,491,189	$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 6,641,280	$ 3,701,902	$ 2,301,703	$ 15,926,141	$ 8,165,124	$ 22,203,328	$ 4,888,693	$ -

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				Production Demand	Production Energy	Transmission Demand	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
Description	**Name**	**Functional Vector**	**Total System**	**LOLP**	**Energy**	**Demand**	**General**	**Specific**	**Demand**	**Customer**	**Demand**	**Customer**
External Functional Vectors												
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.253943	0.451257	0.106157	0.188643
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.253943	0.451257	0.106157	0.188643
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.353513	0.527187	0.047887	0.071413
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		12,601,985	11,007,917	1,594,068	-	-	-	-	-	-	-
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		7,744,702	30,396	7,714,306	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		262,377	262,377	-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		158,283	86,045	72,238	-	-	-	-	-	-	-
Distribution Operation Labor	F023		8,228,555	-	-	-	1,220,520.97	-	973,421.84	1,651,299.68	329,314.48	574,563.39
Distribution Maintenance Labor	F024		2,715,913	-	-	-	374,744.00	-	636,274.68	1,068,062.67	204,075.04	354,162.61
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		1,160,271,505	-	-	-	-	-	342,041,384	559,726,383	95,432,668	163,071,070
Purchase Power Demand		F017	27,272,357	27,272,357	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	22,555,449	-	22,555,449	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP		49,827,806	27,272,357	22,555,449	-	-	-	-	-	-	-
Intallations on Customer Premises - Plant in Service	F013		1.00000	-	-	-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors												
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.610437	-	0.093757	0.036887	-	0.056629	0.092669	0.015800	0.026998
Total Distribution Plant		PDIST	1.000000	-	-	-	0.124702	-	0.191439	0.313277	0.053413	0.091270
Total Transmission Plant		PTRAN	1.000000	-	-	1.000000	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.147080	0.629675	0.057428	0.013454	-	0.021994	0.036811	0.006947	0.012036
Total Plant in Service		TPIS	1.000000	0.610168	-	0.093710	0.036927	-	0.056689	0.092768	0.015817	0.027027
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.327591	0.274288	0.075175	0.031273	-	0.031156	0.052627	0.010317	0.017963
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.144948	0.676053	0.049836	0.009548	-	0.018387	0.030749	0.005782	0.010014
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.873507	0.126493	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.003925	0.996075	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	1.000000	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.543615	0.456385	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	1.000000	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	1.0000000	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	0.148327	-	0.118298	0.200679	0.040021	0.069826
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	0.137981	-	0.234277	0.393261	0.075140	0.130403
Sub-Total Labor Exp		LBSUB7	1.000000	0.325641	0.276178	0.075047	0.031234	-	0.030980	0.052351	0.010280	0.017901
Total General Plant		PGP	1.000000	0.610437	-	0.093757	0.036887	-	0.056629	0.092669	0.015800	0.026998
Total Production Plant		PPRTL	1.000000	1.000000	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	1.000000	0.610437	-	0.093757	0.036887	-	0.056629	0.092669	0.015800	0.026998

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
External Functional Vectors										
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.642093	0.357907	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-	-
Distribution Operation Labor	F023		98,167.48	54,719.33	34,985.95	3,176,211.63	115,350.25	-	-	-
Distribution Maintenance Labor	F024		46,627.48	25,990.52	-	-	5,976.00	-	-	-
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP		-	-	-	-	-	-	-	-
Intallations on Customer Premises - Plant in Service	F013		-	-	-	-	-	1.00000	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors										
Total Prod, Trans, and Dist Plant		PT&D	0.019356	0.010789	0.006898	0.007035	0.022744	-	-	-
Total Distribution Plant		PDIST	0.065434	0.036474	0.023320	0.023783	0.076888	-	-	-
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.001861	0.001037	0.000555	0.023191	0.002789	0.036996	0.008146	-
Total Plant in Service		TPIS	0.019376	0.010801	0.006906	0.007043	0.022768	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.002922	0.001629	0.000745	0.063353	0.002561	0.089009	0.019391	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.001241	0.000692	0.000366	0.016248	0.002225	0.027768	0.006142	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.011930	0.006650	0.004252	0.385999	0.014018	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	0.017168	0.009570	-	-	0.002200	-	-	-
Sub-Total Labor Exp		LBSUB7	0.002809	0.001566	0.000702	0.063741	0.002422	0.089623	0.019525	-
Total General Plant		PGP	0.019356	0.010789	0.006898	0.007035	0.022744	-	-	-
Total Production Plant		PPRTL	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.019356	0.010789	0.006898	0.007035	0.022744	-	-	-

Exhibit WSS-31

Electric Cost of Service Study
Class Allocation
(Kentucky Utilities)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Plant in Service											
Power Production Plant											
Production Demand - LOLP	TPIS	PLPPDB	GPLOLPDA	$ 6,073,014,123	$ 2,490,784,384	$ 670,878,802	$ 43,048,460	$ 625,621,337	$ 27,180,233	$ 601,676,613	$ 1,101,435,630
Production Energy	TPIS	PLPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 6,073,014,123	$ 2,490,784,384	$ 670,878,802	$ 43,048,460	$ 625,621,337	$ 27,180,233	$ 601,676,613	$ 1,101,435,630
Transmission Plant											
Transmission Demand	TPIS	PLTRB	NCPT	$ 1,314,530,303	$ 581,215,750	$ 149,186,114	$ 15,268,347	$ 133,087,047	$ 5,718,859	$ 117,737,434	$ 191,751,289
Distribution Poles											
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TPIS	PLDSG	NCPP	$ 354,760,183	$ 171,330,235	$ 43,976,943	$ 4,500,789	$ 39,231,275	$ 1,685,800	$ 34,706,531	$ 56,524,266
Distribution Primary & Secondary Lines											
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	282,159,692	$ 136,268,073	$ 34,977,208	$ 3,579,718	$ 31,202,725	$ 1,340,807	$ 27,603,955	$ 44,956,763
Primary Customer	TPIS	PLDPLC	PCust08	548,452,178	$ 440,598,864	$ 82,429,964	$ 422,398	$ 4,425,216	$ 203,229	$ 762,109	$ 255,033
Secondary Demand	TPIS	PLDSLD	SICD	127,023,977	$ 105,210,533	$ 19,625,864	$ 1,422,586	$ -	$ -	$ -	$ -
Secondary Customer	TPIS	PLDSLC	PCust07	256,429,859	$ 208,143,126	$ 38,940,705	$ 199,545	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		PLDLT		$ 1,214,065,706	$ 890,220,596	$ 175,973,741	$ 5,624,246	$ 35,627,941	$ 1,544,036	$ 28,366,064	$ 45,211,795
Distribution Line Transformers											
Demand	TPIS	PLDLTD	SICDT	$ 185,167,208	$ 126,572,323	$ 23,610,670	$ 1,711,426	$ 17,444,145	$ -	$ 14,887,651	$ -
Customer	TPIS	PLDLTC	PCust09	153,841,916	$ 123,692,201	$ 23,141,103	$ 118,583	$ 1,242,320	$ -	$ 213,952	$ -
Total Line Transformers		PLDLTT		$ 339,009,124	$ 250,264,524	$ 46,751,773	$ 1,830,008	$ 18,686,465	$ -	$ 15,101,603	$ -
Distribution Services											
Customer	TPIS	PLDSC	C02	$ 129,708,296	$ 102,581,566	$ 23,061,068	$ 208,650	$ 2,996,910	$ -	$ 857,403	$ -
Distribution Meters											
Customer	TPIS	PLDMC	MGPA	$ 77,142,557	$ 46,508,310	$ 18,767,490	$ 383,084	$ 5,867,892	$ 1,147,531	$ 1,049,543	$ 2,032,818
Distribution Street & Customer Lighting											
Customer	TPIS	PLDSCL	PCust04	$ 148,542,746	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TPIS	PLCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	TPIS	PLCSI	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	TPIS	PLSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 9,650,773,038	$ 4,532,905,364	$ 1,128,595,931	$ 70,863,586	$ 861,118,868	$ 37,276,458	$ 799,495,189	$ 1,396,955,797

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Plant in Service												
Power Production Plant												
Production Demand - LOLP	TPIS	PLPPDB	GPLOLPDA	$ 358,533,878	$ 148,468,386	$ 967,726	$ 35,209	$ 575,745	$ 74,108	$ 5,011	$ 3,325,058	$ 403,543
Production Energy	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 358,533,878	$ 148,468,386	$ 967,726	$ 35,209	$ 575,745	$ 74,108	$ 5,011	$ 3,325,058	$ 403,543
Transmission Plant												
Transmission Demand	TPIS	PLTRB	NCPT	$ 66,495,202	$ 44,556,885	$ 8,974,247	$ 326,511	$ 87,970	$ 123,876	$ 773	$ -	$ -
Distribution Poles												
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TPIS	PLDSG	NCPP	$ -	$ -	$ 2,645,420	$ 96,249	$ 25,932	$ 36,516	$ 228	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ -	$ -	$ 2,104,044	$ 76,552	$ 20,625	$ 29,043	$ 181	$ -	$ -
Primary Customer	TPIS	PLDPLC	PCust08	$ -	$ -	$ 19,182,023	$ 11,955	$ 147,441	$ 3,985	$ 9,962	$ -	$ -
Secondary Demand	TPIS	PLDSLD	SICD	$ -	$ -	$ 731,162	$ 26,602	$ 7,167	$ -	$ 63	$ -	$ -
Secondary Customer	TPIS	PLDSLC	PCust07	$ -	$ -	$ 9,061,771	$ 5,647	$ 69,652	$ -	$ 9,412	$ -	$ -
Total Distribution Primary & Secondary Lines		PLDLT		$ -	$ -	$ 31,079,000	$ 120,756	$ 244,885	$ 33,028	$ 19,619	$ -	$ -
Distribution Line Transformers												
Demand	TPIS	PLDLTD	SICDT	$ -	$ -	$ 879,616	$ 32,003	$ 8,622	$ 20,677	$ 76	$ -	$ -
Customer	TPIS	PLDLTC	PCust09	$ -	$ -	$ 5,385,095	$ 3,356	$ 41,392	$ 1,119	$ 2,797	$ -	$ -
Total Line Transformers		PLDLTT		$ -	$ -	$ 6,264,710	$ 35,359	$ 50,014	$ 21,795	$ 2,873	$ -	$ -
Distribution Services												
Customer	TPIS	PLDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 2,699	$ -	$ -	$ -
Distribution Meters												
Customer	TPIS	PLDMC	MGPA	$ 1,007,857	$ 62,215	$ -	$ 11,355	$ 139,943	$ 5,286	$ 159,234	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TPIS	PLDSCL	PCust04	$ -	$ -	$ 148,542,746	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TPIS	PLCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TPIS	PLCSI	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TPIS	PLSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 426,036,937	$ 193,087,486	$ 198,473,848	$ 625,438	$ 1,124,489	$ 297,309	$ 187,737	$ 3,325,058	$ 403,543

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Net Utility Plant											
Power Production Plant											
Production Demand - LOLP	NTPLANT	UPPPDB	NPLOLPDA	$ 3,680,027,941	$ 1,508,811,050	$ 406,389,793	$ 26,076,923	$ 378,974,749	$ 16,464,627	$ 364,470,055	$ 667,202,773
Production Energy	NTPLANT	UPPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 3,680,027,941	$ 1,508,811,050	$ 406,389,793	$ 26,076,923	$ 378,974,749	$ 16,464,627	$ 364,470,055	$ 667,202,773
Transmission Plant											
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 1,036,890,044	$ 458,457,917	$ 117,676,706	$ 12,043,539	$ 104,977,903	$ 4,510,986	$ 92,870,261	$ 151,251,745
Distribution Poles											
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	NTPLANT	UPDSG	NCPP	$ 246,738,027	$ 119,161,299	$ 30,586,251	$ 3,130,328	$ 27,285,608	$ 1,172,485	$ 24,138,619	$ 39,312,996
Distribution Primary & Secondary Lines											
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	196,243,910	$ 94,775,335	$ 24,326,877	$ 2,489,717	$ 21,701,699	$ 932,540	$ 19,198,731	$ 31,267,722
Primary Customer	NTPLANT	UPDPLC	PCust08	381,452,075	$ 306,439,390	$ 57,330,579	$ 293,780	$ 3,077,766	$ 141,347	$ 530,052	$ 177,377
Secondary Demand	NTPLANT	UPDSLD	SICD	88,346,006	$ 73,174,614	$ 13,649,917	$ 989,418	$ -	$ -	$ -	$ -
Secondary Customer	NTPLANT	UPDSLC	PCust07	178,348,644	$ 144,764,905	$ 27,083,515	$ 138,785	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		UPDLT		$ 844,390,636	$ 619,154,244	$ 122,390,887	$ 3,911,700	$ 24,779,466	$ 1,073,887	$ 19,728,783	$ 31,445,099
Distribution Line Transformers											
Demand	NTPLANT	UPDLTD	SICDT	$ 128,785,004	$ 88,031,878	$ 16,421,375	$ 1,190,308	$ 12,132,517	$ -	$ 10,354,458	$ -
Customer	NTPLANT	UPDLTC	PCust09	106,998,058	$ 86,028,734	$ 16,094,788	$ 82,475	$ 864,042	$ -	$ 148,805	$ -
Total Line Transformers		UPDLTT		$ 235,783,062	$ 174,060,612	$ 32,516,164	$ 1,272,783	$ 12,996,559	$ -	$ 10,503,263	$ -
Distribution Services											
Customer	NTPLANT	UPDSC	C02	$ 90,212,968	$ 71,346,150	$ 16,039,124	$ 145,118	$ 2,084,370	$ -	$ 596,329	$ -
Distribution Meters											
Customer	NTPLANT	UPDMC	MNPA	$ 53,653,152	$ 32,341,236	$ 13,050,653	$ 266,391	$ 4,080,451	$ 797,977	$ 729,838	$ 1,413,594
Distribution Street & Customer Lighting											
Customer	NTPLANT	UPDSCL	PCust04	$ 103,312,451	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	NTPLANT	UPCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	NTPLANT	UPCSI	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	NTPLANT	UPSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 6,291,008,281	$ 2,983,332,508	$ 738,649,578	$ 46,846,782	$ 555,179,106	$ 24,019,962	$ 513,037,149	$ 890,626,207

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Net Utility Plant												
Power Production Plant												
Production Demand - LOLP	NTPLANT	UPPPDB	NPLOLPDA	$ 217,184,547	$ 89,935,822	$ 586,207	$ 21,328	$ 348,762	$ 44,892	$ 3,036	$ 3,141,953	$ 371,427
Production Energy	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 217,184,547	$ 89,935,822	$ 586,207	$ 21,328	$ 348,762	$ 44,892	$ 3,036	$ 3,141,953	$ 371,427
Transmission Plant												
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 52,450,835	$ 35,146,083	$ 7,078,808	$ 257,549	$ 69,390	$ 97,712	$ 610	$ -	$ -
Distribution Poles												
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	NTPLANT	UPDSG	NCPP	$ -	$ -	$ 1,839,907	$ 66,941	$ 18,036	$ 25,397	$ 158	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ -	$ -	$ 1,463,376	$ 53,242	$ 14,345	$ 20,200	$ 126	$ -	$ -
Primary Customer	NTPLANT	UPDPLC	PCust08	$ -	$ -	$ 13,341,222	$ 8,315	$ 102,546	$ 2,772	$ 6,929	$ -	$ -
Secondary Demand	NTPLANT	UPDSLD	SICD	$ -	$ -	$ 508,528	$ 18,502	$ 4,985	$ -	$ 44	$ -	$ -
Secondary Customer	NTPLANT	UPDSLC	PCust07	$ -	$ -	$ 6,302,521	$ 3,928	$ 48,444	$ -	$ 6,546	$ -	$ -
Total Distribution Primary & Secondary Lines		UPDLT		$ -	$ -	$ 21,615,647	$ 83,986	$ 170,319	$ 22,971	$ 13,645	$ -	$ -
Distribution Line Transformers												
Demand	NTPLANT	UPDLTD	SICDT	$ -	$ -	$ 611,778	$ 22,258	$ 5,997	$ 14,381	$ 53	$ -	$ -
Customer	NTPLANT	UPDLTC	PCust09	$ -	$ -	$ 3,745,369	$ 2,334	$ 28,788	$ 778	$ 1,945	$ -	$ -
Total Line Transformers		UPDLTT		$ -	$ -	$ 4,357,147	$ 24,593	$ 34,785	$ 15,159	$ 1,998	$ -	$ -
Distribution Services												
Customer	NTPLANT	UPDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 1,878	$ -	$ -	$ -
Distribution Meters												
Customer	NTPLANT	UPDMC	MNPA	$ 700,850	$ 43,263	$ -	$ 7,896	$ 97,314	$ 3,676	$ 120,013	$ -	$ -
Distribution Street & Customer Lighting												
Customer	NTPLANT	UPDSCL	PCust04	$ -	$ -	$ 103,312,451	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	NTPLANT	UPCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	NTPLANT	UPCSI	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	NTPLANT	UPSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 270,336,232	$ 125,125,168	$ 138,790,167	$ 462,294	$ 738,606	$ 211,684	$ 139,460	$ 3,141,953	$ 371,427

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Net Cost Rate Base											
Power Production Plant											
Production Demand - LOLP	RB	RBPPDB	RBLOLPDA	$ 2,975,438,420	$ 1,219,918,258	$ 328,578,140	$ 21,083,962	$ 306,412,268	$ 13,312,137	$ 294,684,795	$ 539,453,131
Production Energy	RB	RBPPEB	E01	79,624,711	$ 27,493,896	$ 7,762,757	$ 594,640	$ 7,860,100	$ 355,222	$ 8,253,333	$ 17,832,601
Total Power Production Plant		RBPPT		$ 3,055,063,131	$ 1,247,412,154	$ 336,340,897	$ 21,678,601	$ 314,272,367	$ 13,667,359	$ 302,938,128	$ 557,285,732
Transmission Plant											
Transmission Demand	RB	RBTRB	NCPT	$ 853,028,865	$ 377,164,232	$ 96,810,291	$ 9,907,981	$ 86,363,237	$ 3,711,099	$ 76,402,521	$ 124,431,809
Distribution Poles											
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	RB	RBDSG	NCPP	$ 200,340,313	$ 96,753,679	$ 24,834,677	$ 2,541,687	$ 22,154,702	$ 952,006	$ 19,599,486	$ 31,920,406
Distribution Primary & Secondary Lines											
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	159,803,702	$ 77,176,659	$ 19,809,659	$ 2,027,406	$ 17,671,947	$ 759,378	$ 15,633,750	$ 25,461,670
Primary Customer	RB	RBDPLC	PCust08	310,404,048	$ 249,362,982	$ 46,652,371	$ 239,062	$ 2,504,512	$ 115,020	$ 431,326	$ 144,339
Secondary Demand	RB	RBDSLD	SICD	71,898,861	$ 59,551,887	$ 11,108,747	$ 805,221	$ -	$ -	$ -	$ -
Secondary Customer	RB	RBDSLC	PCust07	145,014,673	$ 117,707,850	$ 22,021,513	$ 112,845	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		RBDLT		$ 687,121,284	$ 503,799,379	$ 99,592,291	$ 3,184,533	$ 20,176,458	$ 874,398	$ 16,065,076	$ 25,606,010
Distribution Line Transformers											
Demand	RB	RBDLTD	SICDT	$ 104,229,018	$ 71,246,464	$ 13,290,242	$ 963,347	$ 9,819,158	$ -	$ 8,380,130	$ -
Customer	RB	RBDLTC	PCust09	86,596,282	$ 69,625,269	$ 13,025,926	$ 66,749	$ 699,291	$ -	$ 120,432	$ -
Total Line Transformers		RBDLTT		$ 190,825,300	$ 140,871,733	$ 26,316,168	$ 1,030,096	$ 10,518,449	$ -	$ 8,500,561	$ -
Distribution Services											
Customer	RB	RBDSC	C02	$ 73,005,398	$ 57,737,309	$ 12,979,759	$ 117,437	$ 1,686,789	$ -	$ 482,583	$ -
Distribution Meters											
Customer	RB	RBDMC	MRBA	$ 45,031,431	$ 27,151,049	$ 10,956,258	$ 223,640	$ 3,425,612	$ 669,916	$ 612,712	$ 1,186,737
Distribution Street & Customer Lighting											
Customer	RB	RBDSCL	PCust04	$ 83,606,234	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	RB	RBCAE	PCust05	$ 8,704,114	$ 5,654,852	$ 2,115,886	$ 54,213	$ 283,976	$ 13,042	$ 244,532	$ 81,830
Customer Service & Info.											
Customer	RB	RBCSI	PCust05	$ 1,105,953	$ 718,511	$ 268,847	$ 6,888	$ 36,082	$ 1,657	$ 31,070	$ 10,397
Sales Expense											
Customer	RB	RBSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 5,197,832,023	$ 2,457,262,896	$ 610,215,074	$ 38,745,077	$ 458,917,674	$ 19,889,476	$ 424,876,670	$ 740,522,922

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Net Cost Rate Base												
Power Production Plant												
Production Demand - LOLP	RB	RBPPDB	RBLOLPDA	$ 175,600,115	$ 72,715,766	$ 473,966	$ 17,244	$ 281,984	$ 36,296	$ 2,454	$ 2,576,969	$ 290,934
Production Energy	RB	RBPPEB	E01	$ 6,206,391	$ 2,677,141	$ 555,781	$ 20,221	$ 11,068	$ 1,510	$ 51	$ -	$ -
Total Power Production Plant		RBPPT		$ 181,806,506	$ 75,392,907	$ 1,029,746	$ 37,465	$ 293,052	$ 37,806	$ 2,505	$ 2,576,969	$ 290,934
Transmission Plant												
Transmission Demand	RB	RBTRB	NCPT	$ 43,150,262	$ 28,913,985	$ 5,823,595	$ 211,880	$ 57,086	$ 80,386	$ 502	$ -	$ -
Distribution Poles												
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	RB	RBDSG	NCPP	$ -	$ -	$ 1,493,923	$ 54,354	$ 14,644	$ 20,621	$ 129	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ -	$ -	$ 1,191,644	$ 43,356	$ 11,681	$ 16,449	$ 103	$ -	$ -
Primary Customer	RB	RBDPLC	PCust08	$ -	$ -	$ 10,856,329	$ 6,766	$ 83,446	$ 2,255	$ 5,638	$ -	$ -
Secondary Demand	RB	RBDSLD	SICD	$ -	$ -	$ 413,856	$ 15,057	$ 4,057	$ -	$ 36	$ -	$ -
Secondary Customer	RB	RBDSLC	PCust07	$ -	$ -	$ 5,124,558	$ 3,194	$ 39,389	$ -	$ 5,323	$ -	$ -
Total Distribution Primary & Secondary Lines		RBDLT		$ -	$ -	$ 17,586,389	$ 68,373	$ 138,573	$ 18,704	$ 11,099	$ -	$ -
Distribution Line Transformers												
Demand	RB	RBDLTD	SICDT	$ -	$ -	$ 495,128	$ 18,014	$ 4,853	$ 11,639	$ 43	$ -	$ -
Customer	RB	RBDLTC	PCust09	$ -	$ -	$ 3,031,223	$ 1,889	$ 23,299	$ 630	$ 1,574	$ -	$ -
Total Line Transformers		RBDLTT		$ -	$ -	$ 3,526,351	$ 19,903	$ 28,153	$ 12,268	$ 1,617	$ -	$ -
Distribution Services												
Customer	RB	RBDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 1,519	$ -	$ -	$ -
Distribution Meters												
Customer	RB	RBDMC	MRBA	$ 588,376	$ 36,320	$ -	$ 6,629	$ 81,697	$ 3,086	$ 89,399	$ -	$ -
Distribution Street & Customer Lighting												
Customer	RB	RBDSCL	PCust04	$ -	$ -	$ 83,606,234	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	RB	RBCAE	PCust05	$ 6,393	$ 639	$ 246,194	$ 153	$ 1,892	$ 256	$ 256	$ -	$ -
Customer Service & Info.												
Customer	RB	RBCSI	PCust05	$ 812	$ 81	$ 31,282	$ 19	$ 240	$ 32	$ 32	$ -	$ -
Sales Expense												
Customer	RB	RBSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 225,552,349	$ 104,343,933	$ 113,343,713	$ 398,777	$ 615,338	$ 174,679	$ 105,539	$ 2,576,969	$ 290,934

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Operation and Maintenance Expenses											
Power Production Plant											
Production Demand - LOLP	TOM	OMPPDB	POMLOLPDA	133,195,931	54,624,948	14,712,923	944,088	13,720,390	596,085	13,195,262	24,155,388
Production Energy	TOM	OMPPEB	E01	555,456,787	191,795,621	54,152,488	4,148,168	54,831,541	2,478,006	57,574,714	124,399,061
Total Power Production Plant		OMPPT		688,652,718	246,420,569	68,865,411	5,092,256	68,551,931	3,074,090	70,769,976	148,554,449
Transmission Plant											
Transmission Demand	TOM	OMTRB	NCPT	57,756,584	25,536,905	6,554,798	670,846	5,847,452	251,270	5,173,036	8,424,986
Distribution Poles											
Specific	TOM	OMDPS	NCPP	-	-	-	-	-	-	-	-
Distribution Substation											
General	TOM	OMDSG	NCPP	9,282,793	4,483,094	1,150,718	117,769	1,026,541	44,111	908,145	1,479,036
Distribution Primary & Secondary Lines											
Primary Specific	TOM	OMDPLS	NCPP	-	-	-	-	-	-	-	-
Primary Demand	TOM	OMDPLD	NCPP	12,963,444	6,260,651	1,606,980	164,465	1,433,567	61,602	1,268,226	2,065,477
Primary Customer	TOM	OMDPLC	Cust08	23,791,490	19,112,052	3,576,807	18,320	191,880	8,814	33,096	11,061
Secondary Demand	TOM	OMDSLD	SICD	5,561,431	4,606,384	859,270	62,284	-	-	-	-
Secondary Customer	TOM	OMDSLC	Cust07	10,375,667	8,341,894	1,561,180	7,996	83,750	-	14,446	-
Total Distribution Primary & Secondary Lines		OMDLT		52,692,031	38,320,981	7,604,237	253,065	1,709,197	70,416	1,315,768	2,076,538
Distribution Line Transformers											
Demand	TOM	OMDLTD	SICDT	2,648,296	1,810,261	337,684	24,477	249,489	-	212,926	-
Customer	TOM	OMDLTC	Cust09	2,200,276	1,768,991	331,066	1,696	17,760	-	3,063	-
Total Line Transformers		OMDLTT		4,848,571	3,579,252	668,750	26,173	267,250	-	215,989	-
Distribution Services											
Customer	TOM	OMDSC	C02	1,814,383	1,434,929	322,582	2,919	41,921	-	11,994	-
Distribution Meters											
Customer	TOM	OMDMC	MOMA	11,537,188	6,970,017	2,812,610	57,411	879,398	171,976	157,291	304,650
Distribution Street & Customer Lighting											
Customer	TOM	OMDSCL	C04	2,077,842	-	-	-	-	-	-	-
Customer Accounts Expense											
Customer	TOM	OMCAE	C05	56,459,203	36,676,717	13,728,044	351,559	1,841,124	84,573	1,587,819	530,655
Customer Service & Info.											
Customer	TOM	OMCSI	C10	7,173,760	5,742,083	1,074,627	5,504	57,649	2,648	9,944	3,323
Sales Expense											
Customer	TOM	OMSEC	C06	-	-	-	-	-	-	-	-
Total		OMT		892,295,073	369,164,547	102,781,777	6,577,503	80,222,463	3,699,084	80,149,961	161,373,638

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Operation and Maintenance Expenses												
Power Production Plant												
Production Demand - LOLP	TOM	OMPPDB	POMLOLPDA	$ 7,862,942	$ 3,256,034	$ 21,223	$ 772	$ 12,627	$ 1,625	$ 110	$ 91,514	$ -
Production Energy	TOM	OMPPEB	E01	$ 43,295,379	$ 18,675,564	$ 3,877,090	$ 141,060	$ 77,209	$ 10,533	$ 353	$ -	$ -
Total Power Production Plant		OMPPT		$ 51,158,321	$ 21,931,598	$ 3,898,313	$ 141,833	$ 89,835	$ 12,158	$ 463	$ 91,514	$ -
Transmission Plant												
Transmission Demand	TOM	OMTRB	NCPT	$ 2,921,603	$ 1,957,698	$ 394,302	$ 14,346	$ 3,865	$ 5,443	$ 34	$ -	$ -
Distribution Poles												
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TOM	OMDSG	NCPP	$ -	$ -	$ 69,221	$ 2,518	$ 679	$ 955	$ 6	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ -	$ -	$ 96,667	$ 3,517	$ 948	$ 1,334	$ 8	$ -	$ -
Primary Customer	TOM	OMDPLC	Cust08	$ -	$ -	$ 831,941	$ 518	$ 6,395	$ 173	$ 432	$ -	$ -
Secondary Demand	TOM	OMDSLD	SICD	$ -	$ -	$ 32,012	$ 1,165	$ 314	$ -	$ 3	$ -	$ -
Secondary Customer	TOM	OMDSLC	Cust07	$ -	$ -	$ 363,120	$ 226	$ 2,791	$ 75	$ 189	$ -	$ -
Total Distribution Primary & Secondary Lines		OMDLT		$ -	$ -	$ 1,323,741	$ 5,427	$ 10,447	$ 1,583	$ 632	$ -	$ -
Distribution Line Transformers												
Demand	TOM	OMDLTD	SICDT	$ -	$ -	$ 12,580	$ 458	$ 123	$ 296	$ 1	$ -	$ -
Customer	TOM	OMDLTC	Cust09	$ -	$ -	$ 77,004	$ 48	$ 592	$ 16	$ 40	$ -	$ -
Total Line Transformers		OMDLTT		$ -	$ -	$ 89,584	$ 506	$ 715	$ 312	$ 41	$ -	$ -
Distribution Services												
Customer	TOM	OMDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 38	$ -	$ -	$ -
Distribution Meters												
Customer	TOM	OMDMC	MOMA	$ 151,044	$ 9,324	$ -	$ 1,702	$ 20,973	$ 792	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TOM	OMDSCL	C04	$ -	$ -	$ 2,077,842	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TOM	OMCAE	C05	$ 41,457	$ 4,146	$ 1,596,525	$ 995	$ 12,271	$ 1,658	$ 1,658	$ -	$ -
Customer Service & Info.												
Customer	TOM	OMCSI	C10	$ 260	$ 13	$ 249,951	$ 156	$ 1,921	$ 52	$ 18,630	$ -	$ 7,000
Sales Expense												
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 54,272,685	$ 23,902,778	$ 9,699,480	$ 167,482	$ 140,707	$ 22,991	$ 21,464	$ 91,514	$ 7,000

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Labor Expenses											
Power Production Plant											
Production Demand - LOLP	TLB	LBPPDB	LOLP	57,141,438	23,450,372	6,316,226	405,295	5,890,134	255,898	5,664,698	10,369,856
Production Energy	TLB	LBPPEB	E01	38,829,580	13,407,602	3,785,566	289,980	3,833,036	173,227	4,024,799	8,696,200
Total Power Production Plant		LBPPT		95,971,017	36,857,973	10,101,792	695,275	9,723,169	429,125	9,689,497	19,066,056
Transmission Plant											
Transmission Demand	TLB	LBTRB	NCPT	12,471,453	5,514,217	1,415,386	144,857	1,262,648	54,257	1,117,020	1,819,218
Distribution Poles											
Specific	TLB	LBDPS	NCPP	-	-	-	-	-	-	-	-
Distribution Substation											
General	TLB	LBDSG	NCPP	5,205,663	2,514,057	645,307	66,043	575,670	24,737	509,275	829,423
Distribution Primary & Secondary Lines											
Primary Specific	TLB	LBDPLS	NCPP	-	-	-	-	-	-	-	-
Primary Demand	TLB	LBDPLD	NCPP	4,140,341	1,999,564	513,247	52,528	457,861	19,675	405,054	659,684
Primary Customer	TLB	LBDPLC	Cust08	8,047,851	6,464,957	1,209,912	6,197	64,907	2,982	11,195	3,742
Secondary Demand	TLB	LBDSLD	SICD	1,863,918	1,543,833	287,985	20,875	-	-	-	-
Secondary Customer	TLB	LBDSLC	Cust07	3,762,788	3,025,230	566,170	2,900	30,373	-	5,239	-
Total Distribution Primary & Secondary Lines		LBDLT		17,814,899	13,033,584	2,577,314	82,499	553,140	22,656	421,488	663,426
Distribution Line Transformers											
Demand	TLB	LBDLTD	SICDT	2,717,098	1,857,291	346,457	25,113	255,971	-	218,458	-
Customer	TLB	LBDLTC	Cust09	2,257,438	1,814,949	339,667	1,740	18,222	-	3,143	-
Total Line Transformers		LBDLTT		4,974,536	3,672,240	686,124	26,853	274,193	-	221,601	-
Distribution Services											
Customer	TLB	LBDSC	C02	1,903,307	1,505,256	338,392	3,062	43,976	-	12,581	-
Distribution Meters											
Customer	TLB	LBDMC	C03	1,131,971	683,863	275,959	5,633	86,282	16,873	15,433	29,891
Distribution Street & Customer Lighting											
Customer	TLB	LBDSCL	C04	2,179,679	-	-	-	-	-	-	-
Customer Accounts Expense											
Customer	TLB	LBCAE	C05	28,207,728	18,324,149	6,858,704	175,643	919,849	42,254	793,294	265,122
Customer Service & Info.											
Customer	TLB	LBCSI	C05	3,368,178	2,188,017	818,972	20,973	109,836	5,045	94,724	31,657
Sales Expense											
Customer	TLB	LBSEC	C06	-	-	-	-	-	-	-	-
Total		LBT		173,228,432	84,293,357	23,717,949	1,220,838	13,548,762	594,947	12,874,913	22,704,793

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Labor Expenses												
Power Production Plant												
Production Demand - LOLP	TLB	LBPPDB	LOLP	$ 3,375,544	$ 1,397,808	$ 9,111	$ 331	$ 5,421	$ 698	$ 47	$ -	$ -
Production Energy	TLB	LBPPEB	E01	$ 3,026,593	$ 1,305,528	$ 271,031	$ 9,861	$ 5,397	$ 736	$ 25	$ -	$ -
Total Power Production Plant		LBPPT		$ 6,402,137	$ 2,703,336	$ 280,142	$ 10,192	$ 10,818	$ 1,434	$ 72	$ -	$ -
Transmission Plant												
Transmission Demand	TLB	LBTRB	NCPT	$ 630,865	$ 422,728	$ 85,142	$ 3,098	$ 835	$ 1,175	$ 7	$ -	$ -
Distribution Poles												
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TLB	LBDSG	NCPP	$ -	$ -	$ 38,818	$ 1,412	$ 381	$ 536	$ 3	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ -	$ -	$ 30,874	$ 1,123	$ 303	$ 426	$ 3	$ -	$ -
Primary Customer	TLB	LBDPLC	Cust08	$ -	$ -	$ 281,417	$ 175	$ 2,163	$ 58	$ 146	$ -	$ -
Secondary Demand	TLB	LBDSLD	SICD	$ -	$ -	$ 10,729	$ 390	$ 105	$ -	$ 1	$ -	$ -
Secondary Customer	TLB	LBDSLC	Cust07	$ -	$ -	$ 131,687	$ 82	$ 1,012	$ 27	$ 68	$ -	$ -
Total Distribution Primary & Secondary Lines		LBDLT		$ -	$ -	$ 454,708	$ 1,771	$ 3,583	$ 512	$ 218	$ -	$ -
Distribution Line Transformers												
Demand	TLB	LBDLTD	SICDT	$ -	$ -	$ 12,907	$ 470	$ 127	$ 303	$ 1	$ -	$ -
Customer	TLB	LBDLTC	Cust09	$ -	$ -	$ 79,004	$ 49	$ 607	$ 16	$ 41	$ -	$ -
Total Line Transformers		LBDLTT		$ -	$ -	$ 91,911	$ 519	$ 734	$ 320	$ 42	$ -	$ -
Distribution Services												
Customer	TLB	LBDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 40	$ -	$ -	$ -
Distribution Meters												
Customer	TLB	LBDMC	C03	$ 14,820	$ 915	$ -	$ 167	$ 2,058	$ 78	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TLB	LBDSCL	C04	$ -	$ -	$ 2,179,679	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TLB	LBCAE	C05	$ 20,713	$ 2,071	$ 797,644	$ 497	$ 6,131	$ 829	$ 829	$ -	$ -
Customer Service & Info.												
Customer	TLB	LBCSI	C05	$ 2,473	$ 247	$ 95,244	$ 59	$ 732	$ 99	$ 99	$ -	$ -
Sales Expense												
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 7,071,008	$ 3,129,298	$ 4,023,288	$ 17,716	$ 25,271	$ 5,022	$ 1,270	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Depreciation Expenses											
Power Production Plant											
Production Demand - LOLP	TDEPR	DEPPDB	PDEPLOLPDA	$ 288,540,356	$ 118,364,937	$ 31,880,932	$ 2,045,712	$ 29,730,245	$ 1,291,636	$ 28,592,364	$ 52,341,487
Production Energy	TDEPR	DEPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 288,540,356	$ 118,364,937	$ 31,880,932	$ 2,045,712	$ 29,730,245	$ 1,291,636	$ 28,592,364	$ 52,341,487
Transmission Plant											
Transmission Demand	TDEPR	DETRB	NCPT	$ 35,077,933	$ 15,509,606	$ 3,980,996	$ 407,432	$ 3,551,397	$ 152,606	$ 3,141,796	$ 5,116,838
Distribution Poles											
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TDEPR	DEDSG	NCPP	$ 7,353,572	$ 3,551,383	$ 911,567	$ 93,294	$ 813,197	$ 34,944	$ 719,407	$ 1,171,651
Distribution Primary & Secondary Lines											
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	5,848,688	$ 2,824,604	$ 725,018	$ 74,201	$ 646,779	$ 27,793	$ 572,183	$ 931,877
Primary Customer	TDEPR	DEDPLC	Cust08	11,368,475	$ 9,132,463	$ 1,709,134	$ 8,754	$ 91,688	$ 4,212	$ 15,815	$ 5,285
Secondary Demand	TDEPR	DEDSLD	SICD	2,632,990	$ 2,180,834	$ 406,811	$ 29,488	$ -	$ -	$ -	$ -
Secondary Customer	TDEPR	DEDSLC	Cust07	5,315,352	$ 4,273,470	$ 799,777	$ 4,096	$ 42,905	$ -	$ 7,400	$ -
Total Distribution Primary & Secondary Lines		DEDLT		$ 25,165,505	$ 18,411,371	$ 3,640,739	$ 116,539	$ 781,371	$ 32,004	$ 595,398	$ 937,162
Distribution Line Transformers											
Demand	TDEPR	DEDLTD	SICDT	$ 3,838,199	$ 2,623,628	$ 489,409	$ 35,475	$ 361,587	$ -	$ 308,596	$ -
Customer	TDEPR	DEDLTC	Cust09	3,188,880	$ 2,563,816	$ 479,816	$ 2,458	$ 25,740	$ -	$ 4,440	$ -
Total Line Transformers		DEDLTT		$ 7,027,079	$ 5,187,443	$ 969,225	$ 37,932	$ 387,327	$ -	$ 313,035	$ -
Distribution Services											
Customer	TDEPR	DEDSC	C02	$ 2,688,631	$ 2,126,340	$ 478,016	$ 4,325	$ 62,121	$ -	$ 17,772	$ -
Distribution Meters											
Customer	TDEPR	DEDMC	MDA	$ 1,599,033	$ 956,412	$ 385,941	$ 7,878	$ 120,669	$ 23,598	$ 21,583	$ 41,804
Distribution Street & Customer Lighting											
Customer	TDEPR	DEDSCL	C04	$ 3,079,037	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 370,531,145	$ 164,107,492	$ 42,247,417	$ 2,713,113	$ 35,446,328	$ 1,534,789	$ 33,401,356	$ 59,608,942

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Depreciation Expenses												
Power Production Plant												
Production Demand - LOLP	TDEPR	DEPPDB	PDEPLOLPDA	$ 17,037,942	$ 7,055,388	$ 45,987	$ 1,673	$ 27,360	$ 3,522	$ 238	$ 106,487	$ 14,444
Production Energy	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 17,037,942	$ 7,055,388	$ 45,987	$ 1,673	$ 27,360	$ 3,522	$ 238	$ 106,487	$ 14,444
Transmission Plant												
Transmission Demand	TDEPR	DETRB	NCPT	$ 1,774,409	$ 1,188,990	$ 239,476	$ 8,713	$ 2,347	$ 3,306	$ 21	$ -	$ -
Distribution Poles												
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TDEPR	DEDSG	NCPP	$ -	$ -	$ 54,835	$ 1,995	$ 538	$ 757	$ 5	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ -	$ -	$ 43,613	$ 1,587	$ 428	$ 602	$ 4	$ -	$ -
Primary Customer	TDEPR	DEDPLC	Cust08	$ -	$ -	$ 397,533	$ 248	$ 3,056	$ 83	$ 206	$ -	$ -
Secondary Demand	TDEPR	DEDSLD	SICD	$ -	$ -	$ 15,156	$ 551	$ 149	$ -	$ 1	$ -	$ -
Secondary Customer	TDEPR	DEDSLC	Cust07	$ -	$ -	$ 186,023	$ 116	$ 1,430	$ 39	$ 97	$ -	$ -
Total Distribution Primary & Secondary Lines		DEDLT		$ -	$ -	$ 642,325	$ 2,502	$ 5,061	$ 723	$ 308	$ -	$ -
Distribution Line Transformers												
Demand	TDEPR	DEDLTD	SICDT	$ -	$ -	$ 18,233	$ 663	$ 179	$ 429	$ 2	$ -	$ -
Customer	TDEPR	DEDLTC	Cust09	$ -	$ -	$ 111,602	$ 70	$ 858	$ 23	$ 58	$ -	$ -
Total Line Transformers		DEDLTT		$ -	$ -	$ 129,835	$ 733	$ 1,037	$ 452	$ 60	$ -	$ -
Distribution Services												
Customer	TDEPR	DEDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 56	$ -	$ -	$ -
Distribution Meters												
Customer	TDEPR	DEDMC	MDA	$ 20,726	$ 1,279	$ -	$ 234	$ 2,878	$ 109	$ 15,923	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ 3,079,037	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 18,833,077	$ 8,245,658	$ 4,191,495	$ 15,849	$ 39,221	$ 8,924	$ 16,555	$ 106,487	$ 14,444

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Accretion Expenses											
Power Production Plant											
Production Demand - LOLP	TACRT	ACPPDB	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	TACRT	ACPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant											
Transmission Demand	TACRT	ACTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles											
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TACRT	ACDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines											
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Customer	TACRT	ACDPLC	Cust08	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Demand	TACRT	ACDSLD	SICD	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Customer	TACRT	ACDSLC	Cust07	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers											
Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust09	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services											
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters											
Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting											
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Accretion Expenses												
Power Production Plant												
Production Demand - LOLP	TACRT	ACPPDB	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	TACRT	ACPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant												
Transmission Demand	TACRT	ACTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles												
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TACRT	ACDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Customer	TACRT	ACDPLC	Cust08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Demand	TACRT	ACDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Customer	TACRT	ACDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers												
Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services												
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector		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
Property Taxes												
Power Production Plant												
Production Demand - LOLP	PTAX	PTPPDB	PPTLOLPDA	$	22,386,637	$ 9,185,399	$ 2,474,036	$ 158,752	$ 2,307,137	$ 100,234	$ 2,218,835	$ 4,061,823
Production Energy	PTAX	PTPPEB	E01		-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$	22,386,637	$ 9,185,399	$ 2,474,036	$ 158,752	$ 2,307,137	$ 100,234	$ 2,218,835	$ 4,061,823
Transmission Plant												
Transmission Demand	PTAX	PTTRB	NCPT	$	5,118,215	$ 2,263,004	$ 580,866	$ 59,448	$ 518,184	$ 22,267	$ 458,419	$ 746,597
Distribution Poles												
Specific	PTAX	PTDPS	NCPP	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	PTAX	PTDSG	NCPP	$	1,318,249	$ 636,644	$ 163,413	$ 16,724	$ 145,779	$ 6,264	$ 128,966	$ 210,038
Distribution Primary & Secondary Lines												
Primary Specific	PTAX	PTDPLS	NCPP	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP		1,048,474	$ 506,357	$ 129,971	$ 13,302	$ 115,946	$ 4,982	$ 102,573	$ 167,054
Primary Customer	PTAX	PTDPLC	Cust08		2,037,987	$ 1,637,145	$ 306,391	$ 1,569	$ 16,437	$ 755	$ 2,835	$ 947
Secondary Demand	PTAX	PTDSLD	SICD		472,007	$ 390,951	$ 72,928	$ 5,286	$ -	$ -	$ -	$ -
Secondary Customer	PTAX	PTDSLC	Cust07		952,865	$ 766,090	$ 143,373	$ 734	$ 7,691	$ -	$ 1,327	$ -
Total Distribution Primary & Secondary Lines		PTDLT		$	4,511,333	$ 3,300,543	$ 652,663	$ 20,892	$ 140,074	$ 5,737	$ 106,735	$ 168,002
Distribution Line Transformers												
Demand	PTAX	PTDLTD	SICDT	$	688,061	$ 470,329	$ 87,735	$ 6,359	$ 64,821	$ -	$ 55,321	$ -
Customer	PTAX	PTDLTC	Cust09		571,659	$ 459,606	$ 86,015	$ 441	$ 4,614	$ -	$ 796	$ -
Total Line Transformers		PTDLTT		$	1,259,720	$ 929,935	$ 173,750	$ 6,800	$ 69,435	$ -	$ 56,117	$ -
Distribution Services												
Customer	PTAX	PTDSC	C02	$	481,982	$ 381,182	$ 85,692	$ 775	$ 11,136	$ -	$ 3,186	$ -
Distribution Meters												
Customer	PTAX	PTDMC	MPTA	$	286,653	$ 171,977	$ 69,398	$ 1,417	$ 21,698	$ 4,243	$ 3,881	$ 7,517
Distribution Street & Customer Lighting												
Customer	PTAX	PTDSCL	C04	$	551,968	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	PTAX	PTCAE	C05	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	PTAX	PTCSI	C05	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	PTAX	PTSEC	C06	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$	35,914,758	$ 16,868,683	$ 4,199,818	$ 264,808	$ 3,213,443	$ 138,746	$ 2,976,138	$ 5,193,977

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Property Taxes												
Power Production Plant												
Production Demand - LOLP	PTAX	PTPPDB	PPTLOLPDA	$ 1,322,185	$ 547,515	$ 3,569	$ 130	$ 2,123	$ 273	$ 18	$ 4,039	$ 569
Production Energy	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 1,322,185	$ 547,515	$ 3,569	$ 130	$ 2,123	$ 273	$ 18	$ 4,039	$ 569
Transmission Plant												
Transmission Demand	PTAX	PTTRB	NCPT	$ 258,904	$ 173,485	$ 34,942	$ 1,271	$ 343	$ 482	$ 3	$ -	$ -
Distribution Poles												
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	PTAX	PTDSG	NCPP	$ -	$ -	$ 9,830	$ 358	$ 96	$ 136	$ 1	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ -	$ -	$ 7,818	$ 284	$ 77	$ 108	$ 1	$ -	$ -
Primary Customer	PTAX	PTDPLC	Cust08	$ -	$ -	$ 71,264	$ 44	$ 548	$ 15	$ 37	$ -	$ -
Secondary Demand	PTAX	PTDSLD	SICD	$ -	$ -	$ 2,717	$ 99	$ 27	$ -	$ 0	$ -	$ -
Secondary Customer	PTAX	PTDSLC	Cust07	$ -	$ -	$ 33,348	$ 21	$ 256	$ 7	$ 17	$ -	$ -
Total Distribution Primary & Secondary Lines		PTDLT		$ -	$ -	$ 115,147	$ 449	$ 907	$ 130	$ 55	$ -	$ -
Distribution Line Transformers												
Demand	PTAX	PTDLTD	SICDT	$ -	$ -	$ 3,269	$ 119	$ 32	$ 77	$ 0	$ -	$ -
Customer	PTAX	PTDLTC	Cust09	$ -	$ -	$ 20,007	$ 12	$ 154	$ 4	$ 10	$ -	$ -
Total Line Transformers		PTDLTT		$ -	$ -	$ 23,275	$ 131	$ 186	$ 81	$ 11	$ -	$ -
Distribution Services												
Customer	PTAX	PTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -
Distribution Meters												
Customer	PTAX	PTDMC	MPTA	$ 3,727	$ 230	$ -	$ 42	$ 517	$ 20	$ 1,987	$ -	$ -
Distribution Street & Customer Lighting												
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ 551,968	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 1,584,815	$ 721,230	$ 738,731	$ 2,381	$ 4,173	$ 1,132	$ 2,076	$ 4,039	$ 569

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Other Taxes											
Power Production Plant											
Production Demand - LOLP	OTAX	OTPPDB	LOLP	$ 8,507,901	$ 3,491,572	$ 940,435	$ 60,345	$ 876,994	$ 38,101	$ 843,428	$ 1,543,988
Production Energy	OTAX	OTPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 8,507,901	$ 3,491,572	$ 940,435	$ 60,345	$ 876,994	$ 38,101	$ 843,428	$ 1,543,988
Transmission Plant											
Transmission Demand	OTAX	OTTRB	NCPT	$ 1,945,146	$ 860,040	$ 220,755	$ 22,593	$ 196,932	$ 8,462	$ 174,219	$ 283,740
Distribution Poles											
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	OTAX	OTDSG	NCPP	$ 500,992	$ 241,953	$ 62,104	$ 6,356	$ 55,402	$ 2,381	$ 49,013	$ 79,824
Distribution Primary & Secondary Lines											
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	398,466	$ 192,438	$ 49,395	$ 5,055	$ 44,064	$ 1,893	$ 38,982	$ 63,488
Primary Customer	OTAX	OTDPLC	Cust08	774,524	$ 622,187	$ 116,442	$ 596	$ 6,247	$ 287	$ 1,077	$ 360
Secondary Demand	OTAX	OTDSLD	SICD	179,383	$ 148,578	$ 27,716	$ 2,009	$ -	$ -	$ -	$ -
Secondary Customer	OTAX	OTDSLC	Cust07	362,130	$ 291,148	$ 54,488	$ 279	$ 2,923	$ -	$ 504	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ 1,714,504	$ 1,254,351	$ 248,040	$ 7,940	$ 53,234	$ 2,180	$ 40,564	$ 63,848
Distribution Line Transformers											
Demand	OTAX	OTDLTD	SICDT	$ 261,493	$ 178,745	$ 33,343	$ 2,417	$ 24,635	$ -	$ 21,024	$ -
Customer	OTAX	OTDLTC	Cust09	217,256	$ 174,671	$ 32,689	$ 167	$ 1,754	$ -	$ 302	$ -
Total Line Transformers		OTDLTT		$ 478,749	$ 353,416	$ 66,032	$ 2,584	$ 26,388	$ -	$ 21,327	$ -
Distribution Services											
Customer	OTAX	OTDSC	C02	$ 183,174	$ 144,866	$ 32,567	$ 295	$ 4,232	$ -	$ 1,211	$ -
Distribution Meters											
Customer	OTAX	OTDMC	C03	$ 108,941	$ 65,815	$ 26,558	$ 542	$ 8,304	$ 1,624	$ 1,485	$ 2,877
Distribution Street & Customer Lighting											
Customer	OTAX	OTDSCL	C04	$ 209,772	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 13,649,179	$ 6,412,012	$ 1,596,492	$ 100,655	$ 1,221,487	$ 52,749	$ 1,131,247	$ 1,974,276

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Other Taxes												
Power Production Plant												
Production Demand - LOLP	OTAX	OTPPDB	LOLP	$ 502,591	$ 208,122	$ 1,357	$ 49	$ 807	$ 104	$ 7	$ -	$ -
Production Energy	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 502,591	$ 208,122	$ 1,357	$ 49	$ 807	$ 104	$ 7	$ -	$ -
Transmission Plant												
Transmission Demand	OTAX	OTTRB	NCPT	$ 98,395	$ 65,932	$ 13,279	$ 483	$ 130	$ 183	$ 1	$ -	$ -
Distribution Poles												
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	OTAX	OTDSG	NCPP	$ -	$ -	$ 3,736	$ 136	$ 37	$ 52	$ 0	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ -	$ -	$ 2,971	$ 108	$ 29	$ 41	$ 0	$ -	$ -
Primary Customer	OTAX	OTDPLC	Cust08	$ -	$ -	$ 27,084	$ 17	$ 208	$ 6	$ 14	$ -	$ -
Secondary Demand	OTAX	OTDSLD	SICD	$ -	$ -	$ 1,033	$ 38	$ 10	$ -	$ 0	$ -	$ -
Secondary Customer	OTAX	OTDSLC	Cust07	$ -	$ -	$ 12,674	$ 8	$ 97	$ 3	$ 7	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ 43,761	$ 170	$ 345	$ 49	$ 21	$ -	$ -
Distribution Line Transformers												
Demand	OTAX	OTDLTD	SICDT	$ -	$ -	$ 1,242	$ 45	$ 12	$ 29	$ 0	$ -	$ -
Customer	OTAX	OTDLTC	Cust09	$ -	$ -	$ 7,603	$ 5	$ 58	$ 2	$ 4	$ -	$ -
Total Line Transformers		OTDLTT		$ -	$ -	$ 8,846	$ 50	$ 71	$ 31	$ 4	$ -	$ -
Distribution Services												
Customer	OTAX	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 4	$ -	$ -	$ -
Distribution Meters												
Customer	OTAX	OTDMC	C03	$ 1,426	$ 88	$ -	$ 16	$ 198	$ 7	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ 209,772	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 602,412	$ 274,142	$ 280,751	$ 905	$ 1,587	$ 430	$ 34	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Gain Disposition of Allowances											
Power Production Plant											
Production Demand - LOLP	GAIN	OTPPDB	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	GAIN	OTPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant											
Transmission Demand	GAIN	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles											
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines											
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Customer	GAIN	OTDPLC	Cust08	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Demand	GAIN	OTDSLD	SICD	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Customer	GAIN	OTDSLC	Cust07	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers											
Demand	GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust09	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services											
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters											
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting											
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Gain Disposition of Allowances												
Power Production Plant												
Production Demand - LOLP	GAIN	OTPPDB	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	GAIN	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant												
Transmission Demand	GAIN	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles												
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Customer	GAIN	OTDPLC	Cust08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Demand	GAIN	OTDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Customer	GAIN	OTDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers												
Demand	GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services												
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Interest											
Power Production Plant											
Production Demand - LOLP	INTLTD	INTPPDB	LOLP	$ 68,341,836	$ 28,046,922	$ 7,554,281	$ 484,738	$ 7,044,670	$ 306,057	$ 6,775,045	$ 12,402,470
Production Energy	INTLTD	INTPPEB	E01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPPT		$ 68,341,836	$ 28,046,922	$ 7,554,281	$ 484,738	$ 7,044,670	$ 306,057	$ 6,775,045	$ 12,402,470
Transmission Plant											
Transmission Demand	INTLTD	INTTRB	NCPT	$ 15,624,866	$ 6,908,489	$ 1,773,267	$ 181,484	$ 1,581,909	$ 67,976	$ 1,399,459	$ 2,279,208
Distribution Poles											
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	INTLTD	INTDSG	NCPP	$ 4,024,346	$ 1,943,545	$ 498,868	$ 51,056	$ 445,034	$ 19,123	$ 393,706	$ 641,203
Distribution Primary & Secondary Lines											
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	3,200,777	$ 1,545,805	$ 396,776	$ 40,608	$ 353,959	$ 15,210	$ 313,135	$ 509,983
Primary Customer	INTLTD	INTDPLC	Cust08	6,221,559	$ 4,997,870	$ 935,348	$ 4,791	$ 50,177	$ 2,305	$ 8,655	$ 2,892
Secondary Demand	INTLTD	INTDSLD	SICD	1,440,941	$ 1,193,493	$ 222,633	$ 16,138	$ -	$ -	$ -	$ -
Secondary Customer	INTLTD	INTDSLC	Cust07	2,908,902	$ 2,338,717	$ 437,689	$ 2,242	$ 23,480	$ -	$ 4,050	$ -
Total Distribution Primary & Secondary Lines		INTDLT		$ 13,772,180	$ 10,075,884	$ 1,992,446	$ 63,778	$ 427,616	$ 17,515	$ 325,840	$ 512,875
Distribution Line Transformers											
Demand	INTLTD	INTDLTD	SICDT	$ 2,100,509	$ 1,435,817	$ 267,836	$ 19,414	$ 197,884	$ -	$ 168,883	$ -
Customer	INTLTD	INTDLTC	Cust09	1,745,160	$ 1,403,084	$ 262,586	$ 1,345	$ 14,087	$ -	$ 2,430	$ -
Total Line Transformers		INTDLTT		$ 3,845,669	$ 2,838,902	$ 530,422	$ 20,759	$ 211,970	$ -	$ 171,313	$ -
Distribution Services											
Customer	INTLTD	INTDSC	C02	$ 1,471,391	$ 1,163,670	$ 261,601	$ 2,367	$ 33,996	$ -	$ 9,726	$ -
Distribution Meters											
Customer	INTLTD	INTDMC	C03	$ 875,094	$ 528,675	$ 213,336	$ 4,355	$ 66,702	$ 13,044	$ 11,930	$ 23,108
Distribution Street & Customer Lighting											
Customer	INTLTD	INTDSCL	C04	$ 1,685,047	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 109,640,429	$ 51,506,086	$ 12,824,222	$ 808,536	$ 9,811,898	$ 423,716	$ 9,087,020	$ 15,858,864

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Interest												
Power Production Plant												
Production Demand - LOLP	INTLTD	INTPPDB	LOLP	$ 4,037,191	$ 1,671,795	$ 10,897	$ 396	$ 6,483	$ 834	$ 56	$ -	$ -
Production Energy	INTLTD	INTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPPT		$ 4,037,191	$ 1,671,795	$ 10,897	$ 396	$ 6,483	$ 834	$ 56	$ -	$ -
Transmission Plant												
Transmission Demand	INTLTD	INTTRB	NCPT	$ 790,380	$ 529,615	$ 106,670	$ 3,881	$ 1,046	$ 1,472	$ 9	$ -	$ -
Distribution Poles												
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	INTLTD	INTDSG	NCPP	$ -	$ -	$ 30,009	$ 1,092	$ 294	$ 414	$ 3	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	$ -	$ -	$ 23,868	$ 868	$ 234	$ 329	$ 2	$ -	$ -
Primary Customer	INTLTD	INTDPLC	Cust08	$ -	$ -	$ 217,556	$ 136	$ 1,672	$ 45	$ 113	$ -	$ -
Secondary Demand	INTLTD	INTDSLD	SICD	$ -	$ -	$ 8,294	$ 302	$ 81	$ -	$ 1	$ -	$ -
Secondary Customer	INTLTD	INTDSLC	Cust07	$ -	$ -	$ 101,804	$ 63	$ 782	$ 21	$ 53	$ -	$ -
Total Distribution Primary & Secondary Lines		INTDLT		$ -	$ -	$ 351,521	$ 1,369	$ 2,770	$ 396	$ 169	$ -	$ -
Distribution Line Transformers												
Demand	INTLTD	INTDLTD	SICDT	$ -	$ -	$ 9,978	$ 363	$ 98	$ 235	$ 1	$ -	$ -
Customer	INTLTD	INTDLTC	Cust09	$ -	$ -	$ 61,076	$ 38	$ 469	$ 13	$ 32	$ -	$ -
Total Line Transformers		INTDLTT		$ -	$ -	$ 71,054	$ 401	$ 567	$ 247	$ 33	$ -	$ -
Distribution Services												
Customer	INTLTD	INTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ 31	$ -	$ -	$ -
Distribution Meters												
Customer	INTLTD	INTDMC	C03	$ 11,457	$ 707	$ -	$ 129	$ 1,591	$ 60	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ 1,685,047	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 4,839,028	$ 2,202,118	$ 2,255,198	$ 7,269	$ 12,751	$ 3,455	$ 269	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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 -- Unadjusted											
Operating Revenues											
Sales		REVUC	R01	$ 1,558,608,458	$ 611,492,797	$ 224,799,513	$ 11,901,436	$ 169,760,857	$ 9,429,915	$ 134,172,118	$ 250,417,886
Sales for Resale			Energy	8,863,601	3,060,544	864,129	66,194	874,964	39,542	918,738	1,985,075
Curtailable Service Rider				(18,634,070)							(1,032,456)
LATE PAYMENT CHARGES			LPAY	3,870,654	3,005,113	603,038	17,979	188,380	8,644	32,507	10,840
RECONNECT CHARGES			RECON	2,104,204	2,004,119	96,024	268	2,811	129	485	162
OTHER SERVICE CHARGES			MISCSERV	93,979	9,792	18,331	4,534	47,511	2,180	8,198	2,734
RENT FROM ELEC PROPERTY			RFEP	2,942,175	1,391,702	345,603	21,944	259,914	11,265	240,634	419,405
TRANSMISSION SERVICE			PLTRT	26,560,959	11,743,851	3,014,405	308,507	2,689,112	115,553	2,378,963	3,874,462
ANCILLARY SERVICES			LOLP	1,421,404	583,332	157,117	10,082	146,518	6,366	140,910	257,952
TAX REMITTANCE COMPENSATION			MISCSERV	600	63	117	29	303	14	52	17
SOLAR REC			ENERGY	90,486	31,244	8,822	676	8,932	404	9,379	20,265
RETURN CHECK CHARGES			RETURN	61,024	56,873	3,526	42	442	20	76	25
OTHER MISC REVENUES			MISCSERV	166,699	17,368	32,515	8,043	84,274	3,867	14,542	4,850
EXCESS FACILITIES CHARGES			MISCSERV	30,874	3,217	6,022	1,490	15,608	716	2,693	898
REFINED COAL LICENSE FEES			LOLP	-	-	-	-	-	-	-	-
EV CHARGING STATION RENTAL				5,191							
Total Operating Revenues		TOR		$ 1,586,186,238	$ 633,400,015	$ 229,949,160	$ 12,341,223	$ 174,079,627	$ 9,618,615	$ 137,919,298	$ 255,962,116
Operating Expenses											
Operation and Maintenance Expenses				$ 892,295,073	$ 369,164,547	$ 102,781,777	$ 6,577,503	$ 80,222,463	$ 3,699,084	$ 80,149,961	$ 161,373,638
Depreciation and Amortization Expenses				370,531,145	164,107,492	42,247,417	2,713,113	35,446,328	1,534,789	33,401,356	59,608,942
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-	-
Property Taxes			NPT	35,914,758	16,868,683	4,199,818	264,808	3,213,443	138,746	2,976,138	5,193,977
Other Taxes				13,649,179	6,412,012	1,596,492	100,655	1,221,487	52,749	1,131,247	1,974,276
Gain Disposition of Allowances				-	-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	23,821,553	$ 3,677,404	$ 9,621,085	$ 272,325	$ 6,408,888	$ 547,018	$ 1,621,461	$ 1,734,483
Total Operating Expenses		TOE		$ 1,336,211,708	$ 560,230,138	$ 160,446,589	$ 9,928,404	$ 126,512,609	$ 5,972,385	$ 119,280,162	$ 229,885,316
Net Operating Income (Unadjusted)		TOM		$ 249,974,531	$ 73,169,877	$ 69,502,571	$ 2,412,819	$ 47,567,018	$ 3,646,230	$ 18,639,136	$ 26,076,800
Net Cost Rate Base				$ 5,197,832,023	$ 2,457,262,896	$ 610,215,074	$ 38,745,077	$ 458,917,674	$ 19,889,476	$ 424,876,670	$ 740,522,922
Taxable Income Unadjusted											
Total Operating Revenue				$ 1,586,186,238	$ 633,400,015	$ 229,949,160	$ 12,341,223	$ 174,079,627	$ 9,618,615	$ 137,919,298	$ 255,962,116
Operating Expenses				$ 1,312,390,155	$ 556,552,735	$ 150,825,504	$ 9,656,079	$ 120,103,721	$ 5,425,367	$ 117,658,701	$ 228,150,833
Interest Expense		INTEXP		$ 109,640,429	$ 51,506,086	$ 12,824,222	$ 808,536	$ 9,811,898	$ 423,716	$ 9,087,020	$ 15,858,864
Taxable Income		TAXINC		$ 164,155,654	$ 25,341,194	$ 66,299,434	$ 1,876,608	$ 44,164,008	$ 3,769,533	$ 11,173,577	$ 11,952,419

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Cost of Service Summary -- Unadjusted												
Operating Revenues												
Sales		REVUC	R01	$ 82,247,981	$ 32,956,814	$ 30,555,893	$ 307,246	$ 271,291	$ 92,320	$ 1,533	$ 162,504	$ 38,355
Sales for Resale			Energy	690,878	298,012	61,868	2,251	1,232	168	6	-	-
Curtailable Service Rider				(3,386,120)	(14,215,494)							
LATE PAYMENT CHARGES			LPAY	848	42	3,262	-	-	-	-	-	-
RECONNECT CHARGES			RECON	13	1	193	-	-	-	-	-	-
OTHER SERVICE CHARGES			MISCSERV	214	11	474	-	-	-	-	-	-
RENT FROM ELEC PROPERTY			RFEP	127,744	59,097	64,194	226	349	99	-	-	-
TRANSMISSION SERVICE			PLTRT	1,343,580	900,302	181,331	6,597	1,777	2,503	16	-	-
ANCILLARY SERVICES			LOLP	83,967	34,771	227	8	135	17	1	-	-
TAX REMITTANCE COMPENSATION			MISCSERV	1	0	3	-	-	-	-	-	-
SOLAR REC			ENERGY	7,053	3,042	632	23	13	2	0	-	-
RETURN CHECK CHARGES			RETURN	2	0	18	-	-	-	-	-	-
OTHER MISC REVENUES			MISCSERV	380	19	841	-	-	-	-	-	-
EXCESS FACILITIES CHARGES			MISCSERV	70	4	156	-	-	-	-	-	-
REFINED COAL LICENSE FEES			LOLP	-	-	-	-	-	-	-	-	-
EV CHARGING STATION RENTAL										5,191		
Total Operating Revenues		TOR		$ 81,116,612	$ 20,036,620	$ 30,869,092	$ 316,351	$ 274,796	$ 95,109	$ 6,746	$ 162,504	$ 38,355
Operating Expenses												
Operation and Maintenance Expenses				$ 54,272,685	$ 23,902,778	$ 9,699,480	$ 167,482	$ 140,707	$ 22,991	$ 21,464	$ 91,514	$ 7,000
Depreciation and Amortization Expenses				18,833,077	8,245,658	4,191,495	15,849	39,221	8,924	16,555	106,487	14,444
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-	-	-
Property Taxes			NPT	1,584,815	721,230	738,731	2,381	4,173	1,132	2,076	4,039	569
Other Taxes				602,412	274,142	280,751	905	1,587	430	34	-	-
Gain Disposition of Allowances				-	-	-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 142,880	$ (2,221,620)	$ 1,988,583	$ 17,772	$ 11,081	$ 8,443	$ (4,883)	$ (5,737)	$ 2,371
Total Operating Expenses		TOE		$ 75,435,869	$ 30,922,189	$ 16,899,039	$ 204,388	$ 196,768	$ 41,919	$ 35,245	$ 196,303	$ 24,385
Net Operating Income (Unadjusted)		TOM		$ 5,680,743	$ (10,885,569)	$ 13,970,052	$ 111,963	$ 78,028	$ 53,190	$ (28,498)	$ (33,799)	$ 13,970
Net Cost Rate Base				$ 225,552,349	$ 104,343,933	$ 113,343,713	$ 398,777	$ 615,338	$ 174,679	$ 105,539	$ 2,576,969	$ 290,934
Taxable Income Unadjusted												
Total Operating Revenue				$ 81,116,612	$ 20,036,620	$ 30,869,092	$ 316,351	$ 274,796	$ 95,109	$ 6,746	$ 162,504	$ 38,355
Operating Expenses				$ 75,292,989	$ 33,143,809	$ 14,910,456	$ 186,617	$ 185,688	$ 33,476	$ 40,128	$ 202,040	$ 22,013
Interest Expense		INTEXP		$ 4,839,028	$ 2,202,118	$ 2,255,198	$ 7,269	$ 12,751	$ 3,455	$ 269	$ -	$ -
Taxable Income		TAXINC		$ 984,595	$ (15,309,306)	$ 13,703,437	$ 122,466	$ 76,358	$ 58,178	$ (33,651)	$ (39,536)	$ 16,342

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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				$ 1,586,186,238	$ 633,400,015	$ 229,949,160	$ 12,341,223	$ 174,079,627	$ 9,618,615	$ 137,919,298	$ 255,962,116
Operating Expenses											
Operation and Maintenance Expenses				$ 892,295,073	$ 369,164,547	$ 102,781,777	$ 6,577,503	$ 80,222,463	$ 3,699,084	$ 80,149,961	$ 161,373,638
Depreciation and Amortization Expenses				370,531,145	164,107,492	42,247,417	2,713,113	35,446,328	1,534,789	33,401,356	59,608,942
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-	-
Property Taxes			NPT	35,914,758	16,868,683	4,199,818	264,808	3,213,443	138,746	2,976,138	5,193,977
Other Taxes				13,649,179	6,412,012	1,596,492	100,655	1,221,487	52,749	1,131,247	1,974,276
Gain Disposition of Allowances				-	-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	23,821,553	$ 3,677,404	$ 9,621,085	$ 272,325	$ 6,408,888	$ 547,018	$ 1,621,461	$ 1,734,483
Specific Assignment of Curtailable Service Rider Credit				(18,634,070)	-	-	-	-	-	-	(1,032,456)
Total Operating Expenses		TOE		$ 1,336,211,708	$ 567,877,412	$ 162,506,339	$ 10,060,573	$ 128,433,409	$ 6,055,835	$ 121,127,446	$ 232,234,517
Net Operating Income (Adjusted)				$ 249,974,531	$ 65,522,603	$ 67,442,821	$ 2,280,650	$ 45,646,218	$ 3,562,781	$ 16,791,852	$ 23,727,598
Adjusted Net Cost Rate Base				$ 5,197,832,023	$ 2,457,262,896	$ 610,215,074	$ 38,745,077	$ 458,917,674	$ 19,889,476	$ 424,876,670	$ 740,522,922
Rate of Return				**4.81%**	**2.67%**	**11.05%**	**5.89%**	**9.95%**	**17.91%**	**3.95%**	**3.20%**
Taxable Income Pro-Forma											
Total Operating Revenue				$ 1,586,186,238	$ 633,400,015	$ 229,949,160	$ 12,341,223	$ 174,079,627	$ 9,618,615	$ 137,919,298	$ 255,962,116
Operating Expenses				$ 1,312,390,155	$ 564,200,009	$ 152,885,255	$ 9,788,247	$ 122,024,520	$ 5,508,817	$ 119,505,985	$ 230,500,035
Interest Expense		INTEXP		$ 109,640,429	$ 51,506,086	$ 12,824,222	$ 808,536	$ 9,811,898	$ 423,716	$ 9,087,020	$ 15,858,864
Interest Syncronization Adjustment			INTEXP	$ 6,243,936	$ 2,933,231	$ 730,329	$ 46,045	$ 558,780	$ 24,130	$ 517,499	$ 903,150
Taxable Income		TXINCPF		$ 157,911,719	$ 14,760,689	$ 63,509,354	$ 1,698,394	$ 41,684,429	$ 3,661,953	$ 8,808,794	$ 8,700,067

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Cost of Service Summary -- Pro-Forma												
Operating Revenues												
Total Pro-Forma Operating Revenue				$ 81,116,612	$ 20,036,620	$ 30,869,092	$ 316,351	$ 274,796	$ 95,109	$ 6,746	$ 162,504	$ 38,355
Operating Expenses												
Operation and Maintenance Expenses				$ 54,272,685	$ 23,902,778	$ 9,699,480	$ 167,482	$ 140,707	$ 22,991	$ 21,464	$ 91,514	$ 7,000
Depreciation and Amortization Expenses				18,833,077	8,245,658	4,191,495	15,849	39,221	8,924	16,555	106,487	14,444
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-	-	-
Property Taxes			NPT	1,584,815	721,230	738,731	2,381	4,173	1,132	2,076	4,039	569
Other Taxes				602,412	274,142	280,751	905	1,587	430	34	-	-
Gain Disposition of Allowances				-	-	-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 142,880	$ (2,221,620)	$ 1,988,583	$ 17,772	$ 11,081	$ 8,443	$ (4,883)	$ (5,737)	$ 2,371
Specific Assignment of Curtailable Service Rider Credit				(3,386,120)	(14,215,494)	-	-	-	-	-	-	-
Total Operating Expenses		TOE		$ 73,150,529	$ 17,162,527	$ 16,902,010	$ 204,496	$ 198,536	$ 42,146	$ 35,245	$ 196,303	$ 24,385
Net Operating Income (Adjusted)				$ 7,966,082	$ 2,874,093	$ 13,967,081	$ 111,854	$ 76,260	$ 52,963	$ (28,498)	$ (33,799)	$ 13,970
Adjusted Net Cost Rate Base				$ 225,552,349	$ 104,343,933	$ 113,343,713	$ 398,777	$ 615,338	$ 174,679	$ 105,539	$ 2,576,969	$ 290,934
Rate of Return				**3.53%**	**2.75%**	**12.32%**	**28.05%**	**12.39%**	**30.32%**	**-27.00%**	**-1.31%**	**4.80%**
Taxable Income Pro-Forma												
Total Operating Revenue				$ 81,116,612	$ 20,036,620	$ 30,869,092	$ 316,351	$ 274,796	$ 95,109	$ 6,746	$ 162,504	$ 38,355
Operating Expenses				$ 73,007,649	$ 19,384,147	$ 14,913,427	$ 186,725	$ 187,455	$ 33,704	$ 40,128	$ 202,040	$ 22,013
Interest Expense		INTEXP		$ 4,839,028	$ 2,202,118	$ 2,255,198	$ 7,269	$ 12,751	$ 3,455	$ 269	$ -	$ -
Interest Syncronization Adjustment			INTEXP	$ 275,579	$ 125,409	$ 128,432	$ 414	$ 726	$ 197	$ 15	$ -	$ -
Taxable Income		TXINCPF		$ 2,994,356	$ (1,675,053)	$ 13,572,034	$ 121,944	$ 73,864	$ 57,754	$ (33,666)	$ (39,536)	$ 16,342

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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 -- Adjusted for Proposed Increase											
Operating Revenue											
Total Operating Revenue				$ 1,586,186,238	$ 633,400,015	$ 229,949,160	$ 12,341,223	$ 174,079,627	$ 9,618,615	$ 137,919,298	$ 255,962,116
Proposed Increase				$ 169,747,179	$ 68,196,266	$ 26,734,943	$ 1,453,830	$ 18,553,034	$ 1,039,687	$ 14,530,948	$ 26,942,083
Revenue Adjustment for Solar Share and EV				$ 353,856	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes to EVSE-R					$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes in Other Service Revenues			MISCSERV	$ 366,528	$ 38,188	$ 71,491	$ 17,684	$ 185,297	$ 8,503	$ 31,975	$ 10,663
Changes in Miscellaneous Charges			MISCSERV	$ 5,899	$ 615	$ 1,151	$ 285	$ 2,982	$ 137	$ 515	$ 172
Total Pro-Forma Operating Revenue				$ 1,756,659,700	$ 701,635,083	$ 256,756,745	$ 13,813,022	$ 192,820,941	$ 10,666,942	$ 152,482,735	$ 282,915,033
Operating Expenses											
Total Operating Expenses				$ 1,336,211,708	$ 567,877,412	$ 162,506,339	$ 10,060,573	$ 128,433,409	$ 6,055,835	$ 121,127,446	$ 232,234,517
Pro-Forma Adjustments											
Increase in Uncollectible Expense			0.316%	$ 538,696	$ 215,623	$ 84,712	$ 4,651	$ 59,223	$ 3,313	$ 46,020	$ 85,171
Increase in PSC Fees			0.200%	$ 340,947	$ 136,470	$ 53,615	$ 2,944	$ 37,483	$ 2,097	$ 29,127	$ 53,906
Incremental Income Taxes			24.83%	$ 42,323,441	$ 16,940,718	$ 6,655,518	$ 365,403	$ 4,652,905	$ 260,268	$ 3,615,664	$ 6,691,600
Total Pro-Forma Operating Expenses				$ 1,379,414,792	$ 585,170,224	$ 169,300,185	$ 10,433,571	$ 133,183,019	$ 6,321,512	$ 124,818,257	$ 239,065,194
Net Operating Income				$ 377,244,908	$ 116,464,860	$ 87,456,560	$ 3,379,451	$ 59,637,921	$ 4,345,430	$ 27,664,478	$ 43,849,839
Net Cost Rate Base				$ 5,197,832,023	$ 2,457,262,896	$ 610,215,074	$ 38,745,077	$ 458,917,674	$ 19,889,476	$ 424,876,670	$ 740,522,922
Rate of Return				7.26%	4.74%	14.33%	8.72%	13.00%	21.85%	6.51%	5.92%

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Cost of Service Summary -- Adjusted for Proposed Increase												
Operating Revenue												
Total Operating Revenue				$ 81,116,612	$ 20,036,620	$ 30,869,092	$ 316,351	$ 274,796	$ 95,109	$ 6,746	$ 162,504	$ 38,355
Proposed Increase				$ 8,787,141	$ 3,514,118	$ (129)	$ 18	$ 2	$ (4,762)	$ -	$ -	$ -
Revenue Adjustment for Solar Share and EV				$ -	$ -	$ -	$ -	$ -	$ -	$ 48,431	$ 295,846	$ 9,579
Changes to EVSE-R				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Changes in Other Service Revenues			MISCSERV	$ 835	$ 42	$ 1,850	$ -	$ -	$ -	$ -	$ -	$ -
Changes in Miscellaneous Charges			MISCSERV	$ 13	$ 1	$ 30	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 89,904,600	$ 23,550,780	$ 30,870,843	$ 316,369	$ 274,798	$ 90,347	$ 55,178	$ 458,350	$ 47,934
Operating Expenses												
Total Operating Expenses				$ 73,150,529	$ 17,162,527	$ 16,902,010	$ 204,496	$ 198,536	$ 42,146	$ 35,245	$ 196,303	$ 24,385
Pro-Forma Adjustments												
Increase in Uncollectible Expense			0.316%	$ 27,770	$ 11,105	$ 6	$ 0	$ 0	$ (15)	$ 153	$ 935	$ 30
Increase in PSC Fees			0.200%	$ 17,576	$ 7,028	$ 4	$ 0	$ 0	$ (10)	$ 97	$ 592	$ 19
Incremental Income Taxes			24.83%	$ 2,181,794	$ 872,460	$ 435	$ 4	$ 0	$ (1,182)	$ 12,024	$ 73,450	$ 2,378
Total Pro-Forma Operating Expenses				$ 75,377,669	$ 18,053,120	$ 16,902,454	$ 204,501	$ 198,536	$ 40,939	$ 47,519	$ 271,279	$ 26,812
Net Operating Income				$ 14,526,931	$ 5,497,660	$ 13,968,388	$ 111,868	$ 76,262	$ 49,408	$ 7,659	$ 187,071	$ 21,121
Net Cost Rate Base				$ 225,552,349	$ 104,343,933	$ 113,343,713	$ 398,777	$ 615,338	$ 174,679	$ 105,539	$ 2,576,969	$ 290,934
Rate of Return				**6.44%**	**5.27%**	**12.32%**	**28.05%**	**12.39%**	**28.28%**	**7.26%**	**7.26%**	**7.26%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Allocation Factors											
Energy Allocation Factors											
Energy Usage by Class		E01	Energy	1.000000	0.345294	0.097492	0.007468	0.098714	0.004461	0.103653	0.223958
Customer Allocation Factors											
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	1.000000	0.80331	0.15034	0.00077	0.00807	0.00037	0.00139	0.00046
Customer Services -- Weighted cost of Services		C02		1.000000	0.790864	0.177792	0.001609	0.023105	-	0.006610	-
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.604135	0.243786	0.004976	0.076223	0.014906	0.013633	0.026406
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.64961	0.24315	0.00623	0.03261	0.00150	0.02812	0.00940
Marketing/Economic Development		C06	Cust06	1.000000	0.80328	0.15033	0.00077	0.00806	0.00037	0.00139	0.00046
Total billed revenue per Billing Determinants		R01		1,558,608,458	611,492,797	224,799,513	11,901,436	169,760,857	9,429,915	134,172,118	250,417,886
Energy (at the Meter)				17,402,124,383	5,943,619,831	1,678,149,896	128,548,999	1,699,193,305	78,721,459	1,784,202,424	3,951,918,371
Energy (Loss Adjusted)(at Source)		Energy		18,429,987,351	6,363,754,932	1,796,772,839	137,635,708	1,819,303,738	82,219,916	1,910,321,874	4,127,545,429
O&M Customer Allocators											
Customers (Monthly Bills)				8,471,803	5,308,105	993,413	5,086	53,288	2,445	9,195	3,066
Average Customers (Bills/12)				705,984	442,342	82,784	424	4,441	204	766	256
Average Customers (Lighting = Lights)				705,984	442,342	82,784	424	4,441	204	766	256
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		680,930	442,342	165,568	4,240	22,205	1,020	19,150	6,400
Street Lighting		Cust04		143,087,299	-	-	-	-	-	-	-
Average Customers		Cust01		705,984	442,342	82,784	424	4,441	204	766	256
Average Customers (Lighting = 9 Lights per Cust)		Cust06		550,667	442,342	82,784	424	4,441	204	766	256
Average Secondary Customers		Cust07		550,186	442,342	82,784	424	4,441	-	766	-
Average Primary Customers		Cust08		550,646	442,342	82,784	424	4,441	204	766	256
Average Transformer Customers		Cust09		550,186	442,342	82,784	424	4,441	-	766	-
Plant Customer Allocators											
Average Customers				705,871	442,270	82,743	424	4,442	204	765	256
Average Customers (Lighting = Lights)				705,871	442,270	82,743	424	4,442	204	765	256
Weighted Average Customers (Lighting =9 Lights per Cu		PCust05		680,755	442,270	165,485	4,240	22,210	1,020	19,125	6,400
Street Lighting		PCust04		143,087,299	-	-	-	-	-	-	-
Average Customers		PCust01		705,871	442,270	82,743	424	4,442	204	765	256
Average Customers (Lighting = 9 Lights per Cust)		PCust06		550,553	442,270	82,743	424	4,442	204	765	256
Average Secondary Customers		PCust07		544,871	442,270	82,743	424	-	-	-	-
Average Primary Customers		PCust08		550,532	442,270	82,743	424	4,442	204	765	256
Average Transformer Customers		PCust09		550,072	442,270	82,743	424	4,442	-	765	-
Demand Allocators											
Maximum Class Non-Coincident Peak Demands (Transm		NCPT		4,393,697	1,942,660	498,641	51,033	444,831	19,115	393,527	640,911
Maximum Class Non-Coincident Peak Demands (Primary		NCPP		4,022,516	1,942,660	498,641	51,033	444,831	19,115	393,527	640,911
Sum of the Individual Customer Demands (Transformer)		SICDT		6,314,351	4,316,218	805,143	58,361	594,859	-	507,681	-
Sum of the Individual Customer Demands (Secondary)		SICD		5,211,105	4,316,218	805,143	58,361	-	-	-	-
LOLP Demand Allocator		LOLP		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Allocation Factors												
Energy Allocation Factors												
Energy Usage by Class		E01	Energy	0.077946	0.033622	0.006980	0.000254	0.000139	0.000019	0.000001	-	-
Customer Allocation Factors												
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	-	-	0.03497	0.00002	0.00027	0.00001	0.00002	-	-
Customer Services -- Weighted cost of Services		C02		-	-	-	-	-	0.000021	-	-	-
Meter Costs -- Weighted Cost of Meters		C03		0.013092	0.000808	-	0.000148	0.001818	0.000069	-	-	-
Lighting Systems -- Lighting Customers		C04	Cust04	-	-	1.00000	-	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.00073	0.00007	0.02828	0.00002	0.00022	0.00003	0.00003	-	-
Marketing/Economic Development		C06	Cust06	0.00004	0.00000	0.03497	0.00002	0.00027	0.00001	0.00002	-	-
Total billed revenue per Billing Determinants		R01		82,247,981	32,956,814	30,555,893	307,246	271,291	92,320	1,533	162,504	38,355
Energy (at the Meter)				1,404,629,847	605,890,405	120,148,466	4,371,371	2,392,654	326,405	10,950	-	-
Energy (Loss Adjusted)(at Source)		Energy		1,436,535,296	619,652,896	128,641,369	4,680,369	2,561,783	349,478	11,724	-	-
O&M Customer Allocators												
Customers (Monthly Bills)				240	12	2,079,516	1,296	15,972	48	120	-	-
Average Customers (Bills/12)				20	1	173,293	108	1,331	4	10	-	-
Average Customers (Lighting = Lights)				20	1	173,293	108	1,331	4	10	-	-
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		500	50	19,255	12	148	20	20	-	-
Street Lighting		Cust04		-	-	143,087,299	-	-	-	-		-
Average Customers		Cust01		20	1	173,293	108	1,331	4	10	-	-
Average Customers (Lighting = 9 Lights per Cust)		Cust06		20	1	19,255	12	148	4	10	-	-
Average Secondary Customers		Cust07		-	-	19,255	12	148	4	10	-	-
Average Primary Customers		Cust08		-	-	19,255	12	148	4	10	-	-
Average Transformer Customers		Cust09		-	-	19,255	12	148	4	10	-	-
Plant Customer Allocators												
Average Customers				20	1	173,293	108	1,331	4	10	-	-
Average Customers (Lighting = Lights)				20	1	173,293	108	1,331	4	10	-	-
Weighted Average Customers (Lighting =9 Lights per Cu		PCust05		500	50	19,255	12	148	20	20	-	-
Street Lighting		PCust04		-	-	143,087,299	-	-	-	-	-	-
Average Customers		PCust01		20	1	173,293	108	1,331	4	10	-	-
Average Customers (Lighting = 9 Lights per Cust)		PCust06		20	1	19,255	12	148	4	10	-	-
Average Secondary Customers		PCust07		-	-	19,255	12	148	-	20	-	-
Average Primary Customers		PCust08		-	-	19,255	12	148	4	10	-	-
Average Transformer Customers		PCust09		-	-	19,255	12	148	4	10	-	-
Demand Allocators												
Maximum Class Non-Coincident Peak Demands (Transm		NCPT		222,254	148,927	29,996	1,091	294	414	3	-	-
Maximum Class Non-Coincident Peak Demands (Primary		NCPP		-	-	29,996	1,091	294	414	3	-	-
Sum of the Individual Customer Demands (Transformer)		SICDT		-	-	29,996	1,091	294	705	3	-	-
Sum of the Individual Customer Demands (Secondary)		SICD		-	-	29,996	1,091	294	-	3	-	-
LOLP Demand Allocator		LOLP		145,533	60,265	393	14	234	30	2	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Production Demand Cost Allocation											
Gross Plant Production Residual LOLP Demand Allocato		GPPLOLPDRA		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085
Gross Plant Production LOLP Demand Costs				$ 6,073,014,123							
Customer Specific Assignment				$ 3,728,601							
Gross Plant Production LOLP Demand Residual			GPPLOLPDRA	$ 6,069,285,522	$ 2,490,784,384	$ 670,878,802	$ 43,048,460	$ 625,621,337	$ 27,180,233	$ 601,676,613	$ 1,101,435,630
Gross Plant Production LOLP Demand Total		GPPLOLPDT		$ 6,073,014,123	$ 2,490,784,384	$ 670,878,802	$ 43,048,460	$ 625,621,337	$ 27,180,233	$ 601,676,613	$ 1,101,435,630
Gross Plant Production LOLP Demand Allocator		GPLOLPDA	GPPLOLPDT	1.000000	0.41014	0.11047	0.00709	0.10302	0.00448	0.09907	0.18137
Net Production Residual LOLP Demand Allocator		NPPLOLPDRA		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085
Net Production LOLP Demand Costs				$ 3,680,027,941							
Customer Specific Assignment				$ 3,513,380							
Net Production LOLP Demand Residual			NPPLOLPDRA	$ 3,676,514,562	$ 1,508,811,050	$ 406,389,793	$ 26,076,923	$ 378,974,749	$ 16,464,627	$ 364,470,055	$ 667,202,773
Net Production LOLP Demand Total		NPPLOLPDT		$ 3,680,027,941	$ 1,508,811,050	$ 406,389,793	$ 26,076,923	$ 378,974,749	$ 16,464,627	$ 364,470,055	$ 667,202,773
Net Production LOLP Demand Allocator		NPLOLPDA	NPPLOLPDT	1.000000	0.41000	0.11043	0.00709	0.10298	0.00447	0.09904	0.18130
Rate Base Production Residual LOLP Demand Allocator		RBLOLPDRA		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085
Rate Base Production LOLP Demand Costs				$ 2,975,438,420							
Customer Specific Assignment				$ 2,867,904							
Rate Base Production LOLP Demand Residual			RBLOLPDRA	$ 2,972,570,516	$ 1,219,918,258	$ 328,578,140	$ 21,083,962	$ 306,412,268	$ 13,312,137	$ 294,684,795	$ 539,453,131
Rate Base Production LOLP Demand Total		RBLOLPDT		$ 2,975,438,420	$ 1,219,918,258	$ 328,578,140	$ 21,083,962	$ 306,412,268	$ 13,312,137	$ 294,684,795	$ 539,453,131
Rate Base Production LOLP Demand Allocator		RBLOLPDA	RBLOLPDT	1.000000	0.41000	0.11043	0.00709	0.10298	0.00447	0.09904	0.18130
Production O&M Residual LOLP Demand Allocator		POMLOLPDRA		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085
Production O&M LOLP Demand Costs				$ 133,195,931							
Customer Specific Assignment				$ 91,514							
Production O&M LOLP Demand Residual			POMLOLPDRA	$ 133,104,417	$ 54,624,948	$ 14,712,923	$ 944,088	$ 13,720,390	$ 596,085	$ 13,195,262	$ 24,155,388
Production O&M LOLP Demand Total		POMLOLPDT		$ 133,195,931	$ 54,624,948	$ 14,712,923	$ 944,088	$ 13,720,390	$ 596,085	$ 13,195,262	$ 24,155,388
Production O&M LOLP Demand Allocator		POMLOLPD/	POMLOLPDT	1.000000	0.41011	0.11046	0.00709	0.10301	0.00448	0.09907	0.18135
Production Depreciation Residual LOLP Demand Allocat		PDEPLOLPDRA		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085
Production Depreciation LOLP Demand Costs				$ 288,540,356							
Customer Specific Assignment				$ 120,931							
Production Depreciation LOLP Demand Residual			PDEPLOLPDRA	$ 288,419,425	$ 118,364,937	$ 31,880,932	$ 2,045,712	$ 29,730,245	$ 1,291,636	$ 28,592,364	$ 52,341,487
Production Depreciation LOLP Demand Total		PDEPLOLPDT		$ 288,540,356	$ 118,364,937	$ 31,880,932	$ 2,045,712	$ 29,730,245	$ 1,291,636	$ 28,592,364	$ 52,341,487
Production Depreciation LOLP Demand Allocator		PDEPLOLPD	PDEPLOLPDT	1.000000	0.41022	0.11049	0.00709	0.10304	0.00448	0.09909	0.18140
Production Prop Tax Residual LOLP Demand Allocator		PPTLOLPDRA		2,463,591	1,011,037	272,317	17,474	253,947	11,033	244,227	447,085
Production Prop Tax LOLP Demand Costs				$ 22,386,637							
Customer Specific Assignment				$ 4,608							
Production Prop Tax LOLP Demand Residual			PPTLOLPDRA	$ 22,382,029	$ 9,185,399	$ 2,474,036	$ 158,752	$ 2,307,137	$ 100,234	$ 2,218,835	$ 4,061,823
Production Prop Tax LOLP Demand Total		PPTLOLPDT		$ 22,386,637	$ 9,185,399	$ 2,474,036	$ 158,752	$ 2,307,137	$ 100,234	$ 2,218,835	$ 4,061,823
Production Prop Tax LOLP Demand Allocator		PPTLOLPDA	PPTLOLPDT	1.000000	0.41031	0.11051	0.00709	0.10306	0.00448	0.09911	0.18144

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Production Demand Cost Allocation												
Gross Plant Production Residual LOLP Demand Allocato		GPPLOLPDRA		145,533	60,265	393	14	234	30	2	-	-
Gross Plant Production LOLP Demand Costs												-
Customer Specific Assignment											$ 3,325,058	$ 403,543
Gross Plant Production LOLP Demand Residual			GPPLOLPDRA	$ 358,533,878	$ 148,468,386	$ 967,726	$ 35,209	$ 575,745	$ 74,108	$ 5,011	$ -	$ -
Gross Plant Production LOLP Demand Total		GPPLOLPDT		$ 358,533,878	$ 148,468,386	$ 967,726	$ 35,209	$ 575,745	$ 74,108	$ 5,011	$ 3,325,058	$ 403,543
Gross Plant Production LOLP Demand Allocator		GPLOLPDA	GPPLOLPDT	0.05904	0.02445	0.00016	0.00001	0.00009	0.00001	0.00000	0.00055	0.00007
Net Production Residual LOLP Demand Allocator		NPPLOLPDRA		145,533	60,265	393	14	234	30	2	-	-
Net Production LOLP Demand Costs												
Customer Specific Assignment											$ 3,141,953	$ 371,427
Net Production LOLP Demand Residual			NPPLOLPDRA	$ 217,184,547	$ 89,935,822	$ 586,207	$ 21,328	$ 348,762	$ 44,892	$ 3,036	$ -	$ -
Net Production LOLP Demand Total		NPPLOLPDT		$ 217,184,547	$ 89,935,822	$ 586,207	$ 21,328	$ 348,762	$ 44,892	$ 3,036	$ 3,141,953	$ 371,427
Net Production LOLP Demand Allocator		NPLOLPDA	NPPLOLPDT	0.05902	0.02444	0.00016	0.00001	0.00009	0.00001	0.00000	0.00085	0.00010
Rate Base Production Residual LOLP Demand Allocator		RBLOLPDRA		145,533	60,265	393	14	234	30	2	-	-
Rate Base Production LOLP Demand Costs												
Customer Specific Assignment											$ 2,576,969	$ 290,934
Rate Base Production LOLP Demand Residual			RBLOLPDRA	$ 175,600,115	$ 72,715,766	$ 473,966	$ 17,244	$ 281,984	$ 36,296	$ 2,454	$ -	$ -
Rate Base Production LOLP Demand Total		RBLOLPDT		$ 175,600,115	$ 72,715,766	$ 473,966	$ 17,244	$ 281,984	$ 36,296	$ 2,454	$ 2,576,969	$ 290,934
Rate Base Production LOLP Demand Allocator		RBLOLPDA	RBLOLPDT	0.05902	0.02444	0.00016	0.00001	0.00009	0.00001	0.00000	0.00087	0.00010
Production O&M Residual LOLP Demand Allocator		POMLOLPDRA		145,533	60,265	393	14	234	30	2	-	-
Production O&M LOLP Demand Costs												0
Customer Specific Assignment											$ 91,514	
Production O&M LOLP Demand Residual			POMLOLPDRA	$ 7,862,942	$ 3,256,034	$ 21,223	$ 772	$ 12,627	$ 1,625	$ 110	$ -	$ -
Production O&M LOLP Demand Total		POMLOLPDT		$ 7,862,942	$ 3,256,034	$ 21,223	$ 772	$ 12,627	$ 1,625	$ 110	$ 91,514	$ -
Production O&M LOLP Demand Allocator		POMLOLPD/	POMLOLPDT	0.05903	0.02445	0.00016	0.00001	0.00009	0.00001	0.00000	0.00069	-
Production Depreciation Residual LOLP Demand Allocat		PDEPLOLPDRA		145,533	60,265	393	14	234	30	2	-	-
Production Depreciation LOLP Demand Costs												-
Customer Specific Assignment											$ 106,487	$ 14,444
Production Depreciation LOLP Demand Residual			PDEPLOLPDRA	$ 17,037,942	$ 7,055,388	$ 45,987	$ 1,673	$ 27,360	$ 3,522	$ 238	$ -	$ -
Production Depreciation LOLP Demand Total		PDEPLOLPDT		$ 17,037,942	$ 7,055,388	$ 45,987	$ 1,673	$ 27,360	$ 3,522	$ 238	$ 106,487	$ 14,444
Production Depreciation LOLP Demand Allocator		PDEPLOLPD	PDEPLOLPDT	0.05905	0.02445	0.00016	0.00001	0.00009	0.00001	0.00000	0.00037	0.00005
Production Prop Tax Residual LOLP Demand Allocator		PPTLOLPDRA		145,533	60,265	393	14	234	30	2	-	-
Production Prop Tax LOLP Demand Costs												0
Customer Specific Assignment											$ 4,039	$ 569
Production Prop Tax LOLP Demand Residual			PPTLOLPDRA	$ 1,322,185	$ 547,515	$ 3,569	$ 130	$ 2,123	$ 273	$ 18	$ -	$ -
Production Prop Tax LOLP Demand Total		PPTLOLPDT		$ 1,322,185	$ 547,515	$ 3,569	$ 130	$ 2,123	$ 273	$ 18	$ 4,039	$ 569
Production Prop Tax LOLP Demand Allocator		PPTLOLPDA	PPTLOLPDT	0.05906	0.02446	0.00016	0.00001	0.00009	0.00001	0.00000	0.00018	0.00003

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Meter Cost Allocation											
Meters Gross Plant Residual Allocator		MGPRA		49,194,750	29,720,264	11,993,013	244,803	3,749,767	733,308	670,691	1,299,034
Meters Gross Plant Costs				$ 77,142,557							
Customer Specific Assignment				$ 159,234							
Meters Gross Plant Residual			MGPRA	$ 76,983,323	$ 46,508,310	$ 18,767,490	$ 383,084	$ 5,867,892	$ 1,147,531	$ 1,049,543	$ 2,032,818
Meters Gross Plant Total		MGPT		$ 77,142,557	$ 46,508,310	$ 18,767,490	$ 383,084	$ 5,867,892	$ 1,147,531	$ 1,049,543	$ 2,032,818
Meters Gross Plant Allocator		MGPA	MGPT	1.000000	0.60289	0.24328	0.00497	0.07607	0.01488	0.01361	0.02635
Meters Net Plant Residual Allocator		MNPRA		49,194,750	29,720,264	11,993,013	244,803	3,749,767	733,308	670,691	1,299,034
Meters Net Plant Costs				$ 53,653,152							
Customer Specific Assignment				$ 120,013							
Meters Net Plant Residual			MNPRA	$ 53,533,140	$ 32,341,236	$ 13,050,653	$ 266,391	$ 4,080,451	$ 797,977	$ 729,838	$ 1,413,594
Meters Net Plant Total		MNPT		$ 53,653,152	$ 32,341,236	$ 13,050,653	$ 266,391	$ 4,080,451	$ 797,977	$ 729,838	$ 1,413,594
Meters Net Plant Allocator		MNPA	MNPT	1.000000	0.60278	0.24324	0.00497	0.07605	0.01487	0.01360	0.02635
Meters Rate Base Residual Allocator		MRBRA		49,194,750	29,720,264	11,993,013	244,803	3,749,767	733,308	670,691	1,299,034
Meters Rate Base Costs				$ 45,031,431							
Customer Specific Assignment				$ 89,399							
Meters Rate Base Residual			MRBRA	$ 44,942,032	$ 27,151,049	$ 10,956,258	$ 223,640	$ 3,425,612	$ 669,916	$ 612,712	$ 1,186,737
Meters Rate Base Total		MRBT		$ 45,031,431	$ 27,151,049	$ 10,956,258	$ 223,640	$ 3,425,612	$ 669,916	$ 612,712	$ 1,186,737
Meters Rate Base Allocator		MRBA	MRBT	1.000000	0.60294	0.24330	0.00497	0.07607	0.01488	0.01361	0.02635
Meters O&M Residual Allocator		MOMRA		49,194,750	29,720,264	11,993,013	244,803	3,749,767	733,308	670,691	1,299,034
Meters O&M Costs				$ 11,537,188							
Customer Specific Assignment				$ -							
Meters O&M Residual			MOMRA	$ 11,537,188	$ 6,970,017	$ 2,812,610	$ 57,411	$ 879,398	$ 171,976	$ 157,291	$ 304,650
Meters O&M Total		MOMT		$ 11,537,188	$ 6,970,017	$ 2,812,610	$ 57,411	$ 879,398	$ 171,976	$ 157,291	$ 304,650
Meters O&M Allocator		MOMA	MOMT	1.000000	0.60413	0.24379	0.00498	0.07622	0.01491	0.01363	0.02641
Meters Depreciation Residual Allocator		MDRA		49,194,750	29,720,264	11,993,013	244,803	3,749,767	733,308	670,691	1,299,034
Meters Depreciation Costs				$ 1,599,033							
Customer Specific Assignment				$ 15,923							
Meters Depreciation Residual			MDRA	$ 1,583,110	$ 956,412	$ 385,941	$ 7,878	$ 120,669	$ 23,598	$ 21,583	$ 41,804
Meters Depreciation Total		MDT		$ 1,599,033	$ 956,412	$ 385,941	$ 7,878	$ 120,669	$ 23,598	$ 21,583	$ 41,804
Meters Depreciation Allocator		MDA	MDT	1.000000	0.59812	0.24136	0.00493	0.07546	0.01476	0.01350	0.02614
Meters Prop Tax Residual Allocator		MPTRA		49,194,750	29,720,264	11,993,013	244,803	3,749,767	733,308	670,691	1,299,034
Meters Prop Tax Costs				$ 286,653							
Customer Specific Assignment				$ 1,987							
Meters Prop Tax Residual			MPTRA	$ 284,666	$ 171,977	$ 69,398	$ 1,417	$ 21,698	$ 4,243	$ 3,881	$ 7,517
Meters Prop Tax Total		MPTT		$ 286,653	$ 171,977	$ 69,398	$ 1,417	$ 21,698	$ 4,243	$ 3,881	$ 7,517
Meters Prop Tax Allocator		MPTA	MPTT	1.000000	0.59995	0.24210	0.00494	0.07569	0.01480	0.01354	0.02622
Customer Service O&M Cost Allocation											
Customer Service Residual Allocator		CSRA		550,667	442,342	82,784	424	4,441	204	766	256
Customer Service O&M Costs				$ 7,173,760							
Customer Specific Assignment				$ 25,500							
Customer Service O&M Residual			CSRA	$ 7,148,260	$ 5,742,083	$ 1,074,627	$ 5,504	$ 57,649	$ 2,648	$ 9,944	$ 3,323
Customer Service O&M Total		CSOT		$ 7,173,760	$ 5,742,083	$ 1,074,627	$ 5,504	$ 57,649	$ 2,648	$ 9,944	$ 3,323
Customer Service O&M Allocator		C10	CSOT	1.000000	0.80043	0.14980	0.00077	0.00804	0.00037	0.00139	0.00046

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Meter Cost Allocation												
Meters Gross Plant Residual Allocator		MGPRA		644,052	39,757	-	7,256	89,428	3,378	-	-	-
Meters Gross Plant Costs												0
Customer Specific Assignment										$ 159,234	$ -	
Meters Gross Plant Residual			MGPRA	$ 1,007,857	$ 62,215	$ -	$ 11,355	$ 139,943	$ 5,286	$ -	$ -	$ -
Meters Gross Plant Total		MGPT		$ 1,007,857	$ 62,215	$ -	$ 11,355	$ 139,943	$ 5,286	$ 159,234	$ -	$ -
Meters Gross Plant Allocator		MGPA	MGPT	0.01306	0.00081	-	0.00015	0.00181	0.00007	0.00206	-	-
Meters Net Plant Residual Allocator		MNPRA		644,052	39,757	-	7,256	89,428	3,378	-	-	-
Meters Net Plant Costs												-
Customer Specific Assignment										$ 120,013	$ -	
Meters Net Plant Residual			MNPRA	$ 700,850	$ 43,263	$ -	$ 7,896	$ 97,314	$ 3,676	$ -	$ -	$ -
Meters Net Plant Total		MNPT		$ 700,850	$ 43,263	$ -	$ 7,896	$ 97,314	$ 3,676	$ 120,013	$ -	$ -
Meters Net Plant Allocator		MNPA	MNPT	0.01306	0.00081	-	0.00015	0.00181	0.00007	0.00224	-	-
Meters Rate Base Residual Allocator		MRBRA		644,052	39,757	-	7,256	89,428	3,378	-	-	-
Meters Rate Base Costs												-
Customer Specific Assignment										$ 89,399	$ -	
Meters Rate Base Residual			MRBRA	$ 588,376	$ 36,320	$ -	$ 6,629	$ 81,697	$ 3,086	$ -	$ -	$ -
Meters Rate Base Total		MRBT		$ 588,376	$ 36,320	$ -	$ 6,629	$ 81,697	$ 3,086	$ 89,399	$ -	$ -
Meters Rate Base Allocator		MRBA	MRBT	0.01307	0.00081	-	0.00015	0.00181	0.00007	0.00199	-	-
Meters O&M Residual Allocator		MOMRA		644,052	39,757	-	7,256	89,428	3,378	-	-	-
Meters O&M Costs												-
Customer Specific Assignment										$ -	$ -	
Meters O&M Residual			MOMRA	$ 151,044	$ 9,324	$ -	$ 1,702	$ 20,973	$ 792	$ -	$ -	$ -
Meters O&M Total		MOMT		$ 151,044	$ 9,324	$ -	$ 1,702	$ 20,973	$ 792	$ -	$ -	$ -
Meters O&M Allocator		MOMA	MOMT	0.01309	0.00081	-	0.00015	0.00182	0.00007	-	-	-
Meters Depreciation Residual Allocator		MDRA		644,052	39,757	-	7,256	89,428	3,378	-	-	-
Meters Depreciation Costs												-
Customer Specific Assignment										$ 15,923	$ -	
Meters Depreciation Residual			MDRA	$ 20,726	$ 1,279	$ -	$ 234	$ 2,878	$ 109	$ -	$ -	$ -
Meters Depreciation Total		MDT		$ 20,726	$ 1,279	$ -	$ 234	$ 2,878	$ 109	$ 15,923	$ -	$ -
Meters Depreciation Allocator		MDA	MDT	0.01296	0.00080	-	0.00015	0.00180	0.00007	0.00996	-	-
Meters Prop Tax Residual Allocator		MPTRA		644,052	39,757	-	7,256	89,428	3,378	-	-	-
Meters Prop Tax Costs												-
Customer Specific Assignment										$ 1,987	$ -	
Meters Prop Tax Residual			MPTRA	$ 3,727	$ 230	$ -	$ 42	$ 517	$ 20	$ -	$ -	$ -
Meters Prop Tax Total		MPTT		$ 3,727	$ 230	$ -	$ 42	$ 517	$ 20	$ 1,987	$ -	$ -
Meters Prop Tax Allocator		MPTA	MPTT	0.01300	0.00080	-	0.00015	0.00181	0.00007	0.00693	-	-
Customer Service O&M Cost Allocation												
Customer Service Residual Allocator		CSRA		20	1	19,255	12	148	4	10	-	-
Customer Service O&M Costs												-
Customer Specific Assignment										$ 18,500	$ -	$ 7,000
Customer Service O&M Residual			CSRA	$ 260	$ 13	$ 249,951	$ 156	$ 1,921	$ 52	$ 130	$ -	$ -
Customer Service O&M Total		CSOT		$ 260	$ 13	$ 249,951	$ 156	$ 1,921	$ 52	$ 18,630	$ -	$ 7,000
Customer Service O&M Allocator		C10	CSOT	0.00004	0.00000	0.03484	0.00002	0.00027	0.00001	0.00260	-	0.00098

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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
Revenue Adjustment Allocators											
Late Payment Revenue		LPAY		3,985,852	3,094,551	620,986	18,514	193,986	8,902	33,474	11,163
Misc Service Revenue Allocator		MISCSERV		1,671,784	174,180	326,081	80,661	845,167	38,783	145,842	48,635
Reconnect Charges		RECON		1,827,840	1,740,900	83,412	233	2,442	112	421	140
Return Check Charges		RETURN		86,978	81,062	5,025	60	629	29	109	36
Rent From Electric Property		RFEP		5,194,858,581	2,457,262,896	610,215,074	38,745,077	458,917,674	19,889,476	424,876,670	740,522,922
Interruptible Credit Allocator		INTCRE		6,069,280,510	2,490,784,384	670,878,802	43,048,460	625,621,337	27,180,233	601,676,613	1,101,435,630
Base Rate Revenue				1,558,570,103	611,492,797	224,799,513	11,901,436	169,760,857	9,429,915	134,172,118	250,417,886
Operation and Maintenance Less Fuel		OMLF		336,831,286	177,368,926	48,629,289	2,429,334	25,390,922	1,221,079	22,575,247	36,974,577
CSR Avoided Cost											
Interruptible Demand				3,184,853							201,529
Avoided Cost per kW											$ (5.12)
Avoided Cost				$ (18,634,070)							$ (1,032,456)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2022

LOLP Methodology

Description	Ref	Name	Allocation Vector	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	Business Solar BS
Revenue Adjustment Allocators												
Late Payment Revenue		LPAY		874	44	3,359	-	-	-	-		-
Misc Service Revenue Allocator		MISCSERV		3,806	190	8,439	-	-	-	-		-
Reconnect Charges		RECON		11	1	168						-
Return Check Charges		RETURN		3	0	25						-
Rent From Electric Property		RFEP		225,552,349	104,343,933	113,343,713	398,777	615,338	174,679			-
Interruptible Credit Allocator		INTCRE		358,533,878	148,468,386	967,726	35,209	575,745	74,108	-	-	-
Base Rate Revenue				82,247,981	32,956,814	30,555,893	307,246	271,291	92,320	1,533	162,504	-
Operation and Maintenance Less Fuel		OMLF		10,977,306	5,227,214	5,822,389	26,421	63,498	12,458	21,111	91,514	-
CSR Avoided Cost												
Interruptible Demand				573,919	2,409,406							-
Avoided Cost per kW				$ (5.90)	$ (5.90)							
Avoided Cost				$ (3,386,120)	$ (14,215,494)							-

Exhibit WSS-32

Electric Cost of Service Study
Class Allocation
(Louisville Gas and Electric Company)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Plant in Service												
Power Production Plant												
Production Demand - LOLP	TUP	PLPPLOLP	GPLOLPDA	$ 3,865,573,604	$ 1,843,044,295	$ 434,979,325	$ 29,452,187	$ 487,053,951	$ 462,893,194	$ 380,591,965	$ 211,887,495	$ 11,650,517
Production Energy	TUP	PLPPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 3,865,573,604	$ 1,843,044,295	$ 434,979,325	$ 29,452,187	$ 487,053,951	$ 462,893,194	$ 380,591,965	$ 211,887,495	$ 11,650,517
Transmission Plant												
Transmission Demand	TUP	PLTRB	NCPT	$ 612,587,887	$ 289,827,323	$ 70,795,598	$ 4,647,245	$ 78,773,671	$ 66,061,501	$ 62,543,037	$ 32,615,094	$ 2,095,869
Distribution Poles												
Specific	TUP	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TUP	PLDSG	NCPP	$ 234,986,652	$ 117,428,875	$ 28,684,140	$ 1,882,917	$ 31,916,603	$ 26,766,033	$ 25,340,463	$ -	$ 849,180
Distribution Primary & Secondary Lines												
Primary Specific	TUP	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TUP	PLDPLD	NCPP	360,746,498	180,274,304	44,035,280	2,890,614	48,997,688	41,090,643	38,902,138	-	1,303,643
Primary Customer	TUP	PLDPLC	PCust08	590,335,970	511,648,810	61,431,953	94,861	3,771,400	178,881	684,354	17,617	2,710
Secondary Demand	TUP	PLDSLD	SICD	100,651,565	76,294,060	12,193,195	-	11,548,657	-	-	-	-
Secondary Customer	TUP	PLDSLC	PCust07	171,988,888	150,203,342	18,034,410	27,848	-	52,514	-	-	-
Total Distribution Primary & Secondary Lines		PLDLT		$ 1,223,722,920	$ 918,420,516	$ 135,694,838	$ 3,013,323	$ 64,317,745	$ 41,322,037	$ 39,586,492	$ 17,617	$ 1,306,353
Distribution Line Transformers												
Demand	TUP	PLDLTD	SICDT	$ 123,303,836	$ 85,300,381	$ 13,632,571	$ -	$ 12,911,946	$ -	$ 10,770,607	$ -	$ -
Customer	TUP	PLDLTC	PCust09	68,730,533	59,598,980	7,155,849	-	439,308	-	79,716	-	-
Total Distribution Line Transformers		PLDLTT		$ 192,034,369	$ 144,899,361	$ 20,788,420	$ -	$ 13,351,255	$ -	$ 10,850,323	$ -	$ -
Distribution Services												
Customer	TUP	PLDSC	C02	$ 43,944,308	$ 37,850,187	$ 5,390,780	$ -	$ 554,489	$ -	$ 148,652	$ -	$ -
Distribution Meters												
Customer	TUP	PLDMC	MGPA	$ 44,815,612	$ 30,508,190	$ 9,479,010	$ 309,833	$ 2,650,782	$ 618,860	$ 524,043	$ 437,345	$ 9,406
Distribution Street & Customer Lighting												
Customer	TUP	PLDSCL	PCust04	$ 144,886,355	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TUP	PLCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TUP	PLCSI	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TUP	PLSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 6,362,551,708	$ 3,381,978,746	$ 705,812,112	$ 39,305,506	$ 678,618,495	$ 597,661,624	$ 519,584,976	$ 244,957,551	$ 15,911,324

LOUISVILLE GAS AND ELECTRIC COMPANY
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Class Allocation

12 Months Ended
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Description	Ref	Name	Allocation Vector	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
		1	2	12	13	14	15	16	17	18
Plant in Service										
Power Production Plant										
Production Demand - LOLP	TUP	PLPPLOLP	GPLOLPDA	$ 646,656	$ 22,523	$ 627,517	$ 1,493	$ 6,773	$ 2,630,743	$ 84,972
Production Energy	TUP	PLPPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 646,656	$ 22,523	$ 627,517	$ 1,493	$ 6,773	$ 2,630,743	$ 84,972
Transmission Plant										
Transmission Demand	TUP	PLTRB	NCPT	$ 4,966,644	$ 172,988	$ 79,410	$ 8,642	$ 865	$ -	$ -
Distribution Poles										
Specific	TUP	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TUP	PLDSG	NCPP	$ 2,012,327	$ 70,089	$ 32,174	$ 3,501	$ 351	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TUP	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TUP	PLDPLD	NCPP	3,089,282	107,600	49,393	5,375	538	-	-
Primary Customer	TUP	PLDPLC	PCust08	12,333,143	21,818	135,516	1,355	13,552	-	-
Secondary Demand	TUP	PLDSLD	SICD	584,814	20,369	9,350	1,018	102	-	-
Secondary Customer	TUP	PLDSLC	PCust07	3,620,607	6,405	39,783	-	3,978	-	-
Total Distribution Primary & Secondary Lines		PLDLT		$ 19,627,847	$ 156,192	$ 234,042	$ 7,748	$ 18,170	$ -	$ -
Distribution Line Transformers										
Demand	TUP	PLDLTD	SICDT	$ 653,850	$ 22,774	$ 10,454	$ 1,138	$ 114	$ -	$ -
Customer	TUP	PLDLTC	PCust09	1,436,616	2,541	15,785	158	1,579	-	-
Total Distribution Line Transformers		PLDLTT		$ 2,090,466	$ 25,315	$ 26,240	$ 1,296	$ 1,692	$ -	$ -
Distribution Services										
Customer	TUP	PLDSC	C02	$ -	$ -	$ -	$ 199	$ -	$ -	$ -
Distribution Meters										
Customer	TUP	PLDMC	MGPA	$ -	$ 13,008	$ 80,795	$ 953	$ 183,388	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TUP	PLDSCL	PCust04	$ 144,886,355	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TUP	PLCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TUP	PLCSI	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TUP	PLSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 174,230,296	$ 460,116	$ 1,080,178	$ 23,832	$ 211,239	$ 2,630,743	$ 84,972

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Net Utility Plant												
Power Production Plant												
Production Demand - LOLP	NTPLANT	UPPPLOLP	NPLOLPDA	$ 2,495,383,413	$ 1,189,374,765	$ 280,705,913	$ 19,006,428	$ 314,311,316	$ 298,719,616	$ 245,608,030	$ 136,737,701	$ 7,518,447
Production Energy	NTPLANT	UPPPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 2,495,383,413	$ 1,189,374,765	$ 280,705,913	$ 19,006,428	$ 314,311,316	$ 298,719,616	$ 245,608,030	$ 136,737,701	$ 7,518,447
Transmission Plant												
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 422,249,551	$ 199,774,530	$ 48,798,564	$ 3,203,291	$ 54,297,755	$ 45,535,407	$ 43,110,172	$ 22,481,197	$ 1,444,657
Distribution Poles												
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	NTPLANT	UPDSG	NCPP	$ 158,088,627	$ 79,000,953	$ 19,297,421	$ 1,266,743	$ 21,472,079	$ 18,007,003	$ 17,047,943	$ -	$ 571,291
Distribution Primary & Secondary Lines												
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	242,694,290	121,280,579	29,624,989	1,944,677	32,963,477	27,643,967	26,171,638	-	877,033
Primary Customer	NTPLANT	UPDPLC	PCust08	397,151,933	344,214,691	41,328,701	63,818	2,537,231	120,343	460,403	11,852	1,823
Secondary Demand	NTPLANT	UPDSLD	SICD	67,713,921	51,327,269	8,203,043	-	7,769,425	-	-	-	-
Secondary Customer	NTPLANT	UPDSLC	PCust07	115,706,517	101,050,166	12,132,754	18,735	-	35,329	-	-	-
Total Distribution Primary & Secondary Lines		UPDLT		$ 823,266,661	$ 617,872,706	$ 91,289,486	$ 2,027,230	$ 43,270,134	$ 27,799,639	$ 26,632,041	$ 11,852	$ 878,857
Distribution Line Transformers												
Demand	NTPLANT	UPDLTD	SICDT	$ 82,953,368	$ 57,386,324	$ 9,171,391	$ -	$ 8,686,587	$ -	$ 7,245,988	$ -	$ -
Customer	NTPLANT	UPDLTC	PCust09	46,238,863	40,095,558	4,814,139	-	295,547	-	53,630	-	-
Total Distribution Line Transformers		UPDLTT		$ 129,192,231	$ 97,481,882	$ 13,985,530	$ -	$ 8,982,134	$ -	$ 7,299,618	$ -	$ -
Distribution Services												
Customer	NTPLANT	UPDSC	C02	$ 29,563,787	$ 25,463,932	$ 3,626,678	$ -	$ 373,036	$ -	$ 100,007	$ -	$ -
Distribution Meters												
Customer	NTPLANT	UPDMC	MNPA	$ 30,149,962	$ 20,513,748	$ 6,373,699	$ 208,332	$ 1,782,389	$ 416,122	$ 352,367	$ 294,071	$ 6,324
Distribution Street & Customer Lighting												
Customer	NTPLANT	UPDSCL	PCust04	$ 97,473,132	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	NTPLANT	UPCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	NTPLANT	UPCSI	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	NTPLANT	UPSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 4,185,367,364	$ 2,229,482,516	$ 464,077,292	$ 25,712,025	$ 444,488,843	$ 390,477,788	$ 340,150,178	$ 159,524,821	$ 10,419,576

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Net Utility Plant										
Power Production Plant										
Production Demand - LOLP	NTPLANT	UPPPLOLP	NPLOLPDA	$ 417,308	$ 14,535	$ 404,956	$ 963	$ 4,371	$ 2,486,734	$ 72,329
Production Energy	NTPLANT	UPPPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 417,308	$ 14,535	$ 404,956	$ 963	$ 4,371	$ 2,486,734	$ 72,329
Transmission Plant										
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 3,423,449	$ 119,239	$ 54,736	$ 5,957	$ 596	$ -	$ -
Distribution Poles										
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	NTPLANT	UPDSG	NCPP	$ 1,353,805	$ 47,153	$ 21,645	$ 2,356	$ 236	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	2,078,332	72,388	33,230	3,616	362	-	-
Primary Customer	NTPLANT	UPDPLC	PCust08	8,297,193	14,678	91,169	912	9,117	-	-
Secondary Demand	NTPLANT	UPDSLD	SICD	393,437	13,703	6,291	685	69	-	-
Secondary Customer	NTPLANT	UPDSLC	PCust07	2,435,784	4,309	26,764	-	2,676	-	-
Total Distribution Primary & Secondary Lines		UPDLT		$ 13,204,747	$ 105,079	$ 157,453	$ 5,213	$ 12,224	$ -	$ -
Distribution Line Transformers										
Demand	NTPLANT	UPDLTD	SICDT	$ 439,882	$ 15,321	$ 7,033	$ 765	$ 77	$ -	$ -
Customer	NTPLANT	UPDLTC	PCust09	966,492	1,710	10,620	106	1,062	-	-
Total Distribution Line Transformers		UPDLTT		$ 1,406,373	$ 17,031	$ 17,653	$ 872	$ 1,139	$ -	$ -
Distribution Services										
Customer	NTPLANT	UPDSC	C02	$ -	$ -	$ -	$ 134	$ -	$ -	$ -
Distribution Meters										
Customer	NTPLANT	UPDMC	MNPA	$ -	$ 8,747	$ 54,327	$ 641	$ 139,194	$ -	$ -
Distribution Street & Customer Lighting										
Customer	NTPLANT	UPDSCL	PCust04	$ 97,473,132	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	NTPLANT	UPCAE	PCust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	NTPLANT	UPCSI	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	NTPLANT	UPSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 117,278,814	$ 311,783	$ 710,771	$ 16,135	$ 157,760	$ 2,486,734	$ 72,329

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

		1	2	3	4	5	6	7	8	9	10	11
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service Rate GS**	**Rate PS Primary**	**Rate PS Secondary**	**Rate TOD Primary**	**Rate TOD Secondary**	**Rate RTS Transmission**	**Special Contract Customer**
Net Cost Rate Base												
Power Production Plant												
Production Demand - LOLP	RB	RBPPLOLP	RBLOLPDA	$ 2,009,588,145	$ 957,680,114	$ 226,023,352	$ 15,303,905	$ 253,082,297	$ 240,527,918	$ 197,762,668	$ 110,100,685	$ 6,053,825
Production Energy	RB	RBPPEB	E01	78,365,699	28,168,165	8,327,707	705,537	10,496,681	13,568,786	8,961,061	7,018,768	383,711
Total Power Production Plant		RBPPT		$ 2,087,953,844	$ 985,848,280	$ 234,351,059	$ 16,009,441	$ 263,578,977	$ 254,096,704	$ 206,723,729	$ 117,119,453	$ 6,437,537
Transmission Plant												
Transmission Demand	RB	RBTRB	NCPT	$ 346,878,037	$ 164,114,791	$ 40,088,024	$ 2,631,504	$ 44,605,610	$ 37,407,341	$ 35,415,010	$ 18,468,305	$ 1,186,786
Distribution Poles												
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	RB	RBDSG	NCPP	$ 127,246,319	$ 63,588,259	$ 15,532,589	$ 1,019,608	$ 17,282,982	$ 14,493,926	$ 13,721,973	$ -	$ 459,835
Distribution Primary & Secondary Lines												
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	194,814,177	97,353,655	23,780,402	1,561,020	26,460,255	22,190,208	21,008,348	-	704,007
Primary Customer	RB	RBDPLC	PCust08	318,901,474	276,394,405	33,185,747	51,244	2,037,323	96,632	369,690	9,517	1,464
Secondary Demand	RB	RBDSLD	SICD	54,455,747	41,277,550	6,596,912	-	6,248,196	-	-	-	-
Secondary Customer	RB	RBDSLC	PCust07	93,072,232	81,282,928	9,759,368	15,070	-	28,418	-	-	-
Total Distribution Primary & Secondary Lines		RBDLT		$ 661,243,630	$ 496,308,539	$ 73,322,430	$ 1,627,334	$ 34,745,774	$ 22,315,258	$ 21,378,038	$ 9,517	$ 705,471
Distribution Line Transformers												
Demand	RB	RBDLTD	SICDT	$ 66,122,625	$ 45,742,982	$ 7,310,571	$ -	$ 6,924,130	$ -	$ 5,775,820	$ -	$ -
Customer	RB	RBDLTC	PCust09	36,857,274	31,960,409	3,837,379	-	235,582	-	42,749	-	-
Total Distribution Line Transformers		RBDLTT		$ 102,979,899	$ 77,703,391	$ 11,147,950	$ -	$ 7,159,713	$ -	$ 5,818,569	$ -	$ -
Distribution Services												
Customer	RB	RBDSC	C02	$ 23,551,954	$ 20,285,809	$ 2,889,189	$ -	$ 297,179	$ -	$ 79,670	$ -	$ -
Distribution Meters												
Customer	RB	RBDMC	MRBA	$ 26,834,745	$ 18,270,840	$ 5,676,819	$ 185,554	$ 1,587,509	$ 370,625	$ 313,841	$ 261,918	$ 5,633
Distribution Street & Customer Lighting												
Customer	RB	RBDSCL	PCust04	$ 77,771,357	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	RB	RBCAE	PCust05	$ 4,604,270	$ 3,422,078	$ 821,755	$ 3,172	$ 126,122	$ 29,910	$ 114,430	$ 2,946	$ 91
Customer Service & Info.												
Customer	RB	RBCSI	PCust06	$ 1,013,761	$ 878,634	$ 105,495	$ 163	$ 6,476	$ 307	$ 1,175	$ 30	$ 5
Sales Expense												
Customer	RB	RBSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 3,460,077,816	$ 1,830,420,621	$ 383,935,310	$ 21,476,777	$ 369,390,342	$ 328,714,071	$ 283,566,435	$ 135,862,169	$ 8,795,357

12 Months Ended
June 30, 2022

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Net Cost Rate Base										
Power Production Plant										
Production Demand - LOLP	RB	RBPPLOLP	RBLOLPDA	$ 336,015	$ 11,703	$ 326,069	$ 776	$ 3,520	$ 2,314,622	$ 60,677
Production Energy	RB	RBPPEB	E01	688,717	23,988	22,371	80	127	-	-
Total Power Production Plant		RBPPT		$ 1,024,731	$ 35,691	$ 348,440	$ 856	$ 3,646	$ 2,314,622	$ 60,677
Transmission Plant										
Transmission Demand	RB	RBTRB	NCPT	$ 2,812,363	$ 97,955	$ 44,966	$ 4,893	$ 490	$ -	$ -
Distribution Poles										
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	RB	RBDSG	NCPP	$ 1,089,684	$ 37,954	$ 17,423	$ 1,896	$ 190	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	1,668,307	58,107	26,674	2,903	291	-	-
Primary Customer	RB	RBDPLC	PCust08	6,662,406	11,786	73,206	732	7,321	-	-
Secondary Demand	RB	RBDSLD	SICD	316,403	11,020	5,059	551	55	-	-
Secondary Customer	RB	RBDSLC	PCust07	1,959,301	3,466	21,529	-	2,153	-	-
Total Distribution Primary & Secondary Lines		RBDLT		$ 10,606,417	$ 84,380	$ 126,467	$ 4,185	$ 9,819	$ -	$ -
Distribution Line Transformers										
Demand	RB	RBDLTD	SICDT	$ 350,632	$ 12,213	$ 5,606	$ 610	$ 61	$ -	$ -
Customer	RB	RBDLTC	PCust09	770,396	1,363	8,465	85	847	-	-
Total Distribution Line Transformers		RBDLTT		$ 1,121,028	$ 13,575	$ 14,071	$ 695	$ 908	$ -	$ -
Distribution Services										
Customer	RB	RBDSC	C02	$ -	$ -	$ -	$ 107	$ -	$ -	$ -
Distribution Meters										
Customer	RB	RBDMC	MRBA	$ -	$ 7,790	$ 48,387	$ 571	$ 105,259	$ -	$ -
Distribution Street & Customer Lighting										
Customer	RB	RBDSCL	PCust04	$ 77,771,357	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	RB	RBCAE	PCust05	$ 82,488	$ 146	$ 906	$ 45	$ 181	$ -	$ -
Customer Service & Info.										
Customer	RB	RBCSI	PCust06	$ 21,179	$ 37	$ 233	$ 2	$ 23	$ -	$ -
Sales Expense										
Customer	RB	RBSEC	PCust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 94,529,248	$ 277,529	$ 600,893	$ 13,251	$ 120,516	$ 2,314,622	$ 60,677

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Operation and Maintenance Expenses												
Power Production Plant												
Production Demand - LOLP	TOM	OMPPLOLP	POMLOLPDA	$ 111,958,098	$ 53,383,070	$ 12,599,009	$ 853,071	$ 14,107,331	$ 13,407,524	$ 11,023,700	$ 6,137,240	$ 337,453
Production Energy	TOM	OMPPEB	E01	397,495,519	142,877,811	42,240,755	3,578,705	53,242,471	68,825,160	45,453,324	35,601,403	1,946,305
Total Power Production Plant		OMPPT		$ 509,453,617	$ 196,260,881	$ 54,839,764	$ 4,431,776	$ 67,349,802	$ 82,232,684	$ 56,477,024	$ 41,738,643	$ 2,283,758
Transmission Plant												
Transmission Demand	TOM	OMTRB	NCPT	$ 34,465,993	$ 16,306,536	$ 3,983,168	$ 261,468	$ 4,432,038	$ 3,716,814	$ 3,518,855	$ 1,835,021	$ 117,920
Distribution Poles												
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TOM	OMDSG	NCPP	$ 8,074,379	$ 4,034,975	$ 985,616	$ 64,699	$ 1,096,687	$ 919,708	$ 870,724	$ -	$ 29,179
Distribution Primary & Secondary Lines												
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	13,200,175	6,596,467	1,611,307	105,771	1,792,888	1,503,559	1,423,479	-	47,702
Primary Customer	TOM	OMDPLC	Cust08	22,092,724	19,102,731	2,294,729	3,541	140,762	6,657	25,548	-	101
Secondary Demand	TOM	OMDSLD	SICD	4,169,129	3,160,207	505,059	-	478,362	-	-	-	-
Secondary Customer	TOM	OMDSLC	Cust07	7,223,791	6,296,483	756,370	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OMDLT		$ 46,685,818	$ 35,155,888	$ 5,167,465	$ 109,313	$ 2,412,011	$ 1,510,216	$ 1,449,027	$ -	$ 47,803
Distribution Line Transformers												
Demand	TOM	OMDLTD	SICDT	$ 1,117,029	$ 772,750	$ 123,500	$ -	$ 116,971	$ -	$ 97,573	$ -	$ -
Customer	TOM	OMDLTC	Cust09	622,641	538,625	64,703	-	3,969	-	720	-	-
Total Distribution Line Transformers		OMDLTT		$ 1,739,670	$ 1,311,375	$ 188,202	$ -	$ 120,940	$ -	$ 98,293	$ -	$ -
Distribution Services												
Customer	TOM	OMDSC	C02	$ 332,913	$ 286,745	$ 40,839	$ -	$ 4,201	$ -	$ 1,126	$ -	$ -
Distribution Meters												
Customer	TOM	OMDMC	MOMA	$ 13,918,315	$ 9,513,812	$ 2,955,978	$ 96,620	$ 826,632	$ 192,988	$ 163,420	$ 136,384	$ 2,933
Distribution Street & Customer Lighting												
Customer	TOM	OMDSCL	C04	$ 1,673,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TOM	OMCAE	C05	$ 22,203,328	$ 16,468,323	$ 3,956,538	$ 15,265	$ 606,747	$ 143,482	$ 550,624	$ 14,174	$ 436
Customer Service & Info.												
Customer	TOM	OMCSI	C10	$ 4,888,693	$ 4,197,542	$ 504,233	$ 778	$ 30,930	$ 1,463	$ 5,614	$ 145	$ 22
Sales Expense												
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 643,436,661	$ 283,536,077	$ 72,621,803	$ 4,979,918	$ 76,879,988	$ 88,717,355	$ 63,134,706	$ 43,724,366	$ 2,482,051

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		1	2	12	13	14	15	16	17	18
Description	**Ref**	**Name**	**Allocation Vector**	**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**
Operation and Maintenance Expenses										
Power Production Plant										
Production Demand - LOLP	TOM	OMPPLOLP	POMLOLPDA	$ 18,730	$ 652	$ 18,176	$ 43	$ 196	$ 71,903	$ -
Production Energy	TOM	OMPPEB	E01	3,493,388	121,675	113,470	408	644	-	-
Total Power Production Plant		OMPPT		$ 3,512,118	$ 122,327	$ 131,646	$ 451	$ 840	$ 71,903	$ -
Transmission Plant										
Transmission Demand	TOM	OMTRB	NCPT	$ 279,438	$ 9,733	$ 4,468	$ 486	$ 49	$ -	$ -
Distribution Poles										
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TOM	OMDSG	NCPP	$ 69,146	$ 2,408	$ 1,106	$ 120	$ 12	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	113,041	3,937	1,807	197	20	-	-
Primary Customer	TOM	OMDPLC	Cust08	511,572	905	5,621	51	506	-	-
Secondary Demand	TOM	OMDSLD	SICD	24,224	844	387	42	4	-	-
Secondary Customer	TOM	OMDSLC	Cust07	168,620	298	1,853	-	167	-	-
Total Distribution Primary & Secondary Lines		OMDLT		$ 817,457	$ 5,984	$ 9,669	$ 289	$ 697	$ -	$ -
Distribution Line Transformers										
Demand	TOM	OMDLTD	SICDT	$ 5,923	$ 206	$ 95	$ 10	$ 1	$ -	$ -
Customer	TOM	OMDLTC	Cust09	14,424	26	158	1	14	-	-
Total Distribution Line Transformers		OMDLTT		$ 20,348	$ 232	$ 253	$ 12	$ 15	$ -	$ -
Distribution Services										
Customer	TOM	OMDSC	C02	$ -	$ -	$ -	$ 2	$ -	$ -	$ -
Distribution Meters										
Customer	TOM	OMDMC	MOMA	$ -	$ 4,056	$ 25,196	$ 297	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TOM	OMDSCL	C04	$ 1,673,935	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TOM	OMCAE	C05	$ 441,022	$ 780	$ 4,846	$ 218	$ 872	$ -	$ -
Customer Service & Info.										
Customer	TOM	OMCSI	C10	$ 112,410	$ 199	$ 1,235	$ 11	$ 24,111	$ -	$ 10,000
Sales Expense										
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 6,925,874	$ 145,720	$ 178,418	$ 1,886	$ 26,596	$ 71,903	$ 10,000

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		1	2	3	4	5	6	7	8	9	10	11
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service Rate GS**	**Rate PS Primary**	**Rate PS Secondary**	**Rate TOD Primary**	**Rate TOD Secondary**	**Rate RTS Transmission**	**Special Contract Customer**
Labor Expenses												
Power Production Plant												
Production Demand - LOLP	TLB	LBPPLOLP	LOLP	$ 24,034,852	$ 11,467,493	$ 2,706,458	$ 183,253	$ 3,030,469	$ 2,880,139	$ 2,368,058	$ 1,318,372	$ 72,490
Production Energy	TLB	LBPPEB	E01	20,124,090	7,233,505	2,138,532	181,180	2,695,518	3,484,426	2,301,175	1,802,400	98,536
Total Power Production Plant		LBPPT		$ 44,158,942	$ 18,700,998	$ 4,844,990	$ 364,433	$ 5,725,986	$ 6,364,565	$ 4,669,233	$ 3,120,772	$ 171,026
Transmission Plant												
Transmission Demand	TLB	LBTRB	NCPT	$ 5,515,515	$ 2,609,498	$ 637,417	$ 41,842	$ 709,249	$ 594,793	$ 563,114	$ 293,654	$ 18,870
Distribution Poles												
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TLB	LBDSG	NCPP	$ 2,294,469	$ 1,146,605	$ 280,079	$ 18,385	$ 311,642	$ 261,350	$ 247,431	$ -	$ 8,292
Distribution Primary & Secondary Lines												
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	2,285,841	1,142,293	279,026	18,316	310,470	260,368	246,500	-	8,260
Primary Customer	TLB	LBDPLC	Cust08	3,861,146	3,338,585	401,050	619	24,601	1,164	4,465	-	18
Secondary Demand	TLB	LBDSLD	SICD	756,973	573,787	91,702	-	86,854	-	-	-	-
Secondary Customer	TLB	LBDSLC	Cust07	1,317,944	1,148,762	137,996	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		LBDLT		$ 8,221,904	$ 6,203,427	$ 909,773	$ 18,935	$ 421,925	$ 261,531	$ 250,965	$ -	$ 8,278
Distribution Line Transformers												
Demand	TLB	LBDLTD	SICDT	$ 214,386	$ 148,310	$ 23,703	$ -	$ 22,450	$ -	$ 18,727	$ -	$ -
Customer	TLB	LBDLTC	Cust09	119,501	103,376	12,418	-	762	-	138	-	-
Total Distribution Line Transformers		LBDLTT		$ 333,887	$ 251,686	$ 36,121	$ -	$ 23,212	$ -	$ 18,865	$ -	$ -
Distribution Services												
Customer	TLB	LBDSC	C02	$ 54,624	$ 47,049	$ 6,701	$ -	$ 689	$ -	$ 185	$ -	$ -
Distribution Meters												
Customer	TLB	LBDMC	C03	$ 4,648,098	$ 3,177,190	$ 987,165	$ 32,267	$ 276,058	$ 64,449	$ 54,575	$ 45,546	$ 980
Distribution Street & Customer Lighting												
Customer	TLB	LBDSCL	C04	$ 187,932	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TLB	LBCAE	C05	$ 6,530,471	$ 4,843,684	$ 1,163,702	$ 4,490	$ 178,457	$ 42,201	$ 161,950	$ 4,169	$ 128
Customer Service & Info.												
Customer	TLB	LBCSI	C05	$ 1,422,705	$ 1,055,228	$ 253,520	$ 978	$ 38,878	$ 9,194	$ 35,282	$ 908	$ 28
Sales Expense												
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 73,368,547	$ 38,035,366	$ 9,119,468	$ 481,329	$ 7,686,097	$ 7,598,084	$ 6,001,600	$ 3,465,050	$ 207,602

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Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Labor Expenses										
Power Production Plant										
Production Demand - LOLP	TLB	LBPPLOLP	LOLP	$ 4,024	$ 140	$ 3,904	$ 9	$ 42	$ -	$ -
Production Energy	TLB	LBPPEB	E01	176,860	6,160	5,745	21	33	-	-
Total Power Production Plant		LBPPT		$ 180,884	$ 6,300	$ 9,649	$ 30	$ 75	$ -	$ -
Transmission Plant										
Transmission Demand	TLB	LBTRB	NCPT	$ 44,718	$ 1,558	$ 715	$ 78	$ 8	$ -	$ -
Distribution Poles										
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TLB	LBDSG	NCPP	$ 19,649	$ 684	$ 314	$ 34	$ 3	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	19,575	682	313	34	3	-	-
Primary Customer	TLB	LBDPLC	Cust08	89,407	158	982	9	88	-	-
Secondary Demand	TLB	LBDSLD	SICD	4,398	153	70	8	1	-	-
Secondary Customer	TLB	LBDSLC	Cust07	30,764	54	338	-	30	-	-
Total Distribution Primary & Secondary Lines		LBDLT		$ 144,145	$ 1,048	$ 1,704	$ 51	$ 123	$ -	$ -
Distribution Line Transformers										
Demand	TLB	LBDLTD	SICDT	$ 1,137	$ 40	$ 18	$ 2	$ 0	$ -	$ -
Customer	TLB	LBDLTC	Cust09	2,768	5	30	0	3	-	-
Total Distribution Line Transformers		LBDLTT		$ 3,905	$ 44	$ 49	$ 2	$ 3	$ -	$ -
Distribution Services										
Customer	TLB	LBDSC	C02	$ -	$ -	$ -	$ 0	$ -	$ -	$ -
Distribution Meters										
Customer	TLB	LBDMC	C03	$ -	$ 1,355	$ 8,414	$ 99	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TLB	LBDSCL	C04	$ 187,932	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TLB	LBCAE	C05	$ 129,714	$ 229	$ 1,425	$ 64	$ 257	$ -	$ -
Customer Service & Info.										
Customer	TLB	LBCSI	C05	$ 28,259	$ 50	$ 311	$ 14	$ 56	$ -	$ -
Sales Expense										
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 739,206	$ 11,268	$ 22,581	$ 372	$ 524	$ -	$ -

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Depreciation Expenses												
Power Production Plant												
Production Demand - LOLP	TDEPR	DEPPLOLP	PDEPLOLPDA	$ 212,733,072	$ 101,457,547	$ 23,945,130	$ 1,621,310	$ 26,811,781	$ 25,481,758	$ 20,951,166	$ 11,664,172	$ 641,348
Production Energy	TDEPR	DEPPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		DEPPT		$ 212,733,072	$ 101,457,547	$ 23,945,130	$ 1,621,310	$ 26,811,781	$ 25,481,758	$ 20,951,166	$ 11,664,172	$ 641,348
Transmission Plant												
Transmission Demand	TDEPR	DETRB	NCPT	$ 14,573,795	$ 6,895,148	$ 1,684,265	$ 110,560	$ 1,874,068	$ 1,571,639	$ 1,487,932	$ 775,931	$ 49,862
Distribution Poles												
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TDEPR	DEDSG	NCPP	$ 6,212,136	$ 3,104,364	$ 758,297	$ 49,777	$ 843,751	$ 707,590	$ 669,904	$ -	$ 22,449
Distribution Primary & Secondary Lines												
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	9,536,738	4,765,753	1,164,122	76,417	1,295,309	1,086,277	1,028,422	-	34,463
Primary Customer	TDEPR	DEDPLC	Cust08	15,606,193	13,494,077	1,620,986	2,502	99,433	4,703	18,047	-	71
Secondary Demand	TDEPR	DEDSLD	SICD	2,660,837	2,016,919	322,341	-	305,302	-	-	-	-
Secondary Customer	TDEPR	DEDSLC	Cust07	4,546,719	3,963,063	476,066	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		DEDLT		$ 32,350,488	$ 24,239,813	$ 3,583,514	$ 78,918	$ 1,700,044	$ 1,090,980	$ 1,046,469	$ -	$ 34,535
Distribution Line Transformers												
Demand	TDEPR	DEDLTD	SICDT	$ 3,259,675	$ 2,255,011	$ 360,392	$ -	$ 341,342	$ -	$ 284,733	$ -	$ -
Customer	TDEPR	DEDLTC	Cust09	1,816,969	1,571,796	188,813	-	11,582	-	2,102	-	-
Total Distribution Line Transformers		DEDLTT		$ 5,076,644	$ 3,826,807	$ 549,205	$ -	$ 352,924	$ -	$ 286,835	$ -	$ -
Distribution Services												
Customer	TDEPR	DEDSC	C02	$ 1,161,717	$ 1,000,612	$ 142,511	$ -	$ 14,659	$ -	$ 3,930	$ -	$ -
Distribution Meters												
Customer	TDEPR	DEDMC	MDT	$ 1,184,751	$ 797,297	$ 247,723	$ 8,097	$ 69,275	$ 16,173	$ 13,695	$ 11,430	$ 246
Distribution Street & Customer Lighting												
Customer	TDEPR	DEDSCL	C04	$ 3,830,233	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 277,122,836	$ 141,321,587	$ 30,910,647	$ 1,868,663	$ 31,666,501	$ 28,868,139	$ 24,459,931	$ 12,451,532	$ 748,439

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Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Depreciation Expenses										
Power Production Plant										
Production Demand - LOLP	TDEPR	DEPPLOLP	PDEPLOLPDA	$ 35,598	$ 1,240	$ 34,544	$ 82	$ 373	$ 83,870	$ 3,154
Production Energy	TDEPR	DEPPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		DEPPT		$ 35,598	$ 1,240	$ 34,544	$ 82	$ 373	$ 83,870	$ 3,154
Transmission Plant										
Transmission Demand	TDEPR	DETRB	NCPT	$ 118,159	$ 4,115	$ 1,889	$ 206	$ 21	$ -	$ -
Distribution Poles										
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TDEPR	DEDSG	NCPP	$ 53,198	$ 1,853	$ 851	$ 93	$ 9	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	81,669	2,845	1,306	142	14	-	-
Primary Customer	TDEPR	DEDPLC	Cust08	361,372	639	3,971	36	357	-	-
Secondary Demand	TDEPR	DEDSLD	SICD	15,460	538	247	27	3	-	-
Secondary Customer	TDEPR	DEDSLC	Cust07	106,131	188	1,166	-	105	-	-
Total Distribution Primary & Secondary Lines		DEDLT		$ 564,632	$ 4,210	$ 6,690	$ 205	$ 479	$ -	$ -
Distribution Line Transformers										
Demand	TDEPR	DEDLTD	SICDT	$ 17,285	$ 602	$ 276	$ 30	$ 3	$ -	$ -
Customer	TDEPR	DEDLTC	Cust09	42,093	74	463	4	42	-	-
Total Distribution Line Transformers		DEDLTT		$ 59,378	$ 677	$ 739	$ 34	$ 45	$ -	$ -
Distribution Services										
Customer	TDEPR	DEDSC	C02	$ -	$ -	$ -	$ 5	$ -	$ -	$ -
Distribution Meters										
Customer	TDEPR	DEDMC	MDT	$ -	$ 340	$ 2,111	$ 25	$ 18,339	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TDEPR	DEDSCL	C04	$ 3,830,233	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 4,661,198	$ 12,435	$ 46,824	$ 649	$ 19,265	$ 83,870	$ 3,154

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		1	2	3	4	5	6	7	8	9	10	11
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service Rate GS**	**Rate PS Primary**	**Rate PS Secondary**	**Rate TOD Primary**	**Rate TOD Secondary**	**Rate RTS Transmission**	**Special Contract Customer**
Regulatory Credits												
Power Production Plant												
Production Demand - LOLP	TRCTN	RCPLOLP	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	TRCTN	RCPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		RCPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant												
Transmission Demand	TRCTN	RCRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles												
Specific	TRCTN	RCPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TRCTN	RCSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TRCTN	RCPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TRCTN	RCPLD	NCPP	-	-	-	-	-	-	-	-	-
Primary Customer	TRCTN	RCPLC	Cust08	-	-	-	-	-	-	-	-	-
Secondary Demand	TRCTN	RCSLD	SICD	-	-	-	-	-	-	-	-	-
Secondary Customer	TRCTN	RCSLC	Cust07	-	-	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		RCLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers												
Demand	TRCTN	RCLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TRCTN	RCLTC	Cust09	-	-	-	-	-	-	-	-	-
Total Distribution Line Transformers		RCLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services												
Customer	TRCTN	RCSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TRCTN	RCMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TRCTN	RCSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TRCTN	RCCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TRCTN	RCCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TRCTN	RCSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RCT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Regulatory Credits										
Power Production Plant										
Production Demand - LOLP	TRCTN	RCPLOLP	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	TRCTN	RCPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		RCPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	TRCTN	RCRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	TRCTN	RCPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TRCTN	RCSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TRCTN	RCPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TRCTN	RCPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	TRCTN	RCPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	TRCTN	RCSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	TRCTN	RCSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		RCLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	TRCTN	RCLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TRCTN	RCLTC	Cust09	-	-	-	-	-	-	-
Total Distribution Line Transformers		RCLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	TRCTN	RCSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TRCTN	RCMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TRCTN	RCSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TRCTN	RCCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TRCTN	RCCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TRCTN	RCSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RCT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Accretion Expenses												
Power Production Plant												
Production Demand - LOLP	TACRTN	ACRPLOLP	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	TACRTN	ACRPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		ACRPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant												
Transmission Demand	TACRTN	ACRRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles												
Specific	TACRTN	ACRPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TACRTN	ACRSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	TACRTN	ACRPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRTN	ACRPLD	NCPP	-	-	-	-	-	-	-	-	-
Primary Customer	TACRTN	ACRPLC	Cust08	-	-	-	-	-	-	-	-	-
Secondary Demand	TACRTN	ACRSLD	SICD	-	-	-	-	-	-	-	-	-
Secondary Customer	TACRTN	ACRSLC	Cust07	-	-	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		ACRLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers												
Demand	TACRTN	ACRLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRTN	ACRLTC	Cust09	-	-	-	-	-	-	-	-	-
Total Distribution Line Transformers		ACRLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services												
Customer	TACRTN	ACRSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TACRTN	ACRMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	TACRTN	ACRSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	TACRTN	ACRCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TACRTN	ACRCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TACRTN	ACRSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	Name	Allocation Vector	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
		1	2	12	13	14	15	16	17	18
Accretion Expenses										
Power Production Plant										
Production Demand - LOLP	TACRTN	ACRPLOLP	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	TACRTN	ACRPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		ACRPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	TACRTN	ACRRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	TACRTN	ACRPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TACRTN	ACRSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TACRTN	ACRPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRTN	ACRPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	TACRTN	ACRPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	TACRTN	ACRSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	TACRTN	ACRSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		ACRLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	TACRTN	ACRLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRTN	ACRLTC	Cust09	-	-	-	-	-	-	-
Total Distribution Line Transformers		ACRLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	TACRTN	ACRSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TACRTN	ACRMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TACRTN	ACRSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TACRTN	ACRCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TACRTN	ACRCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TACRTN	ACRSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Property and Other Taxes												
Power Production Plant												
Production Demand - LOLP	PTAX	PTPPLOLP	PPTLOLPDA	$ 25,721,711	$ 12,270,751	$ 2,896,036	$ 196,089	$ 3,242,742	$ 3,081,883	$ 2,533,932	$ 1,410,720	$ 77,568
Production Energy	PTAX	PTPPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 25,721,711	$ 12,270,751	$ 2,896,036	$ 196,089	$ 3,242,742	$ 3,081,883	$ 2,533,932	$ 1,410,720	$ 77,568
Transmission Plant												
Transmission Demand	PTAX	PTTRB	NCPT	$ 4,076,189	$ 1,928,525	$ 471,077	$ 30,923	$ 524,164	$ 439,576	$ 416,164	$ 217,022	$ 13,946
Distribution Poles												
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	PTAX	PTDSG	NCPP	$ 1,563,612	$ 781,377	$ 190,866	$ 12,529	$ 212,375	$ 178,102	$ 168,617	$ -	$ 5,650
Distribution Primary & Secondary Lines												
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	2,400,424	1,199,554	293,013	19,234	326,033	273,419	258,857	-	8,675
Primary Customer	PTAX	PTDPLC	Cust08	3,928,124	3,396,498	408,007	630	25,028	1,184	4,543	-	18
Secondary Demand	PTAX	PTDSLD	SICD	669,740	507,664	81,134	-	76,845	-	-	-	-
Secondary Customer	PTAX	PTDSLC	Cust07	1,144,422	997,514	119,827	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		PTDLT		$ 8,142,711	$ 6,101,230	$ 901,981	$ 19,864	$ 427,906	$ 274,603	$ 263,399	$ -	$ 8,692
Distribution Line Transformers												
Demand	PTAX	PTDLTD	SICDT	$ 820,470	$ 567,593	$ 90,712	$ -	$ 85,917	$ -	$ 71,668	$ -	$ -
Customer	PTAX	PTDLTC	Cust09	457,336	395,626	47,525	-	2,915	-	529	-	-
Total Distribution Line Transformers		PTDLTT		$ 1,277,806	$ 963,218	$ 138,237	$ -	$ 88,832	$ -	$ 72,197	$ -	$ -
Distribution Services												
Customer	PTAX	PTDSC	C02	$ 292,408	$ 251,857	$ 35,871	$ -	$ 3,690	$ -	$ 989	$ -	$ -
Distribution Meters												
Customer	PTAX	PTDMC	MPTT	$ 298,205	$ 201,999	$ 62,762	$ 2,051	$ 17,551	$ 4,098	$ 3,470	$ 2,896	$ 62
Distribution Street & Customer Lighting												
Customer	PTAX	PTDSCL	C04	$ 964,081	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 42,336,722	$ 22,498,958	$ 4,696,829	$ 261,456	$ 4,517,259	$ 3,978,262	$ 3,458,769	$ 1,630,638	$ 105,919

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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12 Months Ended
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Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Property and Other Taxes										
Power Production Plant										
Production Demand - LOLP	PTAX	PTPPLOLP	PPTLOLPDA	$ 4,305	$ 150	$ 4,178	$ 10	$ 45	$ 3,190	$ 111
Production Energy	PTAX	PTPPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 4,305	$ 150	$ 4,178	$ 10	$ 45	$ 3,190	$ 111
Transmission Plant										
Transmission Demand	PTAX	PTTRB	NCPT	$ 33,048	$ 1,151	$ 528	$ 58	$ 6	$ -	$ -
Distribution Poles										
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	PTAX	PTDSG	NCPP	$ 13,390	$ 466	$ 214	$ 23	$ 2	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	20,556	716	329	36	4	-	-
Primary Customer	PTAX	PTDPLC	Cust08	90,958	161	999	9	90	-	-
Secondary Demand	PTAX	PTDSLD	SICD	3,891	136	62	7	1	-	-
Secondary Customer	PTAX	PTDSLC	Cust07	26,713	47	294	-	26	-	-
Total Distribution Primary & Secondary Lines		PTDLT		$ 142,119	$ 1,060	$ 1,684	$ 52	$ 121	$ -	$ -
Distribution Line Transformers										
Demand	PTAX	PTDLTD	SICDT	$ 4,351	$ 152	$ 70	$ 8	$ 1	$ -	$ -
Customer	PTAX	PTDLTC	Cust09	10,595	19	116	1	10	-	-
Total Distribution Line Transformers		PTDLTT		$ 14,946	$ 170	$ 186	$ 9	$ 11	$ -	$ -
Distribution Services										
Customer	PTAX	PTDSC	C02	$ -	$ -	$ -	$ 1	$ -	$ -	$ -
Distribution Meters										
Customer	PTAX	PTDMC	MPTT	$ -	$ 86	$ 535	$ 6	$ 2,689	$ -	$ -
Distribution Street & Customer Lighting										
Customer	PTAX	PTDSCL	C04	$ 964,081	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 1,171,890	$ 3,083	$ 7,325	$ 159	$ 2,875	$ 3,190	$ 111

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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12 Months Ended
June 30, 2022

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service Rate GS	6 Rate PS Primary	7 Rate PS Secondary	8 Rate TOD Primary	9 Rate TOD Secondary	10 Rate RTS Transmission	11 Special Contract Customer
Amortization of ITC												
Power Production Plant												
Production Demand - LOLP	OTAX	OTPPLOLP	PITCLOLPDA	$ (557,122)	$ (259,073)	$ (61,144)	$ (4,140)	$ (68,464)	$ (65,068)	$ (53,499)	$ (29,785)	$ (1,638)
Production Energy	OTAX	OTPPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ (557,122)	$ (259,073)	$ (61,144)	$ (4,140)	$ (68,464)	$ (65,068)	$ (53,499)	$ (29,785)	$ (1,638)
Transmission Plant												
Transmission Demand	OTAX	OTTRB	NCPT	$ (88,289)	$ (41,771)	$ (10,203)	$ (670)	$ (11,353)	$ (9,521)	$ (9,014)	$ (4,701)	$ (302)
Distribution Poles												
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	OTAX	OTDSG	NCPP	$ (33,867)	$ (16,924)	$ (4,134)	$ (271)	$ (4,600)	$ (3,858)	$ (3,652)	$ -	$ (122)
Distribution Primary & Secondary Lines												
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	(51,992)	(25,982)	(6,347)	(417)	(7,062)	(5,922)	(5,607)	-	(188)
Primary Customer	OTAX	OTDPLC	Cust08	(85,082)	(73,567)	(8,837)	(14)	(542)	(26)	(98)	-	(0)
Secondary Demand	OTAX	OTDSLD	SICD	(14,506)	(10,996)	(1,757)	-	(1,664)	-	-	-	-
Secondary Customer	OTAX	OTDSLC	Cust07	(24,788)	(21,606)	(2,595)	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ (176,368)	$ (132,150)	$ (19,537)	$ (430)	$ (9,268)	$ (5,948)	$ (5,705)	$ -	$ (188)
Distribution Line Transformers												
Demand	OTAX	OTDLTD	SICDT	$ (17,771)	$ (12,294)	$ (1,965)	$ -	$ (1,861)	$ -	$ (1,552)	$ -	$ -
Customer	OTAX	OTDLTC	Cust09	(9,906)	(8,569)	(1,029)	-	(63)	-	(11)	-	-
Total Distribution Line Transformers		OTDLTT		$ (27,677)	$ (20,863)	$ (2,994)	$ -	$ (1,924)	$ -	$ (1,564)	$ -	$ -
Distribution Services												
Customer	OTAX	OTDSC	C02	$ (6,333)	$ (5,455)	$ (777)	$ -	$ (80)	$ -	$ (21)	$ -	$ -
Distribution Meters												
Customer	OTAX	OTDMC	C03	$ (6,459)	$ (4,415)	$ (1,372)	$ (45)	$ (384)	$ (90)	$ (76)	$ (63)	$ (1)
Distribution Street & Customer Lighting												
Customer	OTAX	OTDSCL	C04	$ (20,882)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (916,996)	$ (480,652)	$ (100,161)	$ (5,556)	$ (96,073)	$ (84,484)	$ (73,531)	$ (34,549)	$ (2,252)

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12 Months Ended
June 30, 2022

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Amortization of ITC										
Power Production Plant										
Production Demand - LOLP	OTAX	OTPPLOLP	PITCLOLPDA	$ (91)	$ (3)	$ (88)	$ (0)	$ (1)	$ (13,728)	$ (399)
Production Energy	OTAX	OTPPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ (91)	$ (3)	$ (88)	$ (0)	$ (1)	$ (13,728)	$ (399)
Transmission Plant										
Transmission Demand	OTAX	OTTRB	NCPT	$ (716)	$ (25)	$ (11)	$ (1)	$ (0)	$ -	$ -
Distribution Poles										
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	OTAX	OTDSG	NCPP	$ (290)	$ (10)	$ (5)	$ (1)	$ (0)	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	(445)	(16)	(7)	(1)	(0)	-	-
Primary Customer	OTAX	OTDPLC	Cust08	(1,970)	(3)	(22)	(0)	(2)	-	-
Secondary Demand	OTAX	OTDSLD	SICD	(84)	(3)	(1)	(0)	(0)	-	-
Secondary Customer	OTAX	OTDSLC	Cust07	(579)	(1)	(6)	-	(1)	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ (3,078)	$ (23)	$ (36)	$ (1)	$ (3)	$ -	$ -
Distribution Line Transformers										
Demand	OTAX	OTDLTD	SICDT	$ (94)	$ (3)	$ (2)	$ (0)	$ (0)	$ -	$ -
Customer	OTAX	OTDLTC	Cust09	(229)	(0)	(3)	(0)	(0)	-	-
Total Distribution Line Transformers		OTDLTT		$ (324)	$ (4)	$ (4)	$ (0)	$ (0)	$ -	$ -
Distribution Services										
Customer	OTAX	OTDSC	C02	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -
Distribution Meters										
Customer	OTAX	OTDMC	C03	$ -	$ (2)	$ (12)	$ (0)	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	OTAX	OTDSCL	C04	$ (20,882)	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (25,380)	$ (67)	$ (156)	$ (3)	$ (4)	$ (13,728)	$ (399)

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service Rate GS	6 Rate PS Primary	7 Rate PS Secondary	8 Rate TOD Primary	9 Rate TOD Secondary	10 Rate RTS Transmission	11 Special Contract Customer
Other Expenses												
Power Production Plant												
Production Demand - LOLP	OT	OTPPLOLP	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	OT	OTPPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant												
Transmission Demand	OT	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles												
Specific	OT	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	OT	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	OT	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OT	OTDPLD	NCPP	-	-	-	-	-	-	-	-	-
Primary Customer	OT	OTDPLC	Cust08	-	-	-	-	-	-	-	-	-
Secondary Demand	OT	OTDSLD	SICD	-	-	-	-	-	-	-	-	-
Secondary Customer	OT	OTDSLC	Cust07	-	-	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers												
Demand	OT	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	OT	OTDLTC	Cust09	-	-	-	-	-	-	-	-	-
Total Distribution Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services												
Customer	OT	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	OT	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting												
Customer	OT	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	OT	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	OT	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	OT	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

12 Months Ended
June 30, 2022

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Other Expenses										
Power Production Plant										
Production Demand - LOLP	OT	OTPPLOLP	LOLP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy	OT	OTPPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	OT	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	OT	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	OT	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	OT	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OT	OTDPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	OT	OTDPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	OT	OTDSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	OT	OTDSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	OT	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	OT	OTDLTC	Cust09	-	-	-	-	-	-	-
Total Distribution Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	OT	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	OT	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	OT	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	OT	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	OT	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	OT	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

		1	2	3	4	5	6	7	8	9	10	11
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service Rate GS**	**Rate PS Primary**	**Rate PS Secondary**	**Rate TOD Primary**	**Rate TOD Secondary**	**Rate RTS Transmission**	**Special Contract Customer**
Interest Expenses												
Power Production Plant												
Production Demand - LOLP	INTLTD	INTPLOLP	LOLP	$ 45,829,811	$ 21,866,290	$ 5,160,692	$ 349,427	$ 5,778,517	$ 5,491,868	$ 4,515,428	$ 2,513,881	$ 138,224
Production Energy	INTLTD	INTPEB	E01	-	-	-	-	-	-	-	-	-
Total Power Production Plant		INTPT		$ 45,829,811	$ 21,866,290	$ 5,160,692	$ 349,427	$ 5,778,517	$ 5,491,868	$ 4,515,428	$ 2,513,881	$ 138,224
Transmission Plant												
Transmission Demand	INTLTD	INTTRB	NCPT	$ 7,262,774	$ 3,436,160	$ 839,345	$ 55,097	$ 933,932	$ 783,218	$ 741,503	$ 386,681	$ 24,848
Distribution Poles												
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	INTLTD	INTDSG	NCPP	$ 2,785,976	$ 1,392,224	$ 340,076	$ 22,324	$ 378,400	$ 317,335	$ 300,434	$ -	$ 10,068
Distribution Primary & Secondary Lines												
Primary Specific	INTLTD	INDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INDPLD	NCPP	4,276,970	2,137,312	522,077	34,271	580,911	487,166	461,219	-	15,456
Primary Customer	INTLTD	INDPLC	Cust08	6,998,958	6,051,730	726,968	1,122	44,593	2,109	8,094	-	32
Secondary Demand	INTLTD	INDSLD	SICD	1,193,314	904,534	144,561	-	136,920	-	-	-	-
Secondary Customer	INTLTD	INDSLC	Cust07	2,039,081	1,777,327	213,503	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		INDLT		$ 14,508,323	$ 10,870,903	$ 1,607,110	$ 35,393	$ 762,424	$ 489,275	$ 469,313	$ -	$ 15,488
Distribution Line Transformers												
Demand	INTLTD	INDLTD	SICDT	$ 1,461,877	$ 1,011,312	$ 161,626	$ -	$ 153,083	$ -	$ 127,695	$ -	$ -
Customer	INTLTD	INDLTC	Cust09	814,862	704,908	84,678	-	5,194	-	943	-	-
Total Distribution Line Transformers		INDLTT		$ 2,276,738	$ 1,716,220	$ 246,304	$ -	$ 158,277	$ -	$ 128,638	$ -	$ -
Distribution Services												
Customer	INTLTD	INDSC	C02	$ 520,999	$ 448,748	$ 63,912	$ -	$ 6,574	$ -	$ 1,762	$ -	$ -
Distribution Meters												
Customer	INTLTD	INDMC	C03	$ 531,329	$ 363,188	$ 112,844	$ 3,688	$ 31,557	$ 7,367	$ 6,239	$ 5,206	$ 112
Distribution Street & Customer Lighting												
Customer	INTLTD	INDSCL	C04	$ 1,717,757	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	INTLTD	INCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	INTLTD	INCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	INTLTD	INSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 75,433,705	$ 40,093,733	$ 8,370,283	$ 465,929	$ 8,049,680	$ 7,089,064	$ 6,163,317	$ 2,905,768	$ 188,740

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Interest Expenses										
Power Production Plant										
Production Demand - LOLP	INTLTD	INTPLOLP	LOLP	$ 7,672	$ 267	$ 7,445	$ 18	$ 80	$ -	$ -
Production Energy	INTLTD	INTPEB	E01	-	-	-	-	-	-	-
Total Power Production Plant		INTPT		$ 7,672	$ 267	$ 7,445	$ 18	$ 80	$ -	$ -
Transmission Plant										
Transmission Demand	INTLTD	INTTRB	NCPT	$ 58,884	$ 2,051	$ 941	$ 102	$ 10	$ -	$ -
Distribution Poles										
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	INTLTD	INTDSG	NCPP	$ 23,858	$ 831	$ 381	$ 42	$ 4	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	INTLTD	INDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INDPLD	NCPP	36,626	1,276	586	64	6	-	-
Primary Customer	INTLTD	INDPLC	Cust08	162,066	287	1,781	16	160	-	-
Secondary Demand	INTLTD	INDSLD	SICD	6,933	241	111	12	1	-	-
Secondary Customer	INTLTD	INDSLC	Cust07	47,597	84	523	-	47	-	-
Total Distribution Primary & Secondary Lines		INDLT		$ 253,222	$ 1,888	$ 3,000	$ 92	$ 215	$ -	$ -
Distribution Line Transformers										
Demand	INTLTD	INDLTD	SICDT	$ 7,752	$ 270	$ 124	$ 13	$ 1	$ -	$ -
Customer	INTLTD	INDLTC	Cust09	18,877	33	207	2	19	-	-
Total Distribution Line Transformers		INDLTT		$ 26,629	$ 303	$ 331	$ 15	$ 20	$ -	$ -
Distribution Services										
Customer	INTLTD	INDSC	C02	$ -	$ -	$ -	$ 2	$ -	$ -	$ -
Distribution Meters										
Customer	INTLTD	INDMC	C03	$ -	$ 155	$ 962	$ 11	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	INTLTD	INDSCL	C04	$ 1,717,757	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	INTLTD	INCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	INTLTD	INCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	INTLTD	INSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 2,088,022	$ 5,495	$ 13,061	$ 283	$ 330	$ -	$ -

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service Rate GS	6 Rate PS Primary	7 Rate PS Secondary	8 Rate TOD Primary	9 Rate TOD Secondary	10 Rate RTS Transmission	11 Special Contract Customer
Cost of Service Summary -- Unadjusted												
Operating Revenues												
Sales to Ultimate Consumers		REVUC	R01	$ 1,066,653,012	$ 431,824,736	$ 148,100,588	$ 10,054,862	$ 147,448,878	$ 136,688,085	$ 101,626,163	$ 64,286,867	$ 3,635,160
Sales for Resale			Energy	34,405,720	12,366,967	3,656,201	309,759	4,608,468	5,957,248	3,934,269	3,081,524	168,465
Transmission Revenue			PLTRT	12,094,529	5,722,158	1,397,741	91,752	1,555,255	1,304,274	1,234,808	643,931	41,379
Ancillary Services			LOLP	665,560	317,551	74,946	5,075	83,918	79,755	65,575	36,508	2,007
Curtailable Service Rider				(2,468,360)					(142,467)	-	(2,325,893)	
Forfeited Discounts		FORDIS	FDIS	2,706,693	2,147,240	209,025	7,005	278,420	13,168	50,533	1,301	-
Misc Service Revenues		REVMISC	MISCR	1,545,789	1,474,975	58,585	244	9,717	460	1,764	45	-
Rent From Electric Property			RFEP	3,799,537	2,011,449	421,907	23,601	405,923	361,224	311,611	149,299	9,665
Other Electric Revenue			OER	662,367	350,653	73,550	4,114	70,764	62,972	54,323	26,027	1,685
Electric Vehicle Charging Fees				11,088								
Total Operating Revenues		TOR		$ 1,120,075,935	$ 456,215,729	$ 153,992,543	$ 10,496,412	$ 154,461,344	$ 144,324,718	$ 107,279,046	$ 65,899,608	$ 3,858,362
Operating Expenses												
Operation and Maintenance Expenses				$ 643,436,661	$ 283,536,077	$ 72,621,803	$ 4,979,918	$ 76,879,988	$ 88,717,355	$ 63,134,706	$ 43,724,366	$ 2,482,051
Depreciation Expenses				277,122,836	141,321,587	30,910,647	1,868,663	31,666,501	28,868,139	24,459,931	12,451,532	748,439
Regulatory Credits				-	-	-	-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs			DET	-	-	-	-	-	-	-	-	-
Amortization Expense			DET	-	-	-	-	-	-	-	-	-
Property and Other Taxes			NPT	42,336,722	22,498,958	4,696,829	261,456	4,517,259	3,978,262	3,458,769	1,630,638	105,919
Amortization of Investment Tax Credit				(916,996)	(480,652)	(100,161)	(5,556)	(96,073)	(84,484)	(73,531)	(34,549)	(2,252)
Other Expenses				-	-	-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	7,757,584	(2,886,134)	3,518,578	274,593	3,138,581	1,478,672	951,208	490,049	31,482
Total Operating Expenses		TOE		$ 969,736,807	$ 443,989,835	$ 111,647,695	$ 7,379,074	$ 116,106,257	$ 122,957,944	$ 91,931,083	$ 58,262,037	$ 3,365,640
Utility Operating Income		TOM		$ 150,339,128	$ 12,225,894	$ 42,344,848	$ 3,117,338	$ 38,355,088	$ 21,366,773	$ 15,347,963	$ 7,637,571	$ 492,722
Net Cost Rate Base				$ 3,460,077,816	$ 1,830,420,621	$ 383,935,310	$ 21,476,777	$ 369,390,342	$ 328,714,071	$ 283,566,435	$ 135,862,169	$ 8,795,357
Taxable Income Unadjusted												
Total Operating Revenue				$ 1,120,075,935	$ 456,215,729	$ 153,992,543	$ 10,496,412	$ 154,461,344	$ 144,324,718	$ 107,279,046	$ 65,899,608	$ 3,858,362
Operating Expenses				$ 961,979,223	$ 446,875,970	$ 108,129,117	$ 7,104,481	$ 112,967,675	$ 121,479,273	$ 90,979,875	$ 57,771,988	$ 3,334,158
Interest Expense		INTEXP		$ 75,433,705	$ 40,093,733	$ 8,370,283	$ 465,929	$ 8,049,680	$ 7,089,064	$ 6,163,317	$ 2,905,768	$ 188,740
Taxable Income		TAXINC		$ 82,663,007	$ (30,753,973)	$ 37,493,143	$ 2,926,001	$ 33,443,989	$ 15,756,381	$ 10,135,854	$ 5,221,852	$ 335,464

Description	Ref	Name	Allocation Vector	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
		1	2	12	13	14	15	16	17	18
Cost of Service Summary -- Unadjusted										
Operating Revenues										
Sales to Ultimate Consumers		REVUC	R01	$ 22,160,940	$ 243,959	$ 318,742	$ 15,468	$ 1,533	$ 237,096	$ 9,936
Sales for Resale			Energy	302,375	10,532	9,822	35	56	-	-
Transmission Revenue			PLTRT	98,058	3,415	1,568	171	17	-	-
Ancillary Services			LOLP	111	4	108	0	1	-	-
Curtailable Service Rider										
Forfeited Discounts		FORDIS	FDIS	0	-	-	-	-	-	-
Misc Service Revenues		REVMISC	MISCR	-	-	-	-	-	-	-
Rent From Electric Property			RFEP	103,878	305	660	15	-	-	-
Other Electric Revenue			OER	18,109	53	115	3	-	-	-
Electric Vehicle Charging Fees								11,088	-	-
Total Operating Revenues		TOR		$ 22,683,471	$ 258,268	$ 331,014	$ 15,692	$ 12,695	$ 237,096	$ 9,936
Operating Expenses										
Operation and Maintenance Expenses				$ 6,925,874	$ 145,720	$ 178,418	$ 1,886	$ 26,596	$ 71,903	$ 10,000
Depreciation Expenses				4,661,198	12,435	46,824	649	19,265	83,870	3,154
Regulatory Credits				-	-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs			DET	-	-	-	-	-	-	-
Amortization Expense			DET	-	-	-	-	-	-	-
Property and Other Taxes			NPT	1,171,890	3,083	7,325	159	2,875	3,190	111
Amortization of Investment Tax Credit				(25,380)	(67)	(156)	(3)	(4)	(13,728)	(399)
Other Expenses				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	737,804	8,596	8,028	1,194	(3,413)	8,621	(275)
Total Operating Expenses		TOE		$ 13,471,385	$ 169,768	$ 240,439	$ 3,884	$ 45,319	$ 153,856	$ 12,591
Utility Operating Income		TOM		$ 9,212,086	$ 88,500	$ 90,576	$ 11,807	$ (32,624)	$ 83,240	$ (2,655)
Net Cost Rate Base				$ 94,529,248	$ 277,529	$ 600,893	$ 13,251	$ 120,516	$ 2,314,622	$ 60,677
Taxable Income Unadjusted										
Total Operating Revenue				$ 22,683,471	$ 258,268	$ 331,014	$ 15,692	$ 12,695	$ 237,096	$ 9,936
Operating Expenses				$ 12,733,581	$ 161,171	$ 232,411	$ 2,691	$ 48,732	$ 145,235	$ 12,866
Interest Expense		INTEXP		$ 2,088,022	$ 5,495	$ 13,061	$ 283	$ 330	$ -	$ -
Taxable Income		TAXINC		$ 7,861,868	$ 91,601	$ 85,542	$ 12,718	$ (36,366)	$ 91,861	$ (2,930)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2022

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Cost of Service Summary -- Pro-Forma												
Operating Revenues												
Total Pro-Forma Operating Revenue				$ 1,120,075,935	$ 456,215,729	$ 153,992,543	$ 10,496,412	$ 154,461,344	$ 144,324,718	$ 107,279,046	$ 65,899,608	$ 3,858,362
Operating Expenses												
Operation and Maintenance Expenses				$ 643,436,661	$ 283,536,077	$ 72,621,803	$ 4,979,918	$ 76,879,988	$ 88,717,355	$ 63,134,706	$ 43,724,366	$ 2,482,051
Depreciation and Amortization Expenses				277,122,836	141,321,587	30,910,647	1,868,663	31,666,501	28,868,139	24,459,931	12,451,532	748,439
Property and Other Taxes			NPT	42,336,722	22,498,958	4,696,829	261,456	4,517,259	3,978,262	3,458,769	1,630,638	105,919
Amortization of Investment Tax Credit				(916,996)	(480,652)	(100,161)	(5,556)	(96,073)	(84,484)	(73,531)	(34,549)	(2,252)
State and Federal Income Taxes			TAXINC	7,757,584	(2,886,134)	3,518,578	274,593	3,138,581	1,478,672	951,208	490,049	31,482
Specific Assignment of Interruptible Credit				(2,468,360)	-	-	-	-	(142,467)	-	(2,325,893)	-
Allocation of Interruptible Credits			INTCRE	2,468,360	1,177,704	277,952	18,820	311,227	295,789	243,198	135,396	7,445
Total Operating Expenses		TOE		$ 969,736,807	$ 445,167,540	$ 111,925,647	$ 7,397,894	$ 116,417,484	$ 123,111,266	$ 92,174,281	$ 56,071,540	$ 3,373,084
Net Operating Income -- Pro-Forma				$ 150,339,128	$ 11,048,190	$ 42,066,897	$ 3,098,518	$ 38,043,860	$ 21,213,452	$ 15,104,765	$ 9,828,068	$ 485,278
Cost of Service Summary -- Pro-Forma												
Net Operating Income -- Pro-Forma				$ 150,339,128	$ 11,048,190	$ 42,066,897	$ 3,098,518	$ 38,043,860	$ 21,213,452	$ 15,104,765	$ 9,828,068	$ 485,278
Adjusted Net Cost Rate Base				$ 3,460,077,816	$ 1,830,420,621	$ 383,935,310	$ 21,476,777	$ 369,390,342	$ 328,714,071	$ 283,566,435	$ 135,862,169	$ 8,795,357
Rate of Return				**4.34%**	**0.60%**	**10.96%**	**14.43%**	**10.30%**	**6.45%**	**5.33%**	**7.23%**	**5.52%**
Taxable Income Pro-Forma												
Total Operating Revenue				$ 1,120,075,935	$ 456,215,729	$ 153,992,543	$ 10,496,412	$ 154,461,344	$ 144,324,718	$ 107,279,046	$ 65,899,608	$ 3,858,362
Operating Expenses				$ 961,979,223	$ 448,053,674	$ 108,407,069	$ 7,123,301	$ 113,278,903	$ 121,632,594	$ 91,223,073	$ 55,581,491	$ 3,341,602
Interest Expense		INTEXP		$ 75,433,705	$ 40,093,733	$ 8,370,283	$ 465,929	$ 8,049,680	$ 7,089,064	$ 6,163,317	$ 2,905,768	$ 188,740
Interest Syncronization Adjustment			INTEXP	$ 6,215,728	$ 3,303,719	$ 689,710	$ 38,393	$ 663,293	$ 584,138	$ 507,857	$ 239,435	$ 15,552
Taxable Income		TXINCPF		$ 76,447,279	$ (35,235,396)	$ 36,525,482	$ 2,868,789	$ 32,469,469	$ 15,018,922	$ 9,384,800	$ 7,172,915	$ 312,467

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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Description	Ref	Name (1)	Allocation Vector (2)	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Pro-Forma Operating Revenue				$ 22,683,471	$ 258,268	$ 331,014	$ 15,692	$ 12,695	$ 237,096	$ 9,936
Operating Expenses										
Operation and Maintenance Expenses				$ 6,925,874	$ 145,720	$ 178,418	$ 1,886	$ 26,596	$ 71,903	$ 10,000
Depreciation and Amortization Expenses				4,661,198	12,435	46,824	649	19,265	83,870	3,154
Property and Other Taxes			NPT	1,171,890	3,083	7,325	159	2,875	3,190	111
Amortization of Investment Tax Credit				(25,380)	(67)	(156)	(3)	(4)	(13,728)	(399)
State and Federal Income Taxes			TAXINC	737,804	8,596	8,028	1,194	(3,413)	8,621	(275)
Specific Assignment of Interruptible Credit				-	-	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	413	14	401	1	-	-	-
Total Operating Expenses		TOE		$ 13,471,798	$ 169,782	$ 240,840	$ 3,885	$ 45,319	$ 153,856	$ 12,591
Net Operating Income -- Pro-Forma				$ 9,211,673	$ 88,486	$ 90,175	$ 11,806	$ (32,624)	$ 83,240	$ (2,655)
Cost of Service Summary -- Pro-Forma										
Net Operating Income -- Pro-Forma				$ 9,211,673	$ 88,486	$ 90,175	$ 11,806	$ (32,624)	$ 83,240	$ (2,655)
Adjusted Net Cost Rate Base				$ 94,529,248	$ 277,529	$ 600,893	$ 13,251	$ 120,516	$ 2,314,622	$ 60,677
Rate of Return				**9.74%**	**31.88%**	**15.01%**	**89.10%**	**-27.07%**	**3.60%**	**-4.38%**
Taxable Income Pro-Forma										
Total Operating Revenue				$ 22,683,471	$ 258,268	$ 331,014	$ 15,692	$ 12,695	$ 237,096	$ 9,936
Operating Expenses				$ 12,733,994	$ 161,186	$ 232,812	$ 2,692	$ 48,732	$ 145,235	$ 12,866
Interest Expense		INTEXP		$ 2,088,022	$ 5,495	$ 13,061	$ 283	$ 330	$ -	$ -
Interest Syncronization Adjustment			INTEXP	$ 172,053	$ 453	$ 1,076	$ 23	$ 27	$ -	$ -
Taxable Income		TXINCPF		$ 7,689,402	$ 91,134	$ 84,065	$ 12,694	$ (36,394)	$ 91,861	$ (2,930)

LOUISVILLE GAS AND ELECTRIC COMPANY
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Class Allocation

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		1	2	3	4	5	6	7	8	9	10	11
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service Rate GS**	**Rate PS Primary**	**Rate PS Secondary**	**Rate TOD Primary**	**Rate TOD Secondary**	**Rate RTS Transmission**	**Special Contract Customer**
Cost of Service Summary -- Pro-Forma (Adjusted for Proposed Increase)												
Operating Revenues												
Total Operating Revenue -- Actual				$ 1,120,075,935	$ 456,215,729	$ 153,992,543	$ 10,496,412	$ 154,461,344	$ 144,324,718	$ 107,279,046	$ 65,899,608	$ 3,858,362
Pro-Forma Adjustments:												
Proposed Increase				$ 130,962,989	$ 53,155,992	$ 19,105,822	$ 1,225,601	$ 17,917,377	$ 16,361,581	$ 12,216,545	$ 7,690,372	$ 435,109
Revenue Adjustment for Solar Share and EV				$ 175,526	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes in Late Payment Fees			FDIS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes to EVSE-R				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes in Rent on Electric Property			RFEP	$ 5,112	$ 2,706	$ 568	$ 32	$ 546	$ 486	$ 419	$ 201	$ 13
Changes in Miscellaneous Charges			MISCR	$ 89,459	$ 85,361	$ 3,390	$ 14	$ 562	$ 27	$ 102	$ 3	$ -
Total Pro-Forma Operating Revenue				$ 1,251,309,021	$ 509,459,788	$ 173,102,323	$ 11,722,059	$ 172,379,830	$ 160,686,811	$ 119,496,113	$ 73,590,184	$ 4,293,484
Operating Expenses												
Total Operating Expenses				$ 969,736,807	$ 445,167,540	$ 111,925,647	$ 7,397,894	$ 116,417,484	$ 123,111,266	$ 92,174,281	$ 56,071,540	$ 3,373,084
Total Pro-Forma Adjustments												
Incremental Uncollectible Accounts Expense			0.182%	238,844	96,904	34,780	2,231	32,612	29,779	22,235	13,997	792
Incremental Commission Fees			0.200%	262,466	106,488	38,220	2,451	35,837	32,724	24,434	15,381	870
Incremental Income Taxes			24.85%	32,610,703	13,230,857	4,748,676	304,567	4,452,645	4,065,891	3,035,874	1,911,066	108,125
Total Pro-forma Operating Expenses				$ 1,002,848,820	$ 458,601,789	$ 116,747,322	$ 7,707,143	$ 120,938,578	$ 127,239,660	$ 95,256,824	$ 58,011,984	$ 3,482,872
Net Operating Income -- Pro-Forma				$ 248,460,201	$ 50,858,000	$ 56,355,002	$ 4,014,916	$ 51,441,252	$ 33,447,152	$ 24,239,288	$ 15,578,200	$ 810,612
Net Cost Rate Base				$ 3,460,077,816	$ 1,830,420,621	$ 383,935,310	$ 21,476,777	$ 369,390,342	$ 328,714,071	$ 283,566,435	$ 135,862,169	$ 8,795,357
Rate of Return				**7.18%**	**2.78%**	**14.68%**	**18.69%**	**13.93%**	**10.18%**	**8.55%**	**11.47%**	**9.22%**

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Description	Ref	Name	Allocation Vector	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
		1	2	12	13	14	15	16	17	18
Cost of Service Summary -- Pro-Forma (Adjusted for Proposed Increase)										
Operating Revenues										
Total Operating Revenue -- Actual				$ 22,683,471	$ 258,268	$ 331,014	$ 15,692	$ 12,695	$ 237,096	$ 9,936
Pro-Forma Adjustments:										
Proposed Increase				$ 2,856,239	$ 3	$ (14)	$ (1,638)	$ -	$ -	$ -
Revenue Adjustment for Solar Share and EV				$ -	$ -	$ -	$ -	$ 55,206	$ 110,942	$ 9,378
Changes in Late Payment Fees			FDIS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes to EVSE-R				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Changes in Rent on Electric Property			RFEP	$ 140	$ 0	$ 1	$ 0	$ -	$ -	$ -
Changes in Miscellaneous Charges			MISCR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 25,539,850	$ 258,271	$ 331,001	$ 14,054	$ 67,901	$ 348,038	$ 19,314
Operating Expenses										
Total Operating Expenses				$ 13,471,798	$ 169,782	$ 240,840	$ 3,885	$ 45,319	$ 153,856	$ 12,591
Total Pro-Forma Adjustments										
Incremental Uncollectible Accounts Expense			0.182%	5,199	0	(0)	(3)	100	202	17
Incremental Commission Fees			0.200%	5,713	0	(0)	(3)	110	222	19
Incremental Income Taxes			24.85%	709,794	1	(3)	(407)	13,718	27,568	2,330
Total Pro-forma Operating Expenses				$ 14,192,504	$ 169,783	$ 240,836	$ 3,472	$ 59,248	$ 181,848	$ 14,957
Net Operating Income -- Pro-Forma				$ 11,347,346	$ 88,488	$ 90,165	$ 10,582	$ 8,653	$ 166,190	$ 4,357
Net Cost Rate Base				$ 94,529,248	$ 277,529	$ 600,893	$ 13,251	$ 120,516	$ 2,314,622	$ 60,677
Rate of Return				**12.00%**	**31.88%**	**15.01%**	**79.86%**	**7.18%**	**7.18%**	**7.18%**

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Allocation Factors												
Energy Allocation Factors												
Energy Usage by Class		E01	Energy	1.000000	0.359445	0.106267	0.009003	0.133945	0.173147	0.114349	0.089564	0.004896
Customer Allocation Factors												
Primary Distribution Plant -- Average Number of Customers		C01	Cust08	1.000000	0.86466	0.10387	0.00016	0.00637	0.00030	0.00116	-	0.00000
Customer Services -- Weighted cost of Services		C02		1.000000	0.86132	0.12267	-	0.01262	-	0.00338	-	-
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.68355	0.21238	0.00694	0.05939	0.01387	0.01174	0.00980	0.00021
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.74171	0.17820	0.00069	0.02733	0.00646	0.02480	0.00064	0.00002
Marketing/Economic Development		C06	Cust06	1.000000	0.86464	0.10386	0.00016	0.00637	0.00030	0.00116	0.00003	0.00000
Revenue per Billing Determinants		R01		1,066,653,012	431,824,736	148,100,588	10,054,862	147,448,878	136,688,085	101,626,163	64,286,867	3,635,160
Energy				11,352,592,561	4,049,109,440	1,197,088,880	103,621,086	1,508,873,858	1,992,826,476	1,288,132,009	1,050,890,542	56,355,100
Energy (Loss Adjusted)		Energy		11,999,883,068	4,313,299,004	1,275,194,546	108,036,539	1,607,322,352	2,077,743,868	1,372,177,906	1,074,760,983	58,756,477
O&M Customer Allocators												
Customers (Monthly Bills)				6,223,717	4,531,186	544,312	840	33,389	1,579	6,060	156	24
Average Customers (Bills/12)				518,643	377,599	45,359	70	2,782	132	505	13	2
Average Customers (Lighting = Lights)				518,643	377,599	45,359	70	2,782	132	505	13	2
Weighted Average Customers (Lighting = 9 Lights per Cust		Cust05		509,096	377,599	90,719	350	13,912	3,290	12,625	325	10
Street Lighting		Cust04		91,009						-		-
Average Customers		Cust01		518,643	377,599	45,359	70	2,782	132	505	13	2
Average Customers (Lighting = 9 Lights per Cust)		Cust06		436,714	377,599	45,359	70	2,782	132	505	13	2
Average Secondary Customers		Cust07		433,209	377,599	45,359	-	-	-	-	-	-
Average Primary Customers		Cust08		436,701	377,599	45,359	70	2,782	132	505	-	2
Average Transformer Customers		Cust09		436,498	377,599	45,359	-	2,782	-	505	-	-
Plant Customer Allocators												
Average Customers				518,575	377,557	45,332	70	2,783	132	505	13	2
Average Customers (Lighting = 9 Lights)				435,622	377,557	45,332	70	2,783	132	505	13	2
Weighted Average Customers		PCust05		507,988	377,557	90,664	350	13,915	3,300	12,625	325	10
Street Lighting (plant in service balance)		PCust04		126,670,914						-		-
Average Customers		PCust01		518,575	377,557	45,332	70	2,783	132	505	13	2
Average Customers (Lighting = 9 Lights per Cust)		PCust06		435,622	377,557	45,332	70	2,783	132	505	13	2
Average Secondary Customers		PCust07		432,318	377,557	45,332	70	-	132	-	-	-
Average Primary Customers		PCust08		435,622	377,557	45,332	70	2,783	132	505	13	2
Average Transformer Customers		PCust09		435,405	377,557	45,332	-	2,783	-	505	-	-
Demand Allocators												
Max Class Non-Coincident Peak Demands (Transmission)		NCPT		2,982,631	1,411,141	344,697	22,627	383,541	321,647	304,516	158,800	10,205
Max Class Non-Coincident Peak Demands (Primary)		NCPP		2,823,831	1,411,141	344,697	22,627	383,541	321,647	304,516	-	10,205
Sum of the Individual Customer Demands (Transformers)		SICDT		4,560,291	3,154,764	504,189	-	477,538	-	398,342	-	-
Sum of the Individual Customer Demands (Secondary)		SICD		4,161,949	3,154,764	504,189	-	477,538	-	-	-	-
LOLP Demand Allocator		LOLP		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705

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		1	2	12	13	14	15	16	17	18
Description	**Ref**	**Name**	**Allocation Vector**	**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**
Allocation Factors										
Energy Allocation Factors										
Energy Usage by Class		E01	Energy	0.008788	0.000306	0.000285	0.000001	0.000002	-	-
Customer Allocation Factors										
Primary Distribution Plant -- Average Number of Customers		C01	Cust08	0.02316	0.00004	0.00025	0.00000	0.00002	-	-
Customer Services -- Weighted cost of Services		C02		-	-	-	0.00000	-	-	-
Meter Costs -- Weighted Cost of Meters		C03		-	0.00029	0.00181	0.00002	-	-	-
Lighting Systems -- Lighting Customers		C04	Cust04	1.00000	-	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.01986	0.00004	0.00022	0.00001	0.00004	-	-
Marketing/Economic Development		C06	Cust06	0.02315	0.00004	0.00025	0.00000	0.00002	-	-
Revenue per Billing Determinants		R01		22,160,940	243,959	318,742	15,468	1,533	237,096	9,936
Energy				99,001,435	3,448,222	3,215,713	11,550	18,250	-	-
Energy (Loss Adjusted)		Energy		105,460,916	3,673,206	3,425,526	12,304	19,441	-	-
O&M Customer Allocators										
Customers (Monthly Bills)				1,092,108	1,932	12,000	12	120	-	-
Average Customers (Bills/12)				91,009	161	1,000	1	10	-	-
Average Customers (Lighting = Lights)				91,009	161	1,000	1	10	-	-
Weighted Average Customers (Lighting = 9 Lights per Cust		Cust05		10,112	18	111	5	20	-	-
Street Lighting		Cust04		91,009		-	-			
Average Customers		Cust01		91,009	161	1,000	1	10	-	-
Average Customers (Lighting = 9 Lights per Cust)		Cust06		10,112	18	111	1	10	-	-
Average Secondary Customers		Cust07		10,112	18	111	-	10	-	-
Average Primary Customers		Cust08		10,112	18	111	1	10	-	-
Average Transformer Customers		Cust09		10,112	18	111	1	10	-	-
Plant Customer Allocators										
Average Customers				91,009	161	1,000	1	10	-	-
Average Customers (Lighting = 9 Lights)				9,101	16	100	1	10	-	-
Weighted Average Customers		PCust05		9,101	16	100	5	20	-	-
Street Lighting (plant in service balance)		PCust04		126,670,914	-	-	-	-	-	-
Average Customers		PCust01		91,009	161	1,000	1	10	-	-
Average Customers (Lighting = 9 Lights per Cust)		PCust06		9,101	16	100	1	10	-	-
Average Secondary Customers		PCust07		9,101	16	100	-	10	-	-
Average Primary Customers		PCust08		9,101	16	100	1	10	-	-
Average Transformer Customers		PCust09		9,101	16	100	1	10	-	-
<u>Demand Allocators</u>										
Max Class Non-Coincident Peak Demands (Transmission)		NCPT		24,182	842	387	42	4	-	-
Max Class Non-Coincident Peak Demands (Primary)		NCPP		24,182	842	387	42	4	-	-
Sum of the Individual Customer Demands (Transformers)		SICDT		24,182	842	387	42	4	-	-
Sum of the Individual Customer Demands (Secondary)		SICD		24,182	842	387	42	4	-	-
LOLP Demand Allocator		LOLP		317	11	307	1	3	-	-

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
		1	2	3	4	5	6	7	8	9	10	11
Allocation Factors (Continued)												
Production Demand Cost Allocation												
Gross Plant Production Residual LOLP Demand Allocator		GPPLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Gross Plant Production LOLP Demand Costs				$ 3,865,573,604								
Customer Specific Assignment				$ 2,715,714		-	$ -	-	-	-	-	-
Gross Plant Production LOLP Demand Residual			GPPLOLPDRA	$ 3,862,857,890	$ 1,843,044,295	$ 434,979,325	$ 29,452,187	$ 487,053,951	$ 462,893,194	$ 380,591,965	$ 211,887,495	$ 11,650,517
Gross Plant Production LOLP Demand Total		GPPLOLPDT		$ 3,865,573,604	$ 1,843,044,295	$ 434,979,325	$ 29,452,187	$ 487,053,951	$ 462,893,194	$ 380,591,965	$ 211,887,495	$ 11,650,517
Gross Plant Production LOLP Demand Allocator		GPLOLPDA	GPPLOLPDT	1.000000	0.47678	0.11253	0.00762	0.12600	0.11975	0.09846	0.05481	0.00301
Net Plant Production Residual LOLP Demand Allocator		NPPLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Net Plant Production LOLP Demand Costs				$ 2,495,383,413								
Customer Specific Assignment				$ 2,559,063		-	$ -	-	-	-	-	-
Net Plant Production LOLP Demand Residual			NPPLOLPDRA	$ 2,492,824,350	$ 1,189,374,765	$ 280,705,913	$ 19,006,428	$ 314,311,316	$ 298,719,616	$ 245,608,030	$ 136,737,701	$ 7,518,447
Net Plant Production LOLP Demand Total		NPPLOLPDT		$ 2,495,383,413	$ 1,189,374,765	$ 280,705,913	$ 19,006,428	$ 314,311,316	$ 298,719,616	$ 245,608,030	$ 136,737,701	$ 7,518,447
Net Plant Production LOLP Demand Allocator		NPLOLPDA	NPPLOLPDT	1.000000	0.47663	0.11249	0.00762	0.12596	0.11971	0.09842	0.05480	0.00301
Rate Base Production Residual LOLP Demand Allocator		RBPLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Rate Base Production LOLP Demand Costs				$ 2,009,588,145								
Customer Specific Assignment				$ 2,375,299		-	$ -	-	-	-	-	-
Rate Base Production LOLP Demand Residual			RBPLOLPDRA	$ 2,007,212,847	$ 957,680,114	$ 226,023,352	$ 15,303,905	$ 253,082,297	$ 240,527,918	$ 197,762,668	$ 110,100,685	$ 6,053,825
Rate Base Production LOLP Demand Total		RBPLOLPDT		$ 2,009,588,145	$ 957,680,114	$ 226,023,352	$ 15,303,905	$ 253,082,297	$ 240,527,918	$ 197,762,668	$ 110,100,685	$ 6,053,825
Rate Base Production LOLP Demand Allocator		RBLOLPDA	RBPLOLPDT	1.000000	0.47656	0.11247	0.00762	0.12594	0.11969	0.09841	0.05479	0.00301
Production O&M Residual LOLP Demand Allocator		POMLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Production O&M LOLP Demand Costs				$ 111,958,098								
Customer Specific Assignment				$ 71,903		-	$ -	-	-	-	-	-
Production O&M LOLP Demand Residual			POMLOLPDRA	$ 111,886,195	$ 53,383,070	$ 12,599,009	$ 853,071	$ 14,107,331	$ 13,407,524	$ 11,023,700	$ 6,137,240	$ 337,453
Production O&M LOLP Demand Total		POMLOLPDT		$ 111,958,098	$ 53,383,070	$ 12,599,009	$ 853,071	$ 14,107,331	$ 13,407,524	$ 11,023,700	$ 6,137,240	$ 337,453
Production O&M LOLP Demand Allocator		POMLOLPDA	POMLOLPDT	1.000000	0.47681	0.11253	0.00762	0.12601	0.11975	0.09846	0.05482	0.00301
Production Depreciation Residual LOLP Demand Allocator		PDEPLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Production Depreciation LOLP Demand Costs				$ 212,733,072								
Customer Specific Assignment				$ 87,024		-	$ -	-	-	-	-	-
Production Depreciation LOLP Demand Residual			PDEPLOLPDRA	$ 212,646,048	$ 101,457,547	$ 23,945,130	$ 1,621,310	$ 26,811,781	$ 25,481,758	$ 20,951,166	$ 11,664,172	$ 641,348
Production Depreciation LOLP Demand Total		PDEPLOLPDT		$ 212,733,072	$ 101,457,547	$ 23,945,130	$ 1,621,310	$ 26,811,781	$ 25,481,758	$ 20,951,166	$ 11,664,172	$ 641,348
Production Depreciation LOLP Demand Allocator		PDEPLOLPDA	PDEPLOLPDT	1.000000	0.47692	0.11256	0.00762	0.12603	0.11978	0.09849	0.05483	0.00301
Production Prop Tax Residual LOLP Demand Allocator		PPTLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Production Prop Tax LOLP Demand Costs				$ 25,721,711								
Customer Specific Assignment				$ 3,301		-	$ -	-	-	-	-	-
Production Prop Tax LOLP Demand Residual			PPTLOLPDRA	$ 25,718,409	$ 12,270,751	$ 2,896,036	$ 196,089	$ 3,242,742	$ 3,081,883	$ 2,533,932	$ 1,410,720	$ 77,568
Production Prop Tax LOLP Demand Total		PPTLOLPDT		$ 25,721,711	$ 12,270,751	$ 2,896,036	$ 196,089	$ 3,242,742	$ 3,081,883	$ 2,533,932	$ 1,410,720	$ 77,568
Production Prop Tax LOLP Demand Allocator		PPTLOLPDA	PPTLOLPDT	1.000000	0.47706	0.11259	0.00762	0.12607	0.11982	0.09851	0.05485	0.00302
Production ITC Residual LOLP Demand Allocator		PITCLOLPDRA		1,891,712	902,573	213,017	14,423	238,519	226,687	186,383	103,765	5,705
Production ITC LOLP Demand Costs				$ (557,122)								
Customer Specific Assignment				$ (14,127)		-	$ -	-	-	-	-	-
Production ITC LOLP Demand Residual			PITCLOLPDRA	$ (542,995)	$ (259,073)	$ (61,144)	$ (4,140)	$ (68,464)	$ (65,068)	$ (53,499)	$ (29,785)	$ (1,638)
Production ITC LOLP Demand Total		PITCLOLPDT		$ (557,122)	$ (259,073)	$ (61,144)	$ (4,140)	$ (68,464)	$ (65,068)	$ (53,499)	$ (29,785)	$ (1,638)
Production ITC LOLP Demand Allocator		PITCLOLPDA	PITCLOLPDT	1.000000	0.46502	0.10975	0.00743	0.12289	0.11679	0.09603	0.05346	0.00294

Description	Ref	1 Name	2 Allocation Vector	12 Street Lighting Rate RLS, LS	13 Street Lighting Rate LE	14 Traffic Street Lighting Rate TLE	15 Outdoor Sports Lighting Rate OSL	16 Electric Vehicle Charging Rate EV	17 Solar Share Rate SSP	18 Business Solar Rate BS
Allocation Factors (Continued)										
Production Demand Cost Allocation										
Gross Plant Production Residual LOLP Demand Allocator		GPPLOLPDRA		317	11	307	1	3	-	-
Gross Plant Production LOLP Demand Costs										
Customer Specific Assignment				-	-				2,630,743	84,972
Gross Plant Production LOLP Demand Residual			GPPLOLPDRA	$ 646,656	$ 22,523	$ 627,517	$ 1,493	$ 6,773	$ -	$ -
Gross Plant Production LOLP Demand Total		GPPLOLPDT		$ 646,656	$ 22,523	$ 627,517	$ 1,493	$ 6,773	$ 2,630,743	$ 84,972
Gross Plant Production LOLP Demand Allocator		GPLOLPDA	GPPLOLPDT	0.00017	0.00001	0.00016	0.00000	0.00000	0.00068	0.00002
Net Plant Production Residual LOLP Demand Allocator		NPPLOLPDRA		317	11	307	1	3	-	-
Net Plant Production LOLP Demand Costs										
Customer Specific Assignment				-	-				2,486,734	72,329
Net Plant Production LOLP Demand Residual			NPPLOLPDRA	$ 417,308	$ 14,535	$ 404,956	$ 963	$ 4,371	$ -	$ -
Net Plant Production LOLP Demand Total		NPPLOLPDT		$ 417,308	$ 14,535	$ 404,956	$ 963	$ 4,371	$ 2,486,734	$ 72,329
Net Plant Production LOLP Demand Allocator		NPLOLPDA	NPPLOLPDT	0.00017	0.00001	0.00016	0.00000	0.00000	0.00100	0.00003
Rate Base Production Residual LOLP Demand Allocator		RBPLOLPDRA		317	11	307	1	3	-	-
Rate Base Production LOLP Demand Costs										
Customer Specific Assignment				-	-				2,314,622	60,677
Rate Base Production LOLP Demand Residual			RBPLOLPDRA	$ 336,015	$ 11,703	$ 326,069	$ 776	$ 3,520	$ -	$ -
Rate Base Production LOLP Demand Total		RBPLOLPDT		$ 336,015	$ 11,703	$ 326,069	$ 776	$ 3,520	$ 2,314,622	$ 60,677
Rate Base Production LOLP Demand Allocator		RBLOLPDA	RBPLOLPDT	0.00017	0.00001	0.00016	0.00000	0.00000	0.00115	0.00003
Production O&M Residual LOLP Demand Allocator		POMLOLPDRA		317	11	307	1	3	-	-
Production O&M LOLP Demand Costs										
Customer Specific Assignment				-	-				71,903	-
Production O&M LOLP Demand Residual			POMLOLPDRA	$ 18,730	$ 652	$ 18,176	$ 43	$ 196	$ -	$ -
Production O&M LOLP Demand Total		POMLOLPDT		$ 18,730	$ 652	$ 18,176	$ 43	$ 196	$ 71,903	$ -
Production O&M LOLP Demand Allocator		POMLOLPDA	POMLOLPDT	0.00017	0.00001	0.00016	0.00000	0.00000	0.00064	-
Production Depreciation Residual LOLP Demand Allocator		PDEPLOLPDRA		317	11	307	1	3	-	-
Production Depreciation LOLP Demand Costs										
Customer Specific Assignment				-	-				83,870	3,154
Production Depreciation LOLP Demand Residual			PDEPLOLPDRA	$ 35,598	$ 1,240	$ 34,544	$ 82	$ 373	$ -	$ -
Production Depreciation LOLP Demand Total		PDEPLOLPDT		$ 35,598	$ 1,240	$ 34,544	$ 82	$ 373	$ 83,870	$ 3,154
Production Depreciation LOLP Demand Allocator		PDEPLOLPDA	PDEPLOLPDT	0.00017	0.00001	0.00016	0.00000	0.00000	0.00039	0.00001
Production Prop Tax Residual LOLP Demand Allocator		PPTLOLPDRA		317	11	307	1	3	-	-
Production Prop Tax LOLP Demand Costs										
Customer Specific Assignment				-	-				3,190	111
Production Prop Tax LOLP Demand Residual			PPTLOLPDRA	$ 4,305	$ 150	$ 4,178	$ 10	$ 45	$ -	$ -
Production Prop Tax LOLP Demand Total		PPTLOLPDT		$ 4,305	$ 150	$ 4,178	$ 10	$ 45	$ 3,190	$ 111
Production Prop Tax LOLP Demand Allocator		PPTLOLPDA	PPTLOLPDT	0.00017	0.00001	0.00016	0.00000	0.00000	0.00012	0.00000
Production ITC Residual LOLP Demand Allocator		PITCLOLPDRA		317	11	307	1	3	-	-
Production ITC LOLP Demand Costs										
Customer Specific Assignment				-	-				(13,728)	(399)
Production ITC LOLP Demand Residual			PITCLOLPDRA	$ (91)	$ (3)	$ (88)	$ (0)	$ (1)	$ -	$ -
Production ITC LOLP Demand Total		PITCLOLPDT		$ (91)	$ (3)	$ (88)	$ (0)	$ (1)	$ (13,728)	$ (399)
Production ITC LOLP Demand Allocator		PITCLOLPDA	PITCLOLPDT	0.00016	0.00001	0.00016	0.00000	0.00000	0.02464	0.00072

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		1	2	3	4	5	6	7	8	9	10	11
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service Rate GS**	**Rate PS Primary**	**Rate PS Secondary**	**Rate TOD Primary**	**Rate TOD Secondary**	**Rate RTS Transmission**	**Special Contract Customer**
Meter Cost Allocation												
Meters Gross Plant Residual Allocator		MGPRA		38,550,020	26,350,722	8,187,269	267,611	2,289,550	534,525	452,630	377,746	8,124
Meters Gross Plant Costs				$ 44,815,612								
Customer Specific Assignment				$ 183,388		-	$ -	-	-	-	-	-
Meters Gross Plant Residual			MGPRA	$ 44,632,225	$ 30,508,190	$ 9,479,010	$ 309,833	$ 2,650,782	$ 618,860	$ 524,043	$ 437,345	$ 9,406
Meters Gross Plant Total		MGPT		$ 44,815,612	$ 30,508,190	$ 9,479,010	$ 309,833	$ 2,650,782	$ 618,860	$ 524,043	$ 437,345	$ 9,406
Meters Gross Plant Allocator		MGPA	MGPT	1.000000	0.68075	0.21151	0.00691	0.05915	0.01381	0.01169	0.00976	0.00021
Meters Net Plant Residual Allocator		MNPRA		38,550,020	26,350,722	8,187,269	267,611	2,289,550	534,525	452,630	377,746	8,124
Meters Net Plant Costs				$ 30,149,962								
Customer Specific Assignment				$ 139,194		-	$ -	-	-	-	-	-
Meters Net Plant Residual			MNPRA	$ 30,010,768	$ 20,513,748	$ 6,373,699	$ 208,332	$ 1,782,389	$ 416,122	$ 352,367	$ 294,071	$ 6,324
Meters Net Plant Total		MNPT		$ 30,149,962	$ 20,513,748	$ 6,373,699	$ 208,332	$ 1,782,389	$ 416,122	$ 352,367	$ 294,071	$ 6,324
Meters Net Plant Allocator		MNPA	MNPT	1.000000	0.68039	0.21140	0.00691	0.05912	0.01380	0.01169	0.00975	0.00021
Meters Rate Base Residual Allocator		MRBRA		38,550,020	26,350,722	8,187,269	267,611	2,289,550	534,525	452,630	377,746	8,124
Meters Rate Base Costs				$ 26,834,745								
Customer Specific Assignment				$ 105,259		-	$ -	-	-	-	-	-
Meters Rate Base Residual			MRBRA	$ 26,729,486	$ 18,270,840	$ 5,676,819	$ 185,554	$ 1,587,509	$ 370,625	$ 313,841	$ 261,918	$ 5,633
Meters Rate Base Total		MRBT		$ 26,834,745	$ 18,270,840	$ 5,676,819	$ 185,554	$ 1,587,509	$ 370,625	$ 313,841	$ 261,918	$ 5,633
Meters Rate Base Allocator		MRBA	MRBT	1.000000	0.68087	0.21155	0.00691	0.05916	0.01381	0.01170	0.00976	0.00021
Meters O&M Residual Allocator		MOMRA		38,550,020	26,350,722	8,187,269	267,611	2,289,550	534,525	452,630	377,746	8,124
Meters O&M Costs				$ 13,918,315								
Customer Specific Assignment				$ -		-	$ -	-	-	-	-	-
Meters O&M Residual			MOMRA	$ 13,918,315	$ 9,513,812	$ 2,955,978	$ 96,620	$ 826,632	$ 192,988	$ 163,420	$ 136,384	$ 2,933
Meters O&M Total		MOMT		$ 13,918,315	$ 9,513,812	$ 2,955,978	$ 96,620	$ 826,632	$ 192,988	$ 163,420	$ 136,384	$ 2,933
Meters O&M Allocator		MOMA	MOMT	1.000000	0.68355	0.21238	0.00694	0.05939	0.01387	0.01174	0.00980	0.00021
Meters Depreciation Residual Allocator		MDRA		38,550,020	26,350,722	8,187,269	267,611	2,289,550	534,525	452,630	377,746	8,124
Meters Depreciation Costs				$ 1,184,751								
Customer Specific Assignment				$ 18,339		-	$ -	-	-	-	-	-
Meters Depreciation Residual			MDRA	$ 1,166,412	$ 797,297	$ 247,723	$ 8,097	$ 69,275	$ 16,173	$ 13,695	$ 11,430	$ 246
Meters Depreciation Total		MDT		$ 1,184,751	$ 797,297	$ 247,723	$ 8,097	$ 69,275	$ 16,173	$ 13,695	$ 11,430	$ 246
Meters Depreciation Allocator		MDA	MDT	1.000000	0.67297	0.20909	0.00683	0.05847	0.01365	0.01156	0.00965	0.00021
Meters Prop Tax Residual Allocator		MPTRA		38,550,020	26,350,722	8,187,269	267,611	2,289,550	534,525	452,630	377,746	8,124
Meters Prop Tax Costs				$ 298,205								
Customer Specific Assignment				$ 2,689		-	$ -	-	-	-	-	-
Meters Prop Tax Residual			MPTRA	$ 295,516	$ 201,999	$ 62,762	$ 2,051	$ 17,551	$ 4,098	$ 3,470	$ 2,896	$ 62
Meters Prop Tax Total		MPTT		$ 298,205	$ 201,999	$ 62,762	$ 2,051	$ 17,551	$ 4,098	$ 3,470	$ 2,896	$ 62
Meters Prop Tax Allocator		MPTA	MPTT	1.000000	0.67738	0.21046	0.00688	0.05886	0.01374	0.01164	0.00971	0.00021
Customer Service O&M Cost Allocation												
Customer Service Residual Allocator		CSRA		436,714	377,599	45,359	70	2,782	132	505	13	2
Customer Service O&M Costs				$ 4,888,693								
Customer Specific Assignment				$ 34,000								
Customer Service O&M Residual			CSRA	$ 4,854,693	$ 4,197,542	$ 504,233	$ 778	$ 30,930	$ 1,463	$ 5,614	$ 145	$ 22
Customer Service O&M Total		CSOT		$ 4,888,693	$ 4,197,542	$ 504,233	$ 778	$ 30,930	$ 1,463	$ 5,614	$ 145	$ 22
Customer Service O&M Allocator		C10	CSOT	1.000000	0.85862	0.10314	0.00016	0.00633	0.00030	0.00115	0.00003	0.00000

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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12 Months Ended
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		1	2	12	13	14	15	16	17	18
Description	**Ref**	**Name**	**Allocation Vector**	**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**
Meter Cost Allocation										
Meters Gross Plant Residual Allocator		MGPRA		-	11,235	69,785	823	-	-	-
Meters Gross Plant Costs										
Customer Specific Assignment				-	-			$183,388		
Meters Gross Plant Residual			MGPRA	$ -	$ 13,008	$ 80,795	$ 953	$ -	$ -	$ -
Meters Gross Plant Total		MGPT		$ -	$ 13,008	$ 80,795	$ 953	$ 183,388	$ -	$ -
Meters Gross Plant Allocator		MGPA	MGPT	-	0.00029	0.00180	0.00002	0.00409	-	-
Meters Net Plant Residual Allocator		MNPRA		-	11,235	69,785	823	-	-	-
Meters Net Plant Costs										
Customer Specific Assignment				-	-			$139,194		
Meters Net Plant Residual			MNPRA	$ -	$ 8,747	$ 54,327	$ 641	$ -	$ -	$ -
Meters Net Plant Total		MNPT		$ -	$ 8,747	$ 54,327	$ 641	$ 139,194	$ -	$ -
Meters Net Plant Allocator		MNPA	MNPT	-	0.00029	0.00180	0.00002	0.00462	-	-
Meters Rate Base Residual Allocator		MRBRA		-	11,235	69,785	823	-	-	-
Meters Rate Base Costs										
Customer Specific Assignment				-	-			$105,259		
Meters Rate Base Residual			MRBRA	$ -	$ 7,790	$ 48,387	$ 571	$ -	$ -	$ -
Meters Rate Base Total		MRBT		$ -	$ 7,790	$ 48,387	$ 571	$ 105,259	$ -	$ -
Meters Rate Base Allocator		MRBA	MRBT	-	0.00029	0.00180	0.00002	0.00392	-	-
Meters O&M Residual Allocator		MOMRA		-	11,235	69,785	823	-	-	-
Meters O&M Costs										
Customer Specific Assignment				-	-			$0		
Meters O&M Residual			MOMRA	$ -	$ 4,056	$ 25,196	$ 297	$ -	$ -	$ -
Meters O&M Total		MOMT		$ -	$ 4,056	$ 25,196	$ 297	$ -	$ -	$ -
Meters O&M Allocator		MOMA	MOMT	-	0.00029	0.00181	0.00002	-	-	-
Meters Depreciation Residual Allocator		MDRA		-	11,235	69,785	823	-	-	-
Meters Depreciation Costs										
Customer Specific Assignment				-	-			$18,339		
Meters Depreciation Residual			MDRA	$ -	$ 340	$ 2,111	$ 25	$ -	$ -	$ -
Meters Depreciation Total		MDT		$ -	$ 340	$ 2,111	$ 25	$ 18,339	$ -	$ -
Meters Depreciation Allocator		MDA	MDT	-	0.00029	0.00178	0.00002	0.01548	-	-
Meters Prop Tax Residual Allocator		MPTRA		-	11,235	69,785	823	-	-	-
Meters Prop Tax Costs										
Customer Specific Assignment				-	-			$2,689		
Meters Prop Tax Residual			MPTRA	$ -	$ 86	$ 535	$ 6	$ -	$ -	$ -
Meters Prop Tax Total		MPTT		$ -	$ 86	$ 535	$ 6	$ 2,689	$ -	$ -
Meters Prop Tax Allocator		MPTA	MPTT	-	0.00029	0.00179	0.00002	0.00902	-	-
Customer Service O&M Cost Allocation										
Customer Service Residual Allocator		CSRA		10,112	18	111	1	10	-	-
Customer Service O&M Costs										
Customer Specific Assignment								$24,000	-	$10,000
Customer Service O&M Residual			CSRA	$ 112,410	$ 199	$ 1,235	$ 11	$ 111	$ -	$ -
Customer Service O&M Total		CSOT		$ 112,410	$ 199	$ 1,235	$ 11	$ 24,111	$ -	$ 10,000
Customer Service O&M Allocator		C10	CSOT	0.02299	0.00004	0.00025	0.00000	0.00493	-	0.00205

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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Description	Ref	Name (1)	Allocation Vector (2)	Total System (3)	Residential Rate RS (4)	General Service Rate GS (5)	Rate PS Primary (6)	Rate PS Secondary (7)	Rate TOD Primary (8)	Rate TOD Secondary (9)	Rate RTS Transmission (10)	Special Contract Customer (11)
Revenue Adjustment Allocators												
Forfeited Discounts		FDIS		2,707,235	2,147,670	209,067	7,006	278,476	13,171	50,543	1,301	-
Misc Service Revenue Allocator		MISCR		1,837,730	1,753,541	69,649	291	11,552	546	2,097	54	-
Rent From Electric Property		RFEP		3,457,582,001	1,830,420,621	383,935,310	21,476,777	369,390,342	328,714,071	283,566,435	135,862,169	8,795,357
Other Electric Revenue		OER		3,457,582,001	1,830,420,621	383,935,310	21,476,777	369,390,342	328,714,071	283,566,435	135,862,169	8,795,357
Expense Adjustment Allocators												
Interruptible Credit Allocator (Prod Plant)		INTCRE		3,862,851,117	1,843,044,295	434,979,325	29,452,187	487,053,951	462,893,194	380,591,965	211,887,495	11,650,517
O&M less fuel		OMLF		245,941,143	140,658,266	30,381,048	1,401,213	23,637,517	19,892,195	17,681,383	8,122,963	535,746
Base Rate Revenue at Current Rates				1,066,653,012	431,824,736	148,100,588	10,054,862	147,448,878	136,688,085	101,626,163	64,286,867	3,635,160
CSR Avoided Cost												
Interruptible Demands				433,038					38,819		394,219	
Avoided Cost per kW									3.67		5.90	
Avoided Cost				2,468,360					142,467		2,325,893	

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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12 Months Ended
June 30, 2022

		1	2	12	13	14	15	16	17	18
Description	**Ref**	**Name**	**Allocation Vector**	**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**
Revenue Adjustment Allocators										
Forfeited Discounts		FDIS		1	-	-	-	-	-	-
Misc Service Revenue Allocator		MISCR		-	-	-	-	-	-	-
Rent From Electric Property		RFEP		94,529,248	277,529	600,893	13,251	-	-	-
Other Electric Revenue		OER		94,529,248	277,529	600,893	13,251			
Expense Adjustment Allocators										
Interruptible Credit Allocator (Prod Plant)		INTCRE		646,656	22,523	627,517	1,493	-	-	-
O&M less fuel		OMLF		3,432,486	24,045	64,948	1,479	25,952	71,903	10,000.00
Base Rate Revenue at Current Rates				22,160,940	243,959	318,742	15,468	1,533	237,096	9,936
CSR Avoided Cost										
Interruptible Demands										
Avoided Cost per kW										
Avoided Cost										

Exhibit WSS-33

Gas Transmission Plant
Functional Assignment for the
Cost of Service Study
(Louisville Gas and Electric Company)

Account 367 Balance from July 2020	$	55,544,383
Engineering Estimate of Storage Related Transmission as of July 2020	$	64,813,109
Amount Included in Account 353	$	27,166,984
Storage Related Transmission Included in Account 367	$	37,646,125
Additional Storage Related Transmission Investment Included in Account 367 June 2022 Balance	$	35,597,685
Estimated Storage Related Transmission Included in Account 367 June 2022 Balance	$	73,243,810
Account 367 Forecasted Balance June 2022	$	242,931,122
Percent of Account 367 Forecasted Balance as of June 2022 Related to Storage		30.15%
Percent of Account 367 Forecasted Balance as of June 2022 Not Related to Storage		69.85%
Total		

Exhibit WSS-34

Zero Intercept Analysis of Distribution Mains (Louisville Gas and Electric Company)

Type of Main	Pipe Size	Net Cost of Plant	Quantity	Avg Cost	n	y	x	est y	y*n^.5	n^.5	xn^.5
PIPE, CAST IRON, 10	10	77,658.52	45,547	1.70501943	45,547	1.70502	10.00	24.776	363.88	213.42	2134.17431
PIPE, CAST IRON, 12	12	66,566.15	31,106	2.139977818	31,106	2.13998	12.00	27.549	377.43	176.37	2116.42718
PIPE, CAST IRON, 14	14	21,255.50	7,950	2.673647799	7,950	2.67365	14.00	30.322	238.39	89.16	1248.27882
PIPE, CAST IRON, 16	16	90,103.45	28,376	3.175340076	28,376	3.17534	16.00	33.095	534.89	168.45	2695.22838
PIPE, CAST IRON, 18	18	34,815.59	8,985	3.874856984	8,985	3.87486	18.00	35.868	367.29	94.79	1706.20632
PIPE, CAST IRON, 24	24	6,523.65	1,220	5.347254098	1,220	5.34725	24.00	44.186	186.77	34.93	838.283961
PIPE, CAST IRON, 4	4	232,011.34	284,533	0.815411007	284,533	0.81541	4.00	16.457	434.95	533.42	2133.66539
PIPE, CAST IRON, 6	6	30,092.75	29,657	1.01469299	29,657	1.01469	6.00	19.230	174.74	172.21	1033.27247
PIPE, CAST IRON, 8	8	38,666.69	27,960	1.382928827	27,960	1.38293	8.00	22.003	231.24	167.21	1337.69952
PIPE, PLASTIC, 1	1	71,808.18	3,000	23.93606	3,000	23.93606	1.00	12.298	1311	54.77	54.7722558
PIPE, PLASTIC, 2	2	147,496,076.13	8,888,931	16.59322995	8,888,931	16.59323	2.00	13.684	49472	2,981.43	5962.86206
PIPE, PLASTIC, 4	4	106,786,944.81	4,014,837	26.59807728	4,014,837	26.59808	4.00	16.457	53295	2,003.71	8014.82327
PIPE, PLASTIC, 6	6	39,493,513.89	878,431	44.95915318	878,431	44.95915	6.00	19.230	42138	937.25	5623.47899
PIPE, PLASTIC, 8	8	25,702,840.01	290,920	88.3501994	290,920	88.35020	8.00	22.003	47653	539.37	4314.96002
PIPE, PLASTIC, 10	10	19,616.26	46	426.4404348	46	426.44043	10.00	24.776	2892.3	6.78	67.8232998
PIPE, STEEL, 1	1	1,792,624.37	72,839	24.61077678	72,839	24.61078	1.00	12.298	6642.1	269.89	269.887013
PIPE, STEEL, 1 1/2	1.5	25,393.20	652	38.94662577	652	38.94663	1.50	12.991	994.47	25.53	38.301436
PIPE, STEEL, 1 1/4	1.25	11,352.19	403	28.16920596	403	28.16921	1.25	12.645	565.49	20.07	25.0935749
PIPE, STEEL, 10	10	92,683.96	5,185	17.87540212	5,185	17.87540	10.00	24.776	1287.2	72.01	720.069441
PIPE, STEEL, 12	12	14,656,557.38	521,083	28.12710716	521,083	28.12711	12.00	27.549	20304	721.86	8662.32948
PIPE, STEEL, 16	16	8,006,093.90	257,321	31.11325504	257,321	31.11326	16.00	33.095	15783	507.27	8116.29078
PIPE, STEEL, 2	2	18,128,004.78	4,099,373	4.422140844	4,099,373	4.42214	2.00	13.684	8953.5	2,024.69	4049.38168
PIPE, STEEL, 2 1/2	2.5	9,087.67	480	18.93264583	480	18.93265	2.50	14.378	414.79	21.91	54.7722558
PIPE, STEEL, 20	20	4,002,792.28	154,201	25.95827705	154,201	25.95828	20.00	38.641	10193	392.68	7853.68703
PIPE, STEEL, 22	22	56,616.99	3,497	16.19016014	3,497	16.19016	22.00	41.413	957.41	59.14	1300.97963
PIPE, STEEL, 24	24	122,746.10	871	140.9254879	871	140.92549	24.00	44.186	4159.1	29.51	708.305019
PIPE, STEEL, 4	4	38,014,082.75	4,721,852	8.050672226	4,721,852	8.05067	4.00	16.457	17494	2,172.98	8691.92913
PIPE, STEEL, 6	6	11,373,827.64	825,294	13.7815465	825,294	13.78155	6.00	19.230	12520	908.46	5450.7416
PIPE, STEEL, 8	8	30,776,488.82	1,967,573	15.6418536	1,967,573	15.64185	8.00	22.003	21941	1,402.70	11221.6163
PIPE, WROUGHT IRON, 1 1/2	1.5	906.81	2,276	0.398422671	2,276	0.39842	1.50	12.991	19.008	47.71	71.5611627
PIPE, WROUGHT IRON, 1 1/4	1.25	3,455.93	8,636	0.400177165	8,636	0.40018	1.25	12.645	37.188	92.93	116.162602
PIPE, WROUGHT IRON, 10	10	49,167.84	26,553	1.851686815	26,553	1.85169	10.00	24.776	301.73	162.95	1629.50913
PIPE, WROUGHT IRON, 12	12	14,816.90	5,786	2.560819219	5,786	2.56082	12.00	27.549	194.79	76.07	912.789132
PIPE, WROUGHT IRON, 16	16	46,942.53	14,045	3.342294767	14,045	3.34229	16.00	33.095	396.1	118.51	1896.18564
PIPE, WROUGHT IRON, 2	2	1,268.21	3,617	0.350624827	3,617	0.35062	2.00	13.684	21.087	60.14	120.283
PIPE, WROUGHT IRON, 3	3	1,348.82	2,388	0.564832496	2,388	0.56483	3.00	15.071	27.602	48.87	146.601501
PIPE, WROUGHT IRON, 4	4	43,896.76	39,947	1.098875009	39,947	1.09888	4.00	16.457	219.63	199.87	799.469824
PIPE, WROUGHT IRON, 8	8	120,947.42	85,164	1.420170729	85,164	1.42017	8.00	22.003	414.45	291.83	2334.62974

Weighted Linear Regression Statistics

	Estimate	Standard Error	LINEST Array	
			1.386452713	10.91149336
Size Coefficient ($ per Foot)	1.3864527	0.6555649	0.655564862	3.183258346
Zero Intercept ($ per Foot)	10.9114934	3.1832583	0.691792497	9792.588193
			40.40221228	36
R-Square	69.18%		7748722800	3452212207

Plant Classification

Total All Distribution Mains		27,360,535
Zero Intercept		10.9114934
Zero Intercept Cost	$	298,544,296
Total Cost of Sample	$	447,519,596
Customer Percentage of Total		66.71%

Louisville Gas and Electric Company
Zero Intercept Distribution Mains

Nominal Size (in inches)	Total Distribution Mains: Feet of Pipe	Total Distribution Mains: Installed Costs	Total Distribution Mains: Unit Costs	High Pressure Mains	High Pressure Mains: Feet of Pipe	High Pressure Mains: Installed Costs	Low and Medium Pressure Mains: Feet of Pipe	Low and Medium Pressure Mains: Installed Costs
				Category II 1"	0			
				Category III 1"	2,806			
1	75,839	1,864,433	24.5841		2,806	68,986	73,033	1,795,447
1.25	9,039	14,808	1.6382		0	0	9,039	14,808
1.5	2,928	26,300	8.9822		0	0	2,928	26,300
				Category II 2"	0			
				Category III 2"	63,404			
2	12,991,921	165,625,349	12.7483		63,404	808,294	12,928,517	164,817,055
2.5	480	9,088	18.9326		0	0	480	9,088
3	2,388	1,349	0.5648	*Category II 3"*	104	59	2,284	1,290
				Category II 4"	0			
				Category III 4"	430,844			
4	9,061,169	145,076,936	16.0108		430,844	6,898,167	8,630,325	138,178,769
				Category II 6"	0			
				Category III 6"	150,219			
6	1,733,382	50,897,434	29.3631		150,219	4,410,904	1,583,163	46,486,530
				Category II 8"	0			
				Category III 8"	554,720			
8	2,371,617	56,638,943	23.8820		554,720	13,247,824	1,816,897	43,391,119
10	77,331	239,127	3.0922	*Category II 10"*	268	830	77,063	238,297
				Category II 12"	0			
				Category III 12"	351,421			
12	557,975	14,737,940	26.4133		351,421	9,282,182	206,554	5,455,758
14	7,950	21,256	2.6736		0	0	7,950	21,256
16	299,742	8,143,140	27.1672	*Category II 16"*	191,692	5,207,740	108,050	2,935,400
18	8,985	34,816	3.8749		0	0	8,985	34,816
				Category II 20"	0			
				Category III 20"	72,502			
20	154,201	4,002,792	25.9583		72,502	1,882,028	81,699	2,120,764
22	3,497	56,617	16.1902	*Category II 22"*	3,497	56,622	0	-5
24	2,091	129,270	61.8220	*Category II 24"*	942	58,236	1,149	71,034
Total All Mains	**27,360,535**	**$ 447,519,596**			**1,822,421**	**$ 41,921,872**	**25,538,114**	**$ 405,597,724**
Zero Intercept		**$ 10.911**				**$ 10.911**		**$ 10.911**
Customer-Related Costs*		**$ 298,544,296**				**$ 19,885,332**		**$ 278,658,964**
Portion of Total		**66.71%**				**4.44%**		**62.27%**
Demand-Related Costs**		**$ 148,975,300**				**$ 22,036,540**		**$ 126,938,761**
Portion of Total		**33.29%**				**4.92%**		**28.36%**
Notes:						**9.37%**		**90.63%**

* Customer-Related Costs calculated by applying the zero intercept unit cost of $7.7583297 to total feet of pipe. 9.37%

** Demand-Related Costs equal Total All Distribution Mains less Customer-Related Costs

Exhibit WSS-35

Analysis of Low-, Medium-, and High-Pressure Distribution Mains for the Cost of Service Study (Louisville Gas and Electric Company)

Louisville Gas and Electric Company
Allocation of High Pressure and Low/Medium Pressure Mains
12 Months Ended February 2020

	Residential Rate RGS	Commercial Rate CGS	Industrial Rate IGS	Rate AAGS	IntraCompany	Rate FT (1)	Total
Actual							
Total Mcf Sales and Transportation	17,994,912	9,880,285	1,523,000	326,085	246,837	13,791,319	43,762,438
Non-Temp. Sensitive Sales & Transportation - Jul. & Aug.	640,087	525,363	183,067	32,292	27,294	1,638,503	3,046,606
Annualized Non-Temperature Sensitive Sales & Transport.	3,840,523	3,152,175	1,098,400	193,753	163,765	9,831,019	18,279,635
Non-Temperature Sensitive Sales & Transportation per Day	10,522	8,636	3,009	531	449	26,934	50,081
Temperature Sensitive Sales & Transportation	14,154,388	6,728,110	424,600	132,332	-	3,960,300	25,482,803
Degree Days	3,585	3,585	3,677	3,677	3,677	3,677	
Temperature Sensitive Sales & Transportation per Degree Day	3,949	1,877	115	36	-	1,077	7,054
Calculated Daily Customer Deliveries (Demands) @ -14 Degrees (79 Degree Days)							
Total Demands	322,467	156,915	12,132	3,374	449	112,021	607,357.06
Percentage of Total	53.09%	25.84%	2.00%	0.56%	0.07%	18.44%	100.00%
Demands - High Pressure Distribution System	322,467	156,915	12,132	3,374	449	112,021	607,357
Demands - Low/Medium Pressure Distribution System	322,467	156,489	11,621	3,281	-	14,146	508,004

(1) Rate FT includes LG&E Transportation Special Contract

	Residential Rate RGS	Commercial Rate CGS	Industrial Rate IGS	Rate AAGS	Rate FT (1)	Total
Actual						
Total Mcf Sales and Transportation	-	253,887	186,563	33,884	11,336,626	11,810,960
Non-Temp. Sensitive Sales & Transportation - Jul. & Aug.	-	279	38,652	6,601	1,295,371	1,340,903
Annualized Non-Temperature Sensitive Sales & Transport.	-	1,674	186,563	33,884	7,772,228	7,994,349
Non-Temperature Sensitive Sales & Transportation per Day	-	5	511	93	21,294	21,902
Temperature Sensitive Sales & Transportation	-	252,213	-	-	3,564,398	3,816,611
Degree Days	3,585	3,585	3,677	3,677	3,677	
Temperature Sensitive Sales & Transportation per Degree Day	-	-	-	-	969	969
Calculated Daily Customer Deliveries (Demands) @ -14 Degrees (79 Degree Days)						
Total Demands/MDQ	-	426	511	93	97,875	98,483
Percentage of Total	0%	0%	1%	0%	99%	100%

Exhibit WSS-36

Gas Cost of Service Study
Functional Assignment and Classification
(Louisville Gas and Electric Company)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	**Description**		**Name**	**Vector**		**Company**	**Demand**	**Commodity**	**Demand**	**Commodity**	**Demand**	**Demand**
3												
4	**Gas Plant at Original Cost**											
5												
6	**Underground Storage Plant**											
7	350-357	Underground Storage Plant	PT350	F003	$	197,915,357	-	-	197,915,357	-	-	-
8	358	Asset Retire Obligation Gas Plant	PT350	F003	$	-	-	-	-	-	-	-
9												
10	Total Storage Plant		PTST		$	197,915,357	$ -	$ -	$ 197,915,357	$ -	$ -	$ -
11												
12	**Transmission Plant**											
13	365-372	Transmission	PT365	F005	$	223,442,488	-	-	-	-	186,703,851	36,738,637
14												
15	**Distribution Plant**											
16	374	Land and Land Rights	PT374	F008	$	1,270,241	-	-	-	-	-	-
17	375	Structures & Improvements	PT375	F008		1,284,811	-	-	-	-	-	-
18	376	Mains	PT376	F009		491,695,737	-	-	-	-	-	-
19	378	Meas. & Reg. Sta. Equip. - General	PT378	F008		42,772,631	-	-	-	-	-	-
20	379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008		19,032,139	-	-	-	-	-	-
21	380	Services	PT380	F010		422,716,510	-	-	-	-	-	-
22	381	Meters	PT381	F011		69,454,781	-	-	-	-	-	-
23	382	Meter Installations	PT382	F011			-	-	-	-	-	-
24	383	House Regulators	PT383	F011		27,617,358	-	-	-	-	-	-
25	384	House Regulator Installations	PT384	F011			-	-	-	-	-	-
26	385	Industrial Meas. & Reg. Equip.	PT385	F011		2,155,727	-	-	-	-	-	-
27	387	Other Equipment	PT387	F011		1,990,118	-	-	-	-	-	-
28	388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008		-	-	-	-	-	-	-
29	388	Asset Retire Obligation Gas Plant-Mains	PT388	F009		-	-	-	-	-	-	-
30												
31	Sub-Total Distribution Plant		PTDSUB		$	1,079,990,052	$ -	$ -	$ -	$ -	$ -	$ -
32												
33	U-T-D Subtotal		PTSUB		$	1,501,347,897	-	-	197,915,357	-	186,703,851	36,738,637
34												
35												
36	117 & 352	Gas Stored Underground/Non-Current	PT117	F003	$	11,788,845	-	-	11,788,845	-	-	-
37	301-303	Intangible Plant	PT301	PTSUB		387	-	-	51	-	48	9
38	392-396	General Plant	PT389	PTSUB		16,821,099	-	-	2,217,443	-	2,091,830	411,620
39	301-399	Common Utility Plant	PTCP	PTSUB		103,860,678	-	-	13,691,446	-	12,915,853	2,541,516
40												
41	Total Plant in Service		PTIS		$	1,633,818,906	-	-	225,613,142	-	201,711,581	39,691,782
42												
43												
44												
45												
46												
47												
48												
49												
50												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

A	B	C	D	M	N	O	P	Q	R
Description		**Name**	**Vector**	**Distribution Commodity**	**Distribution Structures & Equipment Demand**	**Distribution Mains - Low & Med. Pressure Demand**	**Distribution Mains - Low & Med. Pressure Customer**	**Distribution Mains - High Pressure Demand**	**Distribution Mains - High Pressure Customer**
<u>Gas Plant at Original Cost</u>									
Underground Storage Plant									
350-357	Underground Storage Plant	PT350	F003	-	-	-	-	-	-
358	Asset Retire Obligation Gas Plant	PT350	F003	-	-	-	-	-	-
Total Storage Plant		PTST		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
365-372	Transmission	PT365	F005	-	-	-	-	-	-
Distribution Plant									
374	Land and Land Rights	PT374	F008	-	1,270,241	-	-	-	-
375	Structures & Improvements	PT375	F008	-	1,284,811	-	-	-	-
376	Mains	PT376	F009	-	-	139,469,306	306,166,312	24,211,839	21,848,279
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	-	42,772,631	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	19,032,139	-	-	-	-
380	Services	PT380	F010	-	-	-	-	-	-
381	Meters	PT381	F011	-	-	-	-	-	-
382	Meter Installations	PT382	F011	-	-	-	-	-	-
383	House Regulators	PT383	F011	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	-	-	-	-	-
387	Other Equipment	PT387	F011	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$ -	$ 64,359,821	$ 139,469,306	$ 306,166,312	$ 24,211,839	$ 21,848,279
U-T-D Subtotal		PTSUB		-	64,359,821	139,469,306	306,166,312	24,211,839	21,848,279
117 & 352	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	-	17	36	79	6	6
392-396	General Plant	PT389	PTSUB	-	721,087	1,562,614	3,430,287	271,269	244,788
301-399	Common Utility Plant	PTCP	PTSUB	-	4,452,302	9,648,248	21,180,061	1,674,934	1,511,427
Total Plant in Service		PTIS		-	69,533,228	150,680,204	330,776,740	26,158,049	23,604,500

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

A	B	C	D	S	T	U	V
Description		**Name**	**Vector**	**Services Customer**	**Meters Customer**	**Customer Accounts Customer**	**Customer Service Expense Customer**
Gas Plant at Original Cost							
Underground Storage Plant							
350-357	Underground Storage Plant	PT350	F003	-	-	-	-
358	Asset Retire Obligation Gas Plant	PT350	F003	-	-	-	-
Total Storage Plant		PTST		$ -	$ -	$ -	$ -
Transmission Plant							
365-372	Transmission	PT365	F005	-	-	-	-
Distribution Plant							
374	Land and Land Rights	PT374	F008	-	-	-	-
375	Structures & Improvements	PT375	F008	-	-	-	-
376	Mains	PT376	F009	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	-	-	-
380	Services	PT380	F010	422,716,510	-	-	-
381	Meters	PT381	F011	-	69,454,781	-	-
382	Meter Installations	PT382	F011	-	-	-	-
383	House Regulators	PT383	F011	-	27,617,358	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	2,155,727	-	-
387	Other Equipment	PT387	F011	-	1,990,118	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$ 422,716,510	$ 101,217,983	$ -	$ -
U-T-D Subtotal		PTSUB		422,716,510	101,217,983	-	-
117 & 352	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	109	26	-	-
392-396	General Plant	PT389	PTSUB	4,736,115	1,134,046	-	-
301-399	Common Utility Plant	PTCP	PTSUB	29,242,805	7,002,087	-	-
Total Plant in Service		PTIS		456,695,539	109,354,142	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1											Transmission Non-	Transmission Storage
2	Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Storage Related Demand	Related Demand
3												
51												
52	Gas Plant at Original Cost (Continued)											
53												
54	Construction Work in Progress											
55		Underground Storage	CWIPUS	F003	$	5,350,413	-	-	5,350,413	-	-	-
56		Transmission	CWIPTR	F005		21,538,079	-	-	-	-	17,996,767	3,541,313
57		Distribution Mains	CWIPDM	F009		17,858,627	-	-	-	-	-	-
58		Other Distribution	CWIPOD	PTDSUB		-	-	-	-	-	-	-
59		General	CWIPCO	PTSUB		231,748	-	-	30,550	-	28,820	5,671
60		Common		PTSUB		5,017,612	-	-	661,447	-	623,978	122,783
61			CWIP		$	49,996,479	$ -	$ -	$ 6,042,410	$ -	$ 18,649,564	$ 3,669,767
62												
63			PTT		$	1,683,815,385	-	-	231,655,552	-	220,361,145	43,361,549
64												
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A / B	C	D	M	N	O	P	Q	R
1				Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	**Description**	**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3									
51									
52	**Gas Plant at Original Cost (Continued)**								
53									
54	**Construction Work in Progress**								
55	Underground Storage	CWIPUS	F003	-	-	-	-	-	-
56	Transmission	CWIPTR	F005	-	-	-	-	-	-
57	Distribution Mains	CWIPDM	F009	-	-	5,065,593	11,120,108	879,386	793,540
58	Other Distribution	CWIPOD	PTDSUB	-	-	-	-	-	-
59	General	CWIPCO	PTSUB	-	9,935	21,528	47,260	3,737	3,373
60	Common		PTSUB	-	215,095	466,116	1,023,230	80,918	73,019
61		CWIP		$ -	$ 225,030	$ 5,553,237	$ 12,190,598	$ 964,041	$ 869,931
62									
63		PTT		-	69,758,257	156,233,441	342,967,338	27,122,089	24,474,431
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	**Description**		**Name**	**Vector**	**Customer**	**Customer**	**Customer**	**Customer**
3								
51								
52	**Gas Plant at Original Cost (Continued)**							
53								
54	**Construction Work in Progress**							
55		Underground Storage	CWIPUS	F003	-	-	-	-
56		Transmission	CWIPTR	F005	-	-	-	-
57		Distribution Mains	CWIPDM	F009	-	-	-	-
58		Other Distribution	CWIPOD	PTDSUB	-	-	-	-
59		General	CWIPCO	PTSUB	65,251	15,624	-	-
60		Common		PTSUB	1,412,749	338,278	-	-
61			CWIP		$ 1,477,999	$ 353,902	$ -	$ -
62								
63			PTT		458,173,538	109,708,044	-	-
64								
65						$ 1,188,437,139		
66								
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A / B	C	D	F	G	H	I	J	K	L
1									Transmission Non-	Transmission Storage
2	**Description**	**Name**	**Vector**	**Total Company**	**Procurement Demand**	**Procurement Commodity**	**Storage Demand**	**Storage Commodity**	**Storage Related Demand**	**Related Demand**
3										
94										
95	**Net Cost Rate Base**									
96										
97	**Total Gas Utility Plant at Original Cost**			$ 1,683,815,385	$ -	$ -	$ 231,655,552	$ -	$ 220,361,145	$ 43,361,549
98										
99	**Less:**									
100										
101	**Reserve for Depreciation**									
102	Underground Storage	DEPRUS	PTST	$ 41,894,825	-	-	41,894,825	-	-	-
103	Transmission	DEPTR	F005	15,896,893	-	-	-	-	13,283,110	2,613,783
104	Distribution	DEPRDI	DEPRDIS	341,471,693	-	-	-	-	-	-
105	General & Intangible	DEPRGE	PT389	6,431,222	-	-	847,797	-	799,771	157,375
106	Common	DEPRCO	PTCP	43,213,014	-	-	5,696,560	-	5,373,862	1,057,441
107										
108	Total Depreciation Reserve	DEPR		$ 448,907,648	$ -	$ -	$ 48,439,183	$ -	$ 19,456,743	$ 3,828,599
109										
110	Customer Advances For Construction	CAD	CADAL	$ 5,484,694	-	-	-	-	-	-
111	Accum. Deferred Income Taxes	DIT	PTSUB	232,827,481	-	-	30,692,509	-	28,953,840	5,697,390
118										
119	**PLUS:**									
120										
121	Materials and Supplies	MSP	PTSUB	$ 1,613,256	-	-	212,668	-	200,620	39,477
122	Prepayments	PPY	PTSUB	4,065,204	-	-	535,896	-	505,539	99,477
123	Gas Stored Underground	GSU	F003	20,578,072	-	-	20,578,072	-	-	-
124	Cash Working Capital	CWC	OMT	29,497,882	55,522	417,406	1,354,413	2,672,923	4,880,525	960,365
125										
126	**Adjustments:**			$ (182,557,761)						
127										
128	N/A		PTSUB	$ -	-	-	-	-	-	-
129	N/A		PTSUB	-	-	-	-	-	-	-
130	N/A		PTSUB	-	-	-	-	-	-	-
131	N/A		PTSUB	-	-	-	-	-	-	-
132										
133	**Net Cost Rate Base**	NCRB		$ 1,052,349,977	$ 55,522	$ 417,406	$ 175,204,909	$ 2,672,923	$ 177,537,247	$ 34,934,880
134										
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A / B	C	D	M	N	O	P	Q	R
1				Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	**Description**	**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3									
94									
95	**Net Cost Rate Base**								
96									
97	**Total Gas Utility Plant at Original Cost**			$ -	$ 69,758,257	$ 156,233,441	$ 342,967,338	$ 27,122,089	$ 24,474,431
98									
99	**Less:**								
100									
101	**Reserve for Depreciation**								
102	Underground Storage	DEPRUS	PTST	-	-	-	-	-	-
103	Transmission	DEPTR	F005	-	-	-	-	-	-
104	Distribution	DEPRDI	DEPRDIS	-	6,067,346	61,313,202	102,633,587	8,922,192	6,430,014
105	General & Intangible	DEPRGE	PT389	-	275,694	597,435	1,311,504	103,715	93,590
106	Common	DEPRCO	PTCP	-	1,852,457	4,014,319	8,812,327	696,885	628,855
107									
108	Total Depreciation Reserve	DEPR		$ -	$ 8,195,496	$ 65,924,956	$ 112,757,418	$ 9,722,792	$ 7,152,459
109									
110	Customer Advances For Construction	CAD	CADAL	-	-	836,544	1,836,402	145,224	131,047
111	Accum. Deferred Income Taxes	DIT	PTSUB	-	9,980,855	21,628,756	47,479,955	3,754,747	3,388,209
118									
119	**PLUS:**								
120									
121	Materials and Supplies	MSP	PTSUB	-	69,157	149,865	328,987	26,017	23,477
122	Prepayments	PPY	PTSUB	-	174,267	377,641	829,007	65,558	59,159
123	Gas Stored Underground	GSU	F003	-	-	-	-	-	-
124	Cash Working Capital	CWC	OMT	532,971	1,401,159	2,188,083	4,803,332	379,851	342,770
125									
126	**Adjustments:**								
127									
128	N/A		PTSUB	-	-	-	-	-	-
129	N/A		PTSUB	-	-	-	-	-	-
130	N/A		PTSUB	-	-	-	-	-	-
131	N/A		PTSUB	-	-	-	-	-	-
132									
133	**Net Cost Rate Base**	NCRB		$ 532,971	$ 53,226,490	$ 70,558,775	$ 186,854,890	$ 13,970,753	$ 14,228,121
134									
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A / B	C	D	S	T	U	V
1				Services	Meters	Customer Accounts	Customer Service Expense
2	**Description**	**Name**	**Vector**	**Customer**	**Customer**	**Customer**	**Customer**
3							
94							
95	**Net Cost Rate Base**						
96							
97	**Total Gas Utility Plant at Original Cost**			$ 458,173,538	$ 109,708,044	$ -	$ -
98							
99	**Less:**						
100							
101	**Reserve for Depreciation**						
102	Underground Storage	DEPRUS	PTST	-	-	-	-
103	Transmission	DEPTR	F005	-	-	-	-
104	Distribution	DEPRDI	DEPRDIS	129,229,023	26,876,329	-	-
105	General & Intangible	DEPRGE	PT389	1,810,762	433,581	-	-
106	Common	DEPRCO	PTCP	12,166,970	2,913,338	-	-
107							
108	Total Depreciation Reserve	DEPR		$ 143,206,754	$ 30,223,248	$ -	$ -
109							
110	Customer Advances For Construction	CAD	CADAL	2,535,476	-	-	-
111	Accum. Deferred Income Taxes	DIT	PTSUB	65,554,440	15,696,780	-	-
118							
119	**PLUS:**						
120							
121	Materials and Supplies	MSP	PTSUB	454,225	108,763	-	-
122	Prepayments	PPY	PTSUB	1,144,591	274,068	-	-
123	Gas Stored Underground	GSU	F003	-	-	-	-
124	Cash Working Capital	CWC	OMT	3,226,505	1,762,102	4,090,962	428,992
125							
126	**Adjustments:**						
127							
128	N/A		PTSUB	-	-	-	-
129	N/A		PTSUB	-	-	-	-
130	N/A		PTSUB	-	-	-	-
131	N/A		PTSUB	-	-	-	-
132							
133	**Net Cost Rate Base**	NCRB		$ 251,702,188	$ 65,932,949	$ 4,090,962	$ 428,992
134							
135							
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139							
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	Description		Name	Vector		Company	Demand	Commodity	Demand	Commodity	Demand	Demand
3												
141												
142	**Labor Expenses**											
143												
144	807 & 810	Procurement Expenses	LB807	DMCM		707,310	83,038	624,272	-	-	-	-
145												
146	**Storage Expenses**											
147	**Operation**											
148	814	Operations Supervision and Engineer	LB814	OSE		788,735	-	-	131,016	657,719	-	-
149	815	Maps and Records	LB815	F003		-	-	-	-	-	-	-
150	816	Well Expenses	LB816	F003		48,170	-	-	48,170	-	-	-
151	817	Lines Expenses	LB817	F003		220,271	-	-	220,271	-	-	-
152	818	Compressor Station Exp - Payroll	LB818	F004		778,006	-	-	-	778,006	-	-
153	819	Compressor Station Fuel and Power	LB819	F004		-	-	-	-	-	-	-
154	820	Measurement and Regulator Station	LB820	F003		-	-	-	-	-	-	-
155	821	Purification of Natural Gas	LB821	F004		569,604	-	-	-	569,604	-	-
156	823	Gas losses	LB823	F004		-	-	-	-	-	-	-
157	824	Other Expenses	LB824	F004		-	-	-	-	-	-	-
158	825	Storage Well Royalities	LB825	F003		-	-	-	-	-	-	-
159	826	Rents	LB826	F003		-	-	-	-	-	-	-
160												
161	Total Storage Operation Labor		LBSO		$	2,404,786	$ -	$ -	$ 399,457	$ 2,005,329	$ -	$ -
162												
163												
164												
165	**Storage Expense**											
166	Maintenance											
167	830	Maintenance Super and Eng.	LB830	MSE		437,056	-	-	235,421	201,635	-	-
168	831	Maintenance of Structures	LB831	F003		-	-	-	-	-	-	-
169	832	Maintenance of Resevoirs	LB832	F003		83,454	-	-	83,454	-	-	-
170	833	Maintenance of Lines	LB833	F003		432,731	-	-	432,731	-	-	-
171	834	Main of Compressor Station Equipment	LB834	F004		286,492	-	-	-	286,492	-	-
172	835	Main of Meas and Reg Sta. Equip	LB835	F003		-	-	-	-	-	-	-
173	836	Main of Purification Equip	LB836	F004		280,992	-	-	-	280,992	-	-
174	837	Main of Other Equipment	LB837	F003		146,389	-	-	146,389	-	-	-
175												
176	Total Maintenance Labor		LBSM		$	1,667,114	$ -	$ -	$ 897,995	$ 769,119	$ -	$ -
177												
178												
179	Total Storage Labor		LBS		$	4,071,900	-	-	1,297,453	2,774,447	-	-
180												
181												
182												
183												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1						Distribution Structures	Distribution Mains -	Distribution Mains -	Distribution Mains -	Distribution Mains -
					Distribution	& Equipment	Low & Med. Pressure	Low & Med. Pressure	High Pressure	High Pressure
2	Description		Name	Vector	Commodity	Demand	Demand	Customer	Demand	Customer
3										
141										
142	Labor Expenses									
143										
144	807 & 810	Procurement Expenses	LB807	DMCM	-	-	-	-	-	-
145										
146	Storage Expenses									
147	Operation									
148	814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-
149	815	Maps and Records	LB815	F003	-	-	-	-	-	-
150	816	Well Expenses	LB816	F003	-	-	-	-	-	-
151	817	Lines Expenses	LB817	F003	-	-	-	-	-	-
152	818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-	-	-
153	819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-
154	820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-
155	821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-
156	823	Gas losses	LB823	F004	-	-	-	-	-	-
157	824	Other Expenses	LB824	F004	-	-	-	-	-	-
158	825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-
159	826	Rents	LB826	F003	-	-	-	-	-	-
160										
161	Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -	$ -	$ -
162										
163										
164										
165	Storage Expense									
166	Maintenance									
167	830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-	-	-
168	831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-
169	832	Maintenance of Resevoirs	LB832	F003	-	-	-	-	-	-
170	833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-
171	834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-	-	-
172	835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-	-	-
173	836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-
174	837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-
175										
176	Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -	$ -	$ -
177										
178										
179	Total Storage Labor		LBS		-	-	-	-	-	-
180										
181										
182										
183										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
141								
142	**Labor Expenses**							
143								
144	807 & 810	Procurement Expenses	LB807	DMCM	-	-	-	-
145								
146	**Storage Expenses**							
147	**Operation**							
148	814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-
149	815	Maps and Records	LB815	F003	-	-	-	-
150	816	Well Expenses	LB816	F003	-	-	-	-
151	817	Lines Expenses	LB817	F003	-	-	-	-
152	818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-
153	819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-
154	820	Measurement and Regulator Station	LB820	F003	-	-	-	-
155	821	Purification of Natural Gas	LB821	F004	-	-	-	-
156	823	Gas losses	LB823	F004	-	-	-	-
157	824	Other Expenses	LB824	F004	-	-	-	-
158	825	Storage Well Royalities	LB825	F003	-	-	-	-
159	826	Rents	LB826	F003	-	-	-	-
160								
161	Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -
162								
163								
164								
165	**Storage Expense**							
166	Maintenance							
167	830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-
168	831	Maintenance of Structures	LB831	F003	-	-	-	-
169	832	Maintenance of Resevoirs	LB832	F003	-	-	-	-
170	833	Maintenance of Lines	LB833	F003	-	-	-	-
171	834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-
172	835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-
173	836	Main of Purification Equip	LB836	F004	-	-	-	-
174	837	Main of Other Equipment	LB837	F003	-	-	-	-
175								
176	Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -
177								
178								
179	Total Storage Labor		LBS		-	-	-	-
180								
181								
182								
183								

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	Description		Name	Vector		Company	Demand	Commodity	Demand	Commodity	Demand	Demand
3												
184												
185	**Labor Expenses (Continued)**											
186												
187												
188	**Transmission**											
189	850-867	Transmission Expenses	LB850	F005	$	2,919,136	-	-	-	-	2,439,169	479,967
190												
191	**Distribution Expenses**											
192	Operation											
193	870	Operation Supr and Engr	LB870	DOES	$	-	-	-	-	-	-	-
194	871	Dist Load Dispatching	LB871	F007		838,265	-	-	-	-	-	-
195	872	Compr. Station Labor and Exp.	LB872	F007		-	-	-	-	-	-	-
196	873	Compr. Station Fuel and Power	LB873	F007		-	-	-	-	-	-	-
197	874.01	Other Mains/Serv. Expenses	LB874.01	CADAL		1,811,145	-	-	-	-	-	-
198	874.02	Leak Survey-Mains	LB874.02	F009		-	-	-	-	-	-	-
199	874.03	Leak Survey - Service	LB874.03	F010		-	-	-	-	-	-	-
200	874.04	Locate Main per Request	LB874.04	CADAL		-	-	-	-	-	-	-
201	874.05	Check Stop Box Access	LB874.05	F010		-	-	-	-	-	-	-
202	874.06	Patrolling Mains	LB874.06	F009		-	-	-	-	-	-	-
203	874.07	Check/Grease Valves	LB874.07	F009		-	-	-	-	-	-	-
204	874.08	Opr. Odor Equipment	LB874.08	F007		-	-	-	-	-	-	-
205	874.09	Locate and Inspect Valve Boxes	LB874.09	F009		-	-	-	-	-	-	-
206	874.1	Cut Grass - Right of Way	LB874.10	F009		-	-	-	-	-	-	-
207	875	Meas and Reg Station Exp.- General	LB875	F008	$	884,412	-	-	-	-	-	-
208	876	Meas and Reg Station Exp.- Industrial	LB876	F011	$	424,143	-	-	-	-	-	-
209	877	Meas and Reg Station Exp. - City Gate	LB877	F008	$	136,159	-	-	-	-	-	-
210	878	Meter and House Reg. Expense	LB878	F011	$	965,746	-	-	-	-	-	-
211	879	Customer Installation Expense	LB879	F011	$	168,892	-	-	-	-	-	-
212	880	Other Expenses	LB880	PTDSUB	$	2,738,849	-	-	-	-	-	-
213	881	Rents	LB881	PTDSUB	$	-	-	-	-	-	-	-
214												
215	Total Operations Distribution Labor		LBDO		$	7,967,611	$ -	$ -	$ -	$ -	$ -	$ -
216												
217	Total Operations Transmission and Distribution Labor		LBTDO		$	10,886,747	$ -	$ -	$ -	$ -	$ 2,439,169	$ 479,967
218												
219												
220												
221												
222												
223												
224												
225												
226												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1						Distribution Structures	Distribution Mains -	Distribution Mains -	Distribution Mains -	Distribution Mains -
					Distribution	& Equipment	Low & Med. Pressure	Low & Med. Pressure	High Pressure	High Pressure
2	**Description**		**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3										
184										
185	**Labor Expenses (Continued)**									
186										
187										
188	**Transmission**									
189	850-867	Transmission Expenses	LB850	F005	-	-	-	-	-	-
190										
191	**Distribution Expenses**									
192	Operation									
193	870	Operation Supr and Engr	LB870	DOES	-	-	-	-	-	-
194	871	Dist Load Dispatching	LB871	F007	838,265	-	-	-	-	-
195	872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-	-	-
196	873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-	-
197	874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	-	-	276,242	606,413	47,956	43,274
198	874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-	-	-
199	874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-	-	-
200	874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-	-	-
201	874.05	Check Stop Box Access	LB874.05	F010	-	-	-	-	-	-
202	874.06	Patrolling Mains	LB874.06	F009	-	-	-	-	-	-
203	874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-	-	-
204	874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-	-	-
205	874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-	-	-
206	874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-	-	-
207	875	Meas and Reg Station Exp.- General	LB875	F008	-	884,412	-	-	-	-
208	876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	-	-	-	-	-
209	877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	136,159	-	-	-	-
210	878	Meter and House Reg. Expense	LB878	F011	-	-	-	-	-	-
211	879	Customer Installation Expense	LB879	F011	-	-	-	-	-	-
212	880	Other Expenses	LB880	PTDSUB	-	163,216	353,693	776,436	61,401	55,407
213	881	Rents	LB881	PTDSUB	-	-	-	-	-	-
214										
215	Total Operations Distribution Labor		LBDO		$ 838,265	$ 1,183,787	$ 629,935	$ 1,382,849	$ 109,357	$ 98,681
216										
217	Total Operations Transmission and Distribution Labor		LBTDO		$ 838,265	$ 1,183,787	$ 629,935	$ 1,382,849	$ 109,357	$ 98,681
218										
219										
220										
221										
222										
223										
224										
225										
226										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
184								
185	**Labor Expenses (Continued)**							
186								
187								
188	**Transmission**							
189	850-867	Transmission Expenses	LB850	F005	-	-	-	-
190								
191	**Distribution Expenses**							
192	Operation							
193	870	Operation Supr and Engr	LB870	DOES	-	-	-	-
194	871	Dist Load Dispatching	LB871	F007	-	-	-	-
195	872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-
196	873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-
197	874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	837,260	-	-	-
198	874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-
199	874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-
200	874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-
201	874.05	Check Stop Box Access	LB874.05	F010	-	-	-	-
202	874.06	Patrolling Mains	LB874.06	F009	-	-	-	-
203	874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-
204	874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-
205	874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-
206	874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-
207	875	Meas and Reg Station Exp.- General	LB875	F008	-	-	-	-
208	876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	424,143	-	-
209	877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-
210	878	Meter and House Reg. Expense	LB878	F011	-	965,746	-	-
211	879	Customer Installation Expense	LB879	F011	-	168,892	-	-
212	880	Other Expenses	LB880	PTDSUB	1,072,007	256,688	-	-
213	881	Rents	LB881	PTDSUB	-	-	-	-
214								
215	Total Operations Distribution Labor		LBDO		$ 1,909,267	$ 1,815,469	$ -	$ -
216								
217	Total Operations Transmission and Distribution Labor		LBTDO		$ 1,909,267	$ 1,815,469	$ -	$ -
218								
219								
220								
221								
222								
223								
224								
225								
226								

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	Description		Name	Vector		Company	Demand	Commodity	Demand	Commodity	Demand	Demand
3												
227												
228	Labor Expenses (Continued)											
229												
230												
231	Maintenance Expense -- Distribution											
232												
233	885	Maintenance Supr and Engr	LB885	DMES	$	-	-	-	-	-	-	-
234	886	Maintenance Structures	LB886	F008		-	-	-	-	-	-	-
235	887	Maintenance Mains	LB887	F009		3,944,944	-	-	-	-	-	-
236	888	Maintenance Comp. Station Equip.	LB888	F007		-	-	-	-	-	-	-
237	889	Maintenance Meas and Reg. General	LB889	F008		78,000	-	-	-	-	-	-
238	890	Maintenance Meas and Reg - Industrial	LB890	F011		188,595	-	-	-	-	-	-
239	891	Maintenance Meas and Reg.-City Gate	LB891	F008		411,320	-	-	-	-	-	-
240	892	Maintenance Services	LB892	F010		537,961	-	-	-	-	-	-
241	893	Maintenance Meters and House Reg.	LB893	F011		-	-	-	-	-	-	-
242	894	Maintenance Other Equipment	LB894	PTDSUB		86,000	-	-	-	-	-	-
243												
244	Total Maintenance Labor		LBDM		$	5,246,820	$ -	$ -	$ -	$ -	$ -	$ -
245												
246	Total Transmission & Distribution Labor		LBTD		$	16,133,567	$ -	$ -	$ -	$ -	$ 2,439,169	$ 479,967
247												
248												
249	Customer Accounts Expense											
250	901	Supervision	LB901	F012	$	858,916	-	-	-	-	-	-
251	902	Meter Reading	LB902	F012		291,309	-	-	-	-	-	-
252	903	Customer Records and Collections	LB903	F012		2,764,532	-	-	-	-	-	-
253	904	Uncollectible Accounts	LB904	F012		-	-	-	-	-	-	-
254	905	Misc. Cust Account Expenses	LB905	F012		-	-	-	-	-	-	-
255												
256	Total Customer Accounts Labor		LBCA		$	3,914,757	$ -	$ -	$ -	$ -	$ -	$ -
257												
258	Customer Service Expenses											
259	907-910	Customer Service	LB907	F013	$	240,990	-	-	-	-	-	-
260												
261	Sales Expenses											
262	911-916	Sales Expenses	LB911	F013	$	-	-	-	-	-	-	-
263												
264												
265												
266												
267												
268												
269												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1					Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	Description		Name	Vector	Commodity	Demand	Demand	Customer	Demand	Customer
3										
227										
228	**Labor Expenses (Continued)**									
229										
230										
231	**Maintenance Expense -- Distribution**									
232										
233	885	Maintenance Supr and Engr	LB885	DMES	-	-	-	-	-	-
234	886	Maintenance Structures	LB886	F008	-	-	-	-	-	-
235	887	Maintenance Mains	LB887	F009	-	-	1,118,982	2,456,415	194,255	175,292
236	888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-
237	889	Maintenance Meas and Reg. General	LB889	F008	-	78,000	-	-	-	-
238	890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-
239	891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	411,320	-	-	-	-
240	892	Maintenance Services	LB892	F010	-	-	-	-	-	-
241	893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-	-	-
242	894	Maintenance Other Equipment	LB894	PTDSUB	-	5,125	11,106	24,380	1,928	1,740
243										
244	Total Maintenance Labor		LBDM		$ -	$ 494,445	$ 1,130,088	$ 2,480,795	$ 196,183	$ 177,032
245										
246	Total Transmission & Distribution Labor		LBTD		$ 838,265	$ 1,678,232	$ 1,760,023	$ 3,863,645	$ 305,540	$ 275,713
247										
248										
249	**Customer Accounts Expense**									
250	901	Supervision	LB901	F012	-	-	-	-	-	-
251	902	Meter Reading	LB902	F012	-	-	-	-	-	-
252	903	Customer Records and Collections	LB903	F012	-	-	-	-	-	-
253	904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-
254	905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-
255										
256	Total Customer Accounts Labor		LBCA		$ -	$ -	$ -	$ -	$ -	$ -
257										
258	**Customer Service Expenses**									
259	907-910	Customer Service	LB907	F013	-	-	-	-	-	-
260										
261	**Sales Expenses**									
262	911-916	Sales Expenses	LB911	F013	-	-	-	-	-	-
263										
264										
265										
266										
267										
268										
269										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
227								
228	Labor Expenses (Continued)							
229								
230								
231	Maintenance Expense -- Distribution							
232								
233	885	Maintenance Supr and Engr	LB885	DMES	-	-	-	-
234	886	Maintenance Structures	LB886	F008	-	-	-	-
235	887	Maintenance Mains	LB887	F009	-	-	-	-
236	888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-
237	889	Maintenance Meas and Reg. General	LB889	F008	-	-	-	-
238	890	Maintenance Meas and Reg - Industrial	LB890	F011	-	188,595	-	-
239	891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-
240	892	Maintenance Services	LB892	F010	537,961	-	-	-
241	893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-
242	894	Maintenance Other Equipment	LB894	PTDSUB	33,661	8,060	-	-
243								
244	Total Maintenance Labor		LBDM		$ 571,622	$ 196,655	$ -	$ -
245								
246	Total Transmission & Distribution Labor		LBTD		$ 2,480,889	$ 2,012,124	$ -	$ -
247								
248								
249	Customer Accounts Expense							
250	901	Supervision	LB901	F012	-	-	858,916	-
251	902	Meter Reading	LB902	F012	-	-	291,309	-
252	903	Customer Records and Collections	LB903	F012	-	-	2,764,532	-
253	904	Uncollectible Accounts	LB904	F012	-	-	-	-
254	905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-
255								
256	Total Customer Accounts Labor		LBCA		$ -	$ -	$ 3,914,757	$ -
257								
258	Customer Service Expenses							
259	907-910	Customer Service	LB907	F013	-	-	-	240,990
260								
261	Sales Expenses							
262	911-916	Sales Expenses	LB911	F013	-	-	-	-
263								
264								
265								
266								
267								
268								
269								

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	**Description**		**Name**	**Vector**		**Company**	**Demand**	**Commodity**	**Demand**	**Commodity**	**Demand**	**Demand**
3												
270												
271	**Labor Expenses (Continued)**											
272												
273												
274	**Administrative & General**											
275	920	Admin and General Salaries	LB920	LBSUB		$6,639,407	21,993	165,339	343,631	734,813	646,015	127,119
276	921	Office Supplies and Expense	LB921	LBSUB		-	-	-	-	-	-	-
277	922	Admin. Expenses Transferred	LB922	LBSUB		(774,439)	(2,565)	(19,286)	(40,082)	(85,711)	(75,353)	(14,828)
278	923	Outside Services Employed	LB923	LBSUB		-	-	-	-	-	-	-
279	924	Property Insurance	LB924	PTT		-	-	-	-	-	-	-
280	925	Injuries and Damages	LB925	LBSUB		-	-	-	-	-	-	-
281	926	Employee Pensions and Benefits	LB926	LBSUB		-	-	-	-	-	-	-
282	927	Franchise Requirement	LB927	PTT		-	-	-	-	-	-	-
283	928	Regulatory Commission Fee	LB928	PTT		-	-	-	-	-	-	-
284	929	Duplicate Charges -Credit	LB929	LBSUB		-	-	-	-	-	-	-
285	930.1	General Advertising Expense	LB930.1	PTT		-	-	-	-	-	-	-
286	930.2	Misc. General Expense	LB930.2	LBSUB		-	-	-	-	-	-	-
287	931	Rents	LB931	PTT		-	-	-	-	-	-	-
288	935	Maintenance of General Plant	LB935	PT389		225,648	-	-	29,746	-	28,061	5,522
289												
290	Total Administrative and General Labor		LBAG			$ 6,090,616	$ 19,427	$ 146,053	$ 333,295	$ 649,103	$ 598,723	$ 117,814
291												
292	Total Labor Expense		LBTOT			$ 31,159,141	$ 102,466	$ 770,325	$ 1,630,747	$ 3,423,550	$ 3,037,891	$ 597,781
293												
294												
295												
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312												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1						Distribution Structures	Distribution Mains -	Distribution Mains -	Distribution Mains -	Distribution Mains -
					Distribution	& Equipment	Low & Med. Pressure	Low & Med. Pressure	High Pressure	High Pressure
2	Description		Name	Vector	Commodity	Demand	Demand	Customer	Demand	Customer
3										
270										
271	**Labor Expenses (Continued)**									
272										
273										
274	**Administrative & General**									
275	920	Admin and General Salaries	LB920	LBSUB	222,015	444,480	466,143	1,023,288	80,922	73,023
276	921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-
277	922	Admin. Expenses Transferred	LB922	LBSUB	(25,896)	(51,845)	(54,372)	(119,359)	(9,439)	(8,518)
278	923	Outside Services Employed	LB923	LBSUB	-	-	-	-	-	-
279	924	Property Insurance	LB924	PTT	-	-	-	-	-	-
280	925	Injuries and Damages	LB925	LBSUB	-	-	-	-	-	-
281	926	Employee Pensions and Benefits	LB926	LBSUB	-	-	-	-	-	-
282	927	Franchise Requirement	LB927	PTT	-	-	-	-	-	-
283	928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-
284	929	Duplicate Charges -Credit	LB929	LBSUB	-	-	-	-	-	-
285	930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-
286	930.2	Misc. General Expense	LB930.2	LBSUB	-	-	-	-	-	-
287	931	Rents	LB931	PTT	-	-	-	-	-	-
288	935	Maintenance of General Plant	LB935	PT389	-	9,673	20,962	46,016	3,639	3,284
289										
290	Total Administrative and General Labor		LBAG		$ 196,118	$ 402,308	$ 432,732	$ 949,944	$ 75,122	$ 67,789
291										
292	Total Labor Expense		LBTOT		$ 1,034,383	$ 2,080,540	$ 2,192,756	$ 4,813,589	$ 380,662	$ 343,502

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
270								
271	**Labor Expenses (Continued)**							
272								
273								
274	**Administrative & General**							
275	920	Admin and General Salaries	LB920	LBSUB	657,064	532,912	1,036,825	63,826
276	921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-
277	922	Admin. Expenses Transferred	LB922	LBSUB	(76,642)	(62,160)	(120,938)	(7,445)
278	923	Outside Services Employed	LB923	LBSUB	-	-	-	-
279	924	Property Insurance	LB924	PTT	-	-	-	-
280	925	Injuries and Damages	LB925	LBSUB	-	-	-	-
281	926	Employee Pensions and Benefits	LB926	LBSUB	-	-	-	-
282	927	Franchise Requirement	LB927	PTT	-	-	-	-
283	928	Regulatory Commission Fee	LB928	PTT	-	-	-	-
284	929	Duplicate Charges -Credit	LB929	LBSUB	-	-	-	-
285	930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-
286	930.2	Misc. General Expense	LB930.2	LBSUB	-	-	-	-
287	931	Rents	LB931	PTT	-	-	-	-
288	935	Maintenance of General Plant	LB935	PT389	63,533	15,213	-	-
289								
290	Total Administrative and General Labor		LBAG		$ 643,955	$ 485,964	$ 915,887	$ 56,381
291								
292	Total Labor Expense		LBTOT		$ 3,124,844	$ 2,498,089	$ 4,830,644	$ 297,372
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1											Transmission Non-	Transmission Storage
2	Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Storage Related Demand	Related Demand
3												
313												
314	**Operation & Maintenance Expenses**											
315												
316	807 & 810	Procurement Expenses	OM807	DMCM	$	992,354	116,502	875,852	-	-	-	-
317												
318	**Storage Expenses**											
319	**Operation**											
320	814	Operations Supervision and Engineer	OM814	OSE		1,152,053	-	-	191,367	960,686	-	-
321	815	Maps and Records	OM815	F003		-	-	-	-	-	-	-
322	816	Well Expenses	OM816	F003		67,379	-	-	67,379	-	-	-
323	817	Lines Expenses	OM817	F003		456,556	-	-	456,556	-	-	-
324	818	Compressor Station Exp - Payroll	OM818	F004		2,565,926	-	-	-	2,565,926	-	-
325	819	Compressor Station Fuel and Power	OM819	F004		85,300	-	-	-	85,300	-	-
326	820	Measurement and Regulator Station	OM820	F003		-	-	-	-	-	-	-
327	821	Purification of Natural Gas *(1)*	OM821	F004		1,378,252	-	-	-	1,378,252	-	-
328	823	Gas losses *(2)*	OM823	F004		-	-	-	-	-	-	-
329	824	Other Expenses	OM824	F004		-	-	-	-	-	-	-
330	825	Storage Well Royalities	OM825	F003		159,348	-	-	159,348	-	-	-
331	826	Rents	OM826	F003		-	-	-	-	-	-	-
332												
333	Total Operation Expenses		OMOE		$	5,864,814	$ -	$ -	$ 874,650	$ 4,990,164	$ -	$ -
334												
335												
336												
337	**Storage Expense**											
338	**Maintenance**											
339	830	Maintenance Super and Eng.	OM830	MSE	$	634,879	-	-	341,979	292,900	-	-
340	831	Maintenance of Structures	OM831	F003		-	-	-	-	-	-	-
341	832	Maintenance of Resevoirs	OM832	F003		912,108	-	-	912,108	-	-	-
342	833	Maintenance of Lines	OM833	F003		915,216	-	-	915,216	-	-	-
343	834	Main of Compressor Station Equipment	OM834	F004		728,517	-	-	-	728,517	-	-
344	835	Main of Meas and Reg Sta. Equip	OM835	F003		-	-	-	-	-	-	-
345	836	Main of Purification Equip	OM836	F004		872,407	-	-	-	872,407	-	-
346	837	Main of Other Equipment	OM837	F003		340,227	-	-	340,227	-	-	-
347												
348	Total Maintenance Expense		OMME		$	4,403,354	$ -	$ -	$ 2,509,530	$ 1,893,824	$ -	$ -
349												
350												
351	Total Storage Expense		OMS		$	10,268,168	-	-	3,384,180	6,883,988	-	-
352												
353												
354												
355												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1					Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	**Description**		**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3										
313										
314	**Operation & Maintenance Expenses**									
315										
316	807 & 810	Procurement Expenses	OM807	DMCM	-	-	-	-	-	-
317										
318	**Storage Expenses**									
319	**Operation**									
320	814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-
321	815	Maps and Records	OM815	F003	-	-	-	-	-	-
322	816	Well Expenses	OM816	F003	-	-	-	-	-	-
323	817	Lines Expenses	OM817	F003	-	-	-	-	-	-
324	818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-
325	819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-
326	820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-
327	821	Purification of Natural Gas *(1)*	OM821	F004	-	-	-	-	-	-
328	823	Gas losses *(2)*	OM823	F004	-	-	-	-	-	-
329	824	Other Expenses	OM824	F004	-	-	-	-	-	-
330	825	Storage Well Royalities	OM825	F003	-	-	-	-	-	-
331	826	Rents	OM826	F003	-	-	-	-	-	-
332										
333	Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -	$ -	$ -
334										
335										
336										
337	**Storage Expense**									
338	**Maintenance**									
339	830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-
340	831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-
341	832	Maintenance of Resevoirs	OM832	F003	-	-	-	-	-	-
342	833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-
343	834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-
344	835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-
345	836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-
346	837	Main of Other Equipment	OM837	F003	-	-	-	-	-	-
347										
348	Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -	$ -	$ -
349										
350										
351	Total Storage Expense		OMS		-	-	-	-	-	-
352										
353										
354										
355										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	**Description**		**Name**	**Vector**	**Customer**	**Customer**	**Customer**	**Customer**
3								
313								
314	**Operation & Maintenance Expenses**							
315								
316	807 & 810	Procurement Expenses	OM807	DMCM	-	-	-	-
317								
318	**Storage Expenses**							
319	**Operation**							
320	814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-
321	815	Maps and Records	OM815	F003	-	-	-	-
322	816	Well Expenses	OM816	F003	-	-	-	-
323	817	Lines Expenses	OM817	F003	-	-	-	-
324	818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-
325	819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-
326	820	Measurement and Regulator Station	OM820	F003	-	-	-	-
327	821	Purification of Natural Gas *(1)*	OM821	F004	-	-	-	-
328	823	Gas losses *(2)*	OM823	F004	-	-	-	-
329	824	Other Expenses	OM824	F004	-	-	-	-
330	825	Storage Well Royalities	OM825	F003	-	-	-	-
331	826	Rents	OM826	F003	-	-	-	-
332								
333	Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -
334								
335								
336								
337	**Storage Expense**							
338	**Maintenance**							
339	830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-
340	831	Maintenance of Structures	OM831	F003	-	-	-	-
341	832	Maintenance of Resevoirs	OM832	F003	-	-	-	-
342	833	Maintenance of Lines	OM833	F003	-	-	-	-
343	834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-
344	835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-
345	836	Main of Purification Equip	OM836	F004	-	-	-	-
346	837	Main of Other Equipment	OM837	F003	-	-	-	-
347								
348	Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -
349								
350								
351	Total Storage Expense		OMS		-	-	-	-
352								
353								
354								
355								

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1											Transmission Non-	Transmission Storage
2	Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Storage Related Demand	Related Demand
3												
356												
357	**Operation & Maintenance Expenses (Continued)**											
358												
359												
360	**Transmission**											
361	850-867	Transmission Expenses	OM850	F005	$	18,074,099	-	-	-	-	15,102,338	2,971,761
362												
363	**Distribution Expenses**											
364	**Operation**											
365	870	Operation Supr and Engr	OM870	DOES	$	-	-	-	-	-	-	-
366	871	Dist Load Dispatching	OM871	F007		1,075,433	-	-	-	-	-	-
367	872	Compr. Station Labor and Exp.	OM872	F007		-	-	-	-	-	-	-
368	873	Compr. Station Fuel and Power	OM873	F007		-	-	-	-	-	-	-
369	874.01	Other Mains/Serv. Expenses	OM874.01	CADAL		9,885,996	-	-	-	-	-	-
370	874.02	Leak Survey-Mains	OM874.02	F009		-	-	-	-	-	-	-
371	874.03	Leak Survey - Service	OM874.03	F010		-	-	-	-	-	-	-
372	874.04	Locate Main per Request	OM874.04	CADAL		-	-	-	-	-	-	-
373	874.05	Check Stop Box Access	OM874.05	F010		-	-	-	-	-	-	-
374	874.06	Patrolling Mains	OM874.06	F009		-	-	-	-	-	-	-
375	874.07	Check/Grease Valves	OM874.07	F009		-	-	-	-	-	-	-
376	874.08	Opr. Odor Equipment	OM874.08	F007		-	-	-	-	-	-	-
377	874.09	Locate and Inspect Valve Boxes	OM874.09	F009		-	-	-	-	-	-	-
378	874.1	Cut Grass - Right of Way	OM874.10	F009		-	-	-	-	-	-	-
379	875	Meas and Reg Station Exp.- General	OM875	F008		1,439,892	-	-	-	-	-	-
380	876	Meas and Reg Station Exp.- Industrial	OM876	F011		649,731	-	-	-	-	-	-
381	877	Meas and Reg Station Exp. - City Gate	OM877	F008		269,704	-	-	-	-	-	-
382	878	Meter and House Reg. Expense	OM878	F011		2,254,644	-	-	-	-	-	-
383	879	Customer Installation Expense	OM879	F011		234,605	-	-	-	-	-	-
384	880	Other Expenses	OM880	PTDSUB		7,923,534	-	-	-	-	-	-
385	881	Rents	OM881	PTDSUB		26,536	-	-	-	-	-	-
386												
387	Total Operations Distribution Expense		OMDO		$	23,760,075	-	-	-	-	-	-
388												
389	Total Transmission and Distribution Oper Exp		OMTDO		$	41,834,174	$ -	$ -	$ -	$ -	$ 15,102,338	$ 2,971,761
390												
391												
392												
393												
394												
395												
396												
397												
398												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1						Distribution Structures	Distribution Mains -	Distribution Mains -	Distribution Mains -	Distribution Mains -
					Distribution	& Equipment	Low & Med. Pressure	Low & Med. Pressure	High Pressure	High Pressure
2	Description		Name	Vector	Commodity	Demand	Demand	Customer	Demand	Customer
3										
356										
357	**Operation & Maintenance Expenses (Continued)**									
358										
359										
360	**Transmission**									
361	850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-
362										
363	**Distribution Expenses**									
364	**Operation**									
365	870	Operation Supr and Engr	OM870	DOES	-	-	-	-	-	-
366	871	Dist Load Dispatching	OM871	F007	1,075,433	-	-	-	-	-
367	872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-
368	873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-
369	874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	1,507,846	3,310,059	261,762	236,209
370	874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-
371	874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-
372	874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-
373	874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-
374	874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-
375	874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-
376	874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-
377	874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-
378	874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-
379	875	Meas and Reg Station Exp.- General	OM875	F008	-	1,439,892	-	-	-	-
380	876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-
381	877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	269,704	-	-	-	-
382	878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-
383	879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-
384	880	Other Expenses	OM880	PTDSUB	-	472,187	1,023,241	2,246,242	177,634	160,294
385	881	Rents	OM881	PTDSUB	-	1,581	3,427	7,523	595	537
386										
387	Total Operations Distribution Expense		OMDO		1,075,433	2,183,364	2,534,514	5,563,824	439,991	397,039
388										
389	Total Transmission and Distribution Oper Exp		OMTDO		$ 1,075,433	$ 2,183,364	$ 2,534,514	$ 5,563,824	$ 439,991	$ 397,039
390										
391										
392										
393										
394										
395										
396										
397										
398										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	**Description**		**Name**	**Vector**	**Customer**	**Customer**	**Customer**	**Customer**
3								
356								
357	**Operation & Maintenance Expenses (Continued)**							
358								
359								
360	**Transmission**							
361	850-867	Transmission Expenses	OM850	F005	-	-	-	-
362								
363	**Distribution Expenses**							
364	**Operation**							
365	870	Operation Supr and Engr	OM870	DOES	-	-	-	-
366	871	Dist Load Dispatching	OM871	F007	-	-	-	-
367	872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-
368	873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-
369	874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	4,570,120	-	-	-
370	874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-
371	874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-
372	874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-
373	874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-
374	874.06	Patrolling Mains	OM874.06	F009	-	-	-	-
375	874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-
376	874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-
377	874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-
378	874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-
379	875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-
380	876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	649,731	-	-
381	877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-
382	878	Meter and House Reg. Expense	OM878	F011	-	2,254,644	-	-
383	879	Customer Installation Expense	OM879	F011	-	234,605	-	-
384	880	Other Expenses	OM880	PTDSUB	3,101,333	742,603	-	-
385	881	Rents	OM881	PTDSUB	10,386	2,487	-	-
386								
387	Total Operations Distribution Expense		OMDO		7,681,839	3,884,070	-	-
388								
389	Total Transmission and Distribution Oper Exp		OMTDO		$ 7,681,839	$ 3,884,070	$ -	$ -
390								
391								
392								
393								
394								
395								
396								
397								
398								

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1											Transmission Non-	Transmission Storage
2	Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Storage Related Demand	Related Demand
3												
399												
400	**Operation & Maintenance Expenses (Continued)**											
401												
402												
403	**Maintenance Expense -- Distribution**											
404												
405	885	Maintenance Supr and Engr	OM885	DMES		-	-	-	-	-	-	-
406	886	Maintenance Structures	OM886	F008		-	-	-	-	-	-	-
407	887	Maintenance Mains	OM887	F009		12,032,879	-	-	-	-	-	-
408	888	Maintenance Comp. Station Equip.	OM888	F007		-	-	-	-	-	-	-
409	889	Maintenance Meas and Reg. General	OM889	F008		175,037	-	-	-	-	-	-
410	890	Maintenance Meas and Reg - Industrial	OM890	F011		305,563	-	-	-	-	-	-
411	891	Maintenance Meas and Reg.-City Gate	OM891	F008		916,558	-	-	-	-	-	-
412	892	Maintenance Services	OM892	F010		874,567	-	-	-	-	-	-
413	893	Maintenance Meters and House Reg.	OM893	F011		-	-	-	-	-	-	-
414	894	Maintenance Other Equipment	OM894	PTDSUB		560,259	-	-	-	-	-	-
415												
416	Total Maintenance Expenses		OMME			$ 14,864,863	$ -	$ -	$ -	$ -	$ -	$ -
417												
418	Total Transmission & Distribution Expenses		OMDE			$ 56,699,037	$ -	$ -	$ -	$ -	$ 15,102,338	$ 2,971,761
419												
420												
421	**Customer Accounts Expense**											
422	901	Supervision	OM901	F012		1,177,715	-	-	-	-	-	-
423	902	Meter Reading	OM902	F012		3,001,871	-	-	-	-	-	-
424	903	Customer Records and Collections	OM903	F012		6,230,561	-	-	-	-	-	-
425	904	Uncollectible Accounts	OM904	F012		471,666	-	-	-	-	-	-
426	905	Misc. Cust Account Expenses	OM905	F012		-	-	-	-	-	-	-
427												
428	Total Customer Accounts Expense		OMCA			$ 10,881,813	$ -	$ -	$ -	$ -	$ -	$ -
429												
430	**Customer Service Expenses**											
431	907-910	Customer Service	OM907	F013		$ 1,302,017	-	-	-	-	-	-
432												
433	**Sales Expenses**											
434	911-916	Sales Expenses	OM911	F013		$ 15,840	-	-	-	-	-	-
435												
436												
437												
438												
439												
440												
441												

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1					Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	**Description**		**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3										
399										
400	**Operation & Maintenance Expenses (Continued)**									
401										
402										
403	**Maintenance Expense -- Distribution**									
404										
405	885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-	-	-
406	886	Maintenance Structures	OM886	F008	-	-	-	-	-	-
407	887	Maintenance Mains	OM887	F009	-	-	3,413,121	7,492,565	592,517	534,676
408	888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-
409	889	Maintenance Meas and Reg. General	OM889	F008	-	175,037	-	-	-	-
410	890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-
411	891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	916,558	-	-	-	-
412	892	Maintenance Services	OM892	F010	-	-	-	-	-	-
413	893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	-	-	-
414	894	Maintenance Other Equipment	OM894	PTDSUB	-	33,388	72,352	158,828	12,560	11,334
415										
416	Total Maintenance Expenses		OMME		$ -	$ 1,124,983	$ 3,485,473	$ 7,651,393	$ 605,077	$ 546,010
417										
418	Total Transmission & Distribution Expenses		OMDE		$ 1,075,433	$ 3,308,347	$ 6,019,987	$ 13,215,217	$ 1,045,068	$ 943,049
419										
420										
421	**Customer Accounts Expense**									
422	901	Supervision	OM901	F012	-	-	-	-	-	-
423	902	Meter Reading	OM902	F012	-	-	-	-	-	-
424	903	Customer Records and Collections	OM903	F012	-	-	-	-	-	-
425	904	Uncollectible Accounts	OM904	F012	-	-	-	-	-	-
426	905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-
427										
428	Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ -	$ -
429										
430	**Customer Service Expenses**									
431	907-910	Customer Service	OM907	F013	-	-	-	-	-	-
432										
433	**Sales Expenses**									
434	911-916	Sales Expenses	OM911	F013	-	-	-	-	-	-
435										
436										
437										
438										
439										
440										
441										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
400	**Operation & Maintenance Expenses (Continued)**							
403	**Maintenance Expense -- Distribution**							
405	885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-
406	886	Maintenance Structures	OM886	F008	-	-	-	-
407	887	Maintenance Mains	OM887	F009	-	-	-	-
408	888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-
409	889	Maintenance Meas and Reg. General	OM889	F008	-	-	-	-
410	890	Maintenance Meas and Reg - Industrial	OM890	F011	-	305,563	-	-
411	891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-
412	892	Maintenance Services	OM892	F010	874,567	-	-	-
413	893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	-
414	894	Maintenance Other Equipment	OM894	PTDSUB	219,290	52,508	-	-
416	Total Maintenance Expenses		OMME		$ 1,093,857	$ 358,071	$ -	$ -
418	Total Transmission & Distribution Expenses		OMDE		$ 8,775,696	$ 4,242,141	$ -	$ -
421	**Customer Accounts Expense**							
422	901	Supervision	OM901	F012	-	-	1,177,715	-
423	902	Meter Reading	OM902	F012	-	-	3,001,871	-
424	903	Customer Records and Collections	OM903	F012	-	-	6,230,561	-
425	904	Uncollectible Accounts	OM904	F012	-	-	471,666	-
426	905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-
428	Total Customer Accounts Expense		OMCA		$ -	$ -	$ 10,881,813	$ -
430	**Customer Service Expenses**							
431	907-910	Customer Service	OM907	F013	-	-	-	1,302,017
433	**Sales Expenses**							
434	911-916	Sales Expenses	OM911	F013	-	-	-	15,840

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	Description		Name	Vector		Company	Demand	Commodity	Demand	Commodity	Demand	Demand
3												
442												
443	**Operation & Maintenance Expenses (Continued)**											
444												
445												
446	**Administrative & General**											
447	920	Admin and General Salaries	OM920	LBSUB	$	8,591,131	28,458	213,942	444,645	950,819	835,917	164,488
448	921	Office Supplies and Expense	OM921	LBSUB		2,524,197	8,361	62,859	130,643	279,364	245,605	48,329
449	922	Admin. Expenses Transferred	OM922	LBSUB		(1,333,161)	(4,416)	(33,199)	(68,999)	(147,547)	(129,717)	(25,525)
450	923	Outside Services Employed	OM923	LBSUB		5,688,674	18,843	141,663	294,424	629,591	553,508	108,917
451	924	Property Insurance	OM924	PTT		469,694	-	-	64,620	-	61,469	12,096
452	925	Injuries and Damages	OM925	LBSUB		1,151,571	3,815	28,677	59,601	127,450	112,048	22,048
453	926	Employee Pensions and Benefits	OM926	LBSUB		9,373,328	31,049	233,420	485,128	1,037,389	912,025	179,464
454	927	Franchise Requirement	OM927	PTT		-	-	-	-	-	-	-
455	928	Regulatory Commission Fee	OM928	PTT		51,213	-	-	7,046	-	6,702	1,319
456	929	Duplicate Charges -Credit	OM929	LBSUB		(249,859)	(828)	(6,222)	(12,932)	(27,653)	(24,311)	(4,784)
457	930.1	General Advertising Expense	OM930.1	PTT		-	-	-	-	-	-	-
458	930.2	Misc. General Expense	OM930.2	LBSUB		391,917	1,298	9,760	20,284	43,375	38,134	7,504
459	931	Rents	OM931	PTT		602,647	-	-	82,911	-	78,868	15,519
460	935	Maintenance of General Plant	OM935	PT389		474,102	-	-	62,499	-	58,958	11,601
461												
462	Total Administrative and General Expense		OMAGT		$	27,735,455	$ 86,580	$ 650,900	$ 1,569,869	$ 2,892,789	$ 2,749,207	$ 540,975
463												
464	Total Operation & Maintenance Expense		OMT		$	107,894,684	$ 203,082	$ 1,526,751	$ 4,954,049	$ 9,776,777	$ 17,851,545	$ 3,512,736
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1					Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	Description		Name	Vector	Commodity	Demand	Demand	Customer	Demand	Customer
3										
442										
443	**Operation & Maintenance Expenses (Continued)**									
444										
445										
446	**Administrative & General**									
447	920	Admin and General Salaries	OM920	LBSUB	287,278	575,140	603,170	1,324,094	104,710	94,488
448	921	Office Supplies and Expense	OM921	LBSUB	84,406	168,984	177,220	389,038	30,765	27,762
449	922	Admin. Expenses Transferred	OM922	LBSUB	(44,579)	(89,250)	(93,599)	(205,471)	(16,249)	(14,663)
450	923	Outside Services Employed	OM923	LBSUB	190,223	380,833	399,393	876,757	69,335	62,566
451	924	Property Insurance	OM924	PTT	-	19,459	43,581	95,670	7,566	6,827
452	925	Injuries and Damages	OM925	LBSUB	38,507	77,093	80,850	177,484	14,036	12,665
453	926	Employee Pensions and Benefits	OM926	LBSUB	313,434	627,505	658,087	1,444,649	114,244	103,091
454	927	Franchise Requirement	OM927	PTT	-	-	-	-	-	-
455	928	Regulatory Commission Fee	OM928	PTT	-	2,122	4,752	10,431	825	744
456	929	Duplicate Charges -Credit	OM929	LBSUB	(8,355)	(16,727)	(17,542)	(38,509)	(3,045)	(2,748)
457	930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-
458	930.2	Misc. General Expense	OM930.2	LBSUB	13,105	26,237	27,516	60,404	4,777	4,310
459	931	Rents	OM931	PTT	-	24,967	55,917	122,750	9,707	8,760
460	935	Maintenance of General Plant	OM935	PT389	-	20,324	44,042	96,682	7,646	6,899
461										
462	Total Administrative and General Expense		OMAGT		$ 874,020	$ 1,816,687	$ 1,983,387	$ 4,353,978	$ 344,316	$ 310,703
463										
464	Total Operation & Maintenance Expense		OMT		$ 1,949,453	$ 5,125,034	$ 8,003,374	$ 17,569,195	$ 1,389,384	$ 1,253,752
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	**Description**		**Name**	**Vector**	**Customer**	**Customer**	**Customer**	**Customer**
3								
442								
443	**Operation & Maintenance Expenses (Continued)**							
444								
445								
446	**Administrative & General**							
447	920	Admin and General Salaries	OM920	LBSUB	850,215	689,567	1,341,610	82,589
448	921	Office Supplies and Expense	OM921	LBSUB	249,805	202,605	394,184	24,266
449	922	Admin. Expenses Transferred	OM922	LBSUB	(131,935)	(107,006)	(208,189)	(12,816)
450	923	Outside Services Employed	OM923	LBSUB	562,976	456,601	888,356	54,687
451	924	Property Insurance	OM924	PTT	127,806	30,603	-	-
452	925	Injuries and Damages	OM925	LBSUB	113,964	92,431	179,832	11,070
453	926	Employee Pensions and Benefits	OM926	LBSUB	927,625	752,350	1,463,760	90,108
454	927	Franchise Requirement	OM927	PTT	-	-	-	-
455	928	Regulatory Commission Fee	OM928	PTT	13,935	3,337	-	-
456	929	Duplicate Charges -Credit	OM929	LBSUB	(24,727)	(20,055)	(39,019)	(2,402)
457	930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-
458	930.2	Misc. General Expense	OM930.2	LBSUB	38,786	31,457	61,203	3,768
459	931	Rents	OM931	PTT	163,983	39,265	-	-
460	935	Maintenance of General Plant	OM935	PT389	133,487	31,963	-	-
461								
462	Total Administrative and General Expense		OMAGT		$ 3,025,920	$ 2,203,117	$ 4,081,738	$ 251,269
463								
464	Total Operation & Maintenance Expense		OMT		$ 11,801,616	$ 6,445,258	$ 14,963,550	$ 1,569,126
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466						$ 53,537,067		
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Depreciation Expenses											
Underground Storage											
350-357	Underground Storage Plant	DP350	F003	$	4,721,312	-	-	4,721,312	-	-	-
358	Asset Retire Obligation Gas Plant	DP350	F003	$	-	-	-	-	-	-	-
Total Underground Storage				$	4,721,312	-	-	4,721,312	-	-	-
Transmission											
365-372	Transmission Plant	DP365	F005	$	4,587,139	-	-	-	-	3,832,917	754,222
Distribution											
374	Land & Land Rights	DP374	F008	$	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008		40,931	-	-	-	-	-	-
376	Mains	DP376	F009		7,967,684	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008		947,875	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008		345,460	-	-	-	-	-	-
380	Services	DP380	F010		13,695,647	-	-	-	-	-	-
381	Meters	DP381	F011		2,659,640	-	-	-	-	-	-
382	Meter Installations	DP382	F011		-	-	-	-	-	-	-
383	House Regulators	DP383	F011		1,041,174	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011		-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011		49,860	-	-	-	-	-	-
387	Other Equipment	DP387	F011		38,227	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008		-	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009		-	-	-	-	-	-	-
Total Distribution				$	26,786,499	$ -	$ -	$ -	$ -	$ -	$ -
117	Gas Stored Underground	DP117	F003	$	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB		48	-	-	6	-	6	1
389-399	General Plant	DP389	PTSUB		470,124	-	-	61,974	-	58,463	11,504
Common Utility Plant		DPCP	PTSUB		10,749,764	-	-	1,417,089	-	1,336,814	263,051
Common Utility Plant Amortization		DPCP	PTSUB		-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$	47,314,886	$ -	$ -	$ 6,200,382	$ -	$ 5,228,200	$ 1,028,779
				$	36,565,122						
Regulatory Credits and Accretion											
	Regulatory Credits	REGCR	PTSUB	$	-	-	-	-	-	-	-
	Accretion	ACCRE	PTSUB	$	-	-	-	-	-	-	-
Amortization of Investment Tax Credits		ITCAM	PTSUB	$	(584)	-	-	(77)	-	(73)	(14)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1					Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	**Description**		**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3										
485										
486	**Depreciation Expenses**									
487										
488										
489	**Underground Storage**									
490	350-357	Underground Storage Plant	DP350	F003	-	-	-	-	-	-
491	358	Asset Retire Obligation Gas Plant	DP350	F003	-	-	-	-	-	-
492										
493	Total Underground Storage				-	-	-	-	-	-
494										
495	**Transmission**									
496	365-372	Transmission Plant	DP365	F005	-	-	-	-	-	-
497										
498	**Distribution**									
499	374	Land & Land Rights	DP374	F008	-	-	-	-	-	-
500	375	Structures & Improvements	DP375	F008	-	40,931	-	-	-	-
501	376	Mains	DP376	F009	-	-	2,260,031	4,961,273	392,341	354,040
502	378	Meas & Reg Station Eq.-Gen	DP378	F008	-	947,875	-	-	-	-
503	379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	345,460	-	-	-	-
504	380	Services	DP380	F010	-	-	-	-	-	-
505	381	Meters	DP381	F011	-	-	-	-	-	-
506	382	Meter Installations	DP382	F011	-	-	-	-	-	-
507	383	House Regulators	DP383	F011	-	-	-	-	-	-
508	384	House Regulator Installations	DP384	F011	-	-	-	-	-	-
509	385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	-	-	-
510	387	Other Equipment	DP387	F011	-	-	-	-	-	-
511	388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008	-	-	-	-	-	-
512	388	Asset Retire Obligation Gas Plant-Mains	DP388	F009	-	-	-	-	-	-
513										
514	Total Distribution				$ -	$ 1,334,265	$ 2,260,031	$ 4,961,273	$ 392,341	$ 354,040
515										
516	117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-
517	301-303	Intangible Plant	DP301	PTSUB	-	2	4	10	1	1
518	389-399	General Plant	DP389	PTSUB	-	20,153	43,673	95,871	7,582	6,841
519	Common Utility Plant		DPCP	PTSUB	-	460,821	998,611	2,192,174	173,359	156,435
520	Common Utility Plant Amortization		DPCP	PTSUB	-	-	-	-	-	-
521										
522	Total Depreciation Expense		DEPREX		$ -	$ 1,815,242	$ 3,302,319	$ 7,249,328	$ 573,282	$ 517,318
523										
524										
525	**Regulatory Credits and Accretion**									
526										
527		Regulatory Credits	REGCR	PTSUB	-	-	-	-	-	-
528										
529		Accretion	ACCRE	PTSUB	-	-	-	-	-	-
530										
531	**Amortization of Investment Tax Credits**		ITCAM	PTSUB	-	(25)	(54)	(119)	(9)	(8)
532										
533										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
485								
486	**Depreciation Expenses**							
487								
488								
489	**Underground Storage**							
490	350-357	Underground Storage Plant	DP350	F003	-	-	-	-
491	358	Asset Retire Obligation Gas Plant	DP350	F003	-	-	-	-
492								
493	Total Underground Storage				-	-	-	-
494								
495	**Transmission**							
496	365-372	Transmission Plant	DP365	F005	-	-	-	-
497								
498	**Distribution**							
499	374	Land & Land Rights	DP374	F008	-	-	-	-
500	375	Structures & Improvements	DP375	F008	-	-	-	-
501	376	Mains	DP376	F009	-	-	-	-
502	378	Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-
503	379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-
504	380	Services	DP380	F010	13,695,647	-	-	-
505	381	Meters	DP381	F011	-	2,659,640	-	-
506	382	Meter Installations	DP382	F011	-	-	-	-
507	383	House Regulators	DP383	F011	-	1,041,174	-	-
508	384	House Regulator Installations	DP384	F011	-	-	-	-
509	385	Industrial Meas & Reg Equipment	DP385	F011	-	49,860	-	-
510	387	Other Equipment	DP387	F011	-	38,227	-	-
511	388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008	-	-	-	-
512	388	Asset Retire Obligation Gas Plant-Mains	DP388	F009	-	-	-	-
513								
514	Total Distribution				$ 13,695,647	$ 3,788,902	$ -	$ -
515								
516	117	Gas Stored Underground	DP117	F003	-	-	-	-
517	301-303	Intangible Plant	DP301	PTSUB	14	3	-	-
518	389-399	General Plant	DP389	PTSUB	132,367	31,695	-	-
519	Common Utility Plant		DPCP	PTSUB	3,026,682	724,728	-	-
520	Common Utility Plant Amortization		DPCP	PTSUB	-	-	-	-
521								
522	Total Depreciation Expense		DEPREX		$ 16,854,710	$ 4,545,328	$ -	$ -
523								
524								
525	**Regulatory Credits and Accretion**							
526								
527		Regulatory Credits	REGCR	PTSUB	-	-	-	-
528								
529		Accretion	ACCRE	PTSUB	-	-	-	-
530								
531	**Amortization of Investment Tax Credits**		ITCAM	PTSUB	(164)	(39)	-	-
532								
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A / B	C	D	E	F	G	H	I	J	K	L
1										Transmission Non-	Transmission Storage
2	**Description**	**Name**	**Vector**		**Total Company**	**Procurement Demand**	**Procurement Commodity**	**Storage Demand**	**Storage Commodity**	**Storage Related Demand**	**Related Demand**
3											
534											
535	**<u>Taxes Other Than Income Taxes</u>**										
536											
537		OTRE	PTT			-	-	-	-	-	-
538	Taxes Other Than Income Taxes	OTPP	PTT		14,465,203	-	-	1,990,090	-	1,893,063	372,507
539	Unemployment Insurance	OTUN	LBTOT		-	-	-	-	-	-	-
540	Federal Old Age & Survivor Insurance	OTFICA	LBTOT		-	-	-	-	-	-	-
541	Public Service Commission Fee	OTCF	PTT		-	-	-	-	-	-	-
542	Miscellaneous	OTMISC	PTT		-	-	-	-	-	-	-
543											
544	Total Taxes Other Than Income Taxes	OTT		$	14,465,203	$ -	$ -	$ 1,990,090	$ -	$ 1,893,063	$ 372,507
545											
546											
547	**Interest Expenses**	INT	PTT	$	17,694,326	-	-	2,434,346	-	2,315,659	455,664
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1					Distribution	Distribution Structures & Equipment	Distribution Mains - Low & Med. Pressure	Distribution Mains - Low & Med. Pressure	Distribution Mains - High Pressure	Distribution Mains - High Pressure
2	**Description**		**Name**	**Vector**	**Commodity**	**Demand**	**Demand**	**Customer**	**Demand**	**Customer**
3										
534										
535	**Taxes Other Than Income Taxes**									
536										
537			OTRE	PTT	-	-	-	-		
538	Taxes Other Than Income Taxes		OTPP	PTT	-	599,274	1,342,159	2,946,340	232,999	210,253
539	Unemployment Insurance		OTUN	LBTOT	-	-	-	-	-	-
540	Federal Old Age & Survivor Insurance		OTFICA	LBTOT	-	-	-	-	-	-
541	Public Service Commission Fee		OTCF	PTT	-	-	-	-	-	-
542	Miscellaneous		OTMISC	PTT	-	-	-	-	-	-
543										
544	Total Taxes Other Than Income Taxes		OTT		$ -	$ 599,274	$ 1,342,159	$ 2,946,340	$ 232,999	$ 210,253
545										
546										
547	**Interest Expenses**		INT	PTT	-	733,053	1,641,775	3,604,062	285,012	257,189
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	**Description**		**Name**	**Vector**	**Customer**	**Customer**	**Customer**	**Customer**
3								
534								
535	**Taxes Other Than Income Taxes**							
536								
537			OTRE	PTT	-	-	-	-
538	Taxes Other Than Income Taxes		OTPP	PTT	3,936,045	942,472	-	-
539	Unemployment Insurance		OTUN	LBTOT	-	-	-	-
540	Federal Old Age & Survivor Insurance		OTFICA	LBTOT	-	-	-	-
541	Public Service Commission Fee		OTCF	PTT	-	-	-	-
542	Miscellaneous		OTMISC	PTT	-	-	-	-
543								
544	Total Taxes Other Than Income Taxes		OTT		$ 3,936,045	$ 942,472	$ -	$ -
545								
546								
547	**Interest Expenses**		INT	PTT	4,814,704	1,152,864	-	-
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1											Transmission Non-	Transmission Storage
2	Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Storage Related Demand	Related Demand
3												
577												
578	**Functional Assignment Vectors**											
579												
580	Gas Supply Demand		F001			1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
581	Gas Supply Commodity		F002			1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
582	Storage Demand		F003			1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
583	Storage Commodity		F004			1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
584	Transmission Demand		F005			1.000000	0.000000	0.000000	0.000000	0.000000	0.835579	0.164421
585	Distribution Expense Commodity		F007			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
586	Distribution Structures & Equipment		F008			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
587	Distribution Mains		F009			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
588	Services		F010			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
589	Meters		F011			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
590	Customer Accounts		F012			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
591	Customer Service Expense		F013			1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
592												
593	Transmission & Distribution Mains		TDMSUB			$ 715,138,225	$ -	$ -	$ -	$ -	$ 186,703,851	$ 36,738,637
594												
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	M	N	O	P	Q	R
1						Distribution Structures	Distribution Mains -	Distribution Mains -	Distribution Mains -	Distribution Mains -
					Distribution	& Equipment	Low & Med. Pressure	Low & Med. Pressure	High Pressure	High Pressure
2	Description		Name	Vector	Commodity	Demand	Demand	Customer	Demand	Customer
3										
577										
578	**Functional Assignment Vectors**									
579										
580	Gas Supply Demand		F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
581	Gas Supply Commodity		F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
582	Storage Demand		F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
583	Storage Commodity		F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
584	Transmission Demand		F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
585	Distribution Expense Commodity		F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
586	Distribution Structures & Equipment		F008		0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
587	Distribution Mains		F009		0.000000	0.000000	0.283650	0.622674	0.049242	0.044435
588	Services		F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
589	Meters		F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
590	Customer Accounts		F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
591	Customer Service Expense		F013		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
592										
593	Transmission & Distribution Mains		TDMSUB		$ -	$ -	$ 139,469,306	$ 306,166,312	$ 24,211,839	$ 21,848,279
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
577								
578	**Functional Assignment Vectors**							
579								
580	Gas Supply Demand		F001		0.000000	0.000000	0.000000	0.000000
581	Gas Supply Commodity		F002		0.000000	0.000000	0.000000	0.000000
582	Storage Demand		F003		0.000000	0.000000	0.000000	0.000000
583	Storage Commodity		F004		0.000000	0.000000	0.000000	0.000000
584	Transmission Demand		F005		0.000000	0.000000	0.000000	0.000000
585	Distribution Expense Commodity		F007		0.000000	0.000000	0.000000	0.000000
586	Distribution Structures & Equipment		F008		0.000000	0.000000	0.000000	0.000000
587	Distribution Mains		F009		0.000000	0.000000	0.000000	0.000000
588	Services		F010		1.000000	0.000000	0.000000	0.000000
589	Meters		F011		0.000000	1.000000	0.000000	0.000000
590	Customer Accounts		F012		0.000000	0.000000	1.000000	0.000000
591	Customer Service Expense		F013		0.000000	0.000000	0.000000	1.000000
592								
593	Transmission & Distribution Mains		TDMSUB		$ -	$ -	$ -	$ -
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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	E	F	G	H	I	J	K	L
1						Total	Procurement	Procurement	Storage	Storage	Transmission Non-Storage Related	Transmission Storage Related
2	Description		Name	Vector		Company	Demand	Commodity	Demand	Commodity	Demand	Demand
3												
619												
620	**Internally Generated Functional Vectors**											
621												
622	Sub-Total Distribution Plant			PTDSUB		1.000000	-	-	-	-	-	-
623	Storage-Transmission-Distribution Subtotal			PTSUB		1.000000	-	-	0.131825	-	0.124357	0.024470
624	Total Storage Plant			PTST		1.000000	-	-	1.000000	-	-	-
625	Transmission Plant			PT365		1.000000	-	-	-	-	0.835579	0.164421
626	General Plant			PT389		1.000000	-	-	0.131825	-	0.124357	0.024470
627	Total Distribution Plant			PTDSUB		1.000000	-	-	-	-	-	-
628	Sub-Total CWIP			CWIP		1.000000	-	-	0.120857	-	0.373018	0.073401
629	Total Operation and Maintenance Expenses			OMT		1.000000	0.001882	0.014150	0.045916	0.090614	0.165453	0.032557
630	Total Depreciation Reserve			DEPR		1.000000	-	-	0.107905	-	0.043342	0.008529
631	Storage-Transmission -Distribution Plant Subtotal			PTSUB		1.000000	-	-	0.131825	-	0.124357	0.024470
632	Total Labor Expenses			LBTOT		1.000000	0.003288	0.024722	0.052336	0.109873	0.097496	0.019185
633	Transmission and Distribution Payroll			LBTD		1.000000	-	-	-	-	0.151186	0.029750
634	Transmission and Distribution Mains			TDMSUB		1.000000	-	-	-	-	0.261074	0.051373
635	Storage Operation Expenses Labor Subtotal		OSE			1,616,051	-	-	268,441	1,347,610	-	-
636	Storage Maintenance Expenses Labor Subtotal		MSE			1,230,058	-	-	662,574	567,484	-	-
637	Mains & Services		CADAL			914,412,247	-	-	-	-	-	-
638	Demand/Commodity Percent of Purchased Gas Cost		DMCM			1.00000	11.74%	88.26%				
639	Distribution Operation Expenses Labor Subtotal		DOES			7,967,611	-	-	-	-	-	-
640	Distribution Maintenance Expenses Labor Subtotal		DMES			5,246,820	-	-	-	-	-	-
641	Subtotal Labor Expenses		LBSUB		$	25,068,525	$ 83,038	$ 624,272	$ 1,297,453	$ 2,774,447	$ 2,439,169	$ 479,967
642	Subtotal O&M Expenses		OMSUB		$	80,159,229	$ 116,502	$ 875,852	$ 3,384,180	$ 6,883,988	$ 15,102,338	$ 2,971,761
643	Depreciation Reserve - Distribution		DEPRDIS		$	239,031,181	$ -	$ -	$ -	$ -	$ -	$ -

Exhibit WSS-36
Page 44 of 45

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A / B	C	D	M	N	O	P	Q	R
1 / 2	**Description**	**Name**	**Vector**	**Distribution Commodity**	**Distribution Structures & Equipment Demand**	**Distribution Mains - Low & Med. Pressure Demand**	**Distribution Mains - Low & Med. Pressure Customer**	**Distribution Mains - High Pressure Demand**	**Distribution Mains - High Pressure Customer**
3									
619									
620	**Internally Generated Functional Vectors**								
621									
622	Sub-Total Distribution Plant		PTDSUB	-	0.059593	0.129139	0.283490	0.022419	0.020230
623	Storage-Transmission-Distribution Subtotal		PTSUB	-	0.042868	0.092896	0.203928	0	0
624	Total Storage Plant		PTST	-	-	-	-	-	-
625	Transmission Plant		PT365	-	-	-	-	-	-
626	General Plant		PT389	-	0.042868	0.092896	0.203928	0	0
627	Total Distribution Plant		PTDSUB	-	0.059593	0.129139	0.283490	0	0
628	Sub-Total CWIP		CWIP	-	0.004501	0.111073	0.243829	0	0
629	Total Operation and Maintenance Expenses		OMT	0.018068	0.047500	0.074178	0.162837	0	0
630	Total Depreciation Reserve		DEPR	-	0.018257	0.146856	0.251182	0	0
631	Storage-Transmission -Distribution Plant Subtotal		PTSUB	-	0.042868	0.092896	0.203928	0	0
632	Total Labor Expenses		LBTOT	0.033197	0.066771	0.070373	0.154484	0	0
633	Transmission and Distribution Payroll		LBTD	0.051958	0.104021	0.109091	0.239479	0	0
634	Transmission and Distribution Mains		TDMSUB	-	-	0.195024	0.428122	0	0
635	Storage Operation Expenses Labor Subtotal	OSE		-	-	-	-	-	-
636	Storage Maintenance Expenses Labor Subtotal	MSE		-	-	-	-	-	-
637	Mains & Services	CADAL		-	-	139,469,306	306,166,312	24,211,839	21,848,279
638	Demand/Commodity Percent of Purchased Gas Cost	DMCM							
639	Distribution Operation Expenses Labor Subtotal	DOES		838,265	1,183,787	629,935	1,382,849	109,357	98,681
640	Distribution Maintenance Expenses Labor Subtotal	DMES		-	494,445	1,130,088	2,480,795	196,183	177,032
641	Subtotal Labor Expenses	LBSUB		$ 838,265	$ 1,678,232	$ 1,760,023	$ 3,863,645	$ 305,540	$ 275,713
642	Subtotal O&M Expenses	OMSUB		$ 1,075,433	$ 3,308,347	$ 6,019,987	$ 13,215,217	$ 1,045,068	$ 943,049
643	Depreciation Reserve - Distribution	DEPRDIS		$ -	$ 4,247,160	$ 42,919,420	$ 71,843,810	$ 6,245,561	$ 4,501,029

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Functional Assignment and Classification

	A	B	C	D	S	T	U	V
1					Services	Meters	Customer Accounts	Customer Service Expense
2	Description		Name	Vector	Customer	Customer	Customer	Customer
3								
619								
620	**Internally Generated Functional Vectors**							
621								
622	Sub-Total Distribution Plant			PTDSUB	0.391408	0.093721	-	-
623	Storage-Transmission-Distribution Subtotal			PTSUB	0	0	-	-
624	Total Storage Plant			PTST	-	-	-	-
625	Transmission Plant			PT365	-	-	-	-
626	General Plant			PT389	0	0	-	-
627	Total Distribution Plant			PTDSUB	0	0	-	-
628	Sub-Total CWIP			CWIP	0	0	-	-
629	Total Operation and Maintenance Expenses			OMT	0	0	0	0
630	Total Depreciation Reserve			DEPR	0	0	-	-
631	Storage-Transmission -Distribution Plant Subtotal			PTSUB	0	0	-	-
632	Total Labor Expenses			LBTOT	0	0	0	0
633	Transmission and Distribution Payroll			LBTD	0	0	-	-
634	Transmission and Distribution Mains			TDMSUB	-	-	-	-
635	Storage Operation Expenses Labor Subtotal		OSE		-	-	-	-
636	Storage Maintenance Expenses Labor Subtotal		MSE		-	-	-	-
637	Mains & Services		CADAL		422,716,510	-	-	-
638	Demand/Commodity Percent of Purchased Gas Cost		DMCM					
639	Distribution Operation Expenses Labor Subtotal		DOES		1,909,267	1,815,469	-	-
640	Distribution Maintenance Expenses Labor Subtotal		DMES		571,622	196,655	-	-
641	Subtotal Labor Expenses		LBSUB		$ 2,480,889	$ 2,012,124	$ 3,914,757	$ 240,990
642	Subtotal O&M Expenses		OMSUB		$ 8,775,696	$ 4,242,141	$ 10,881,813	$ 1,317,857
643	Depreciation Reserve - Distribution		DEPRDIS		$ 90,460,693	$ 18,813,509	$ -	$ -

Exhibit WSS-37

Gas Cost of Service Study
Class Allocation
(Louisville Gas and Electric Company)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
1											
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
5											
6	**Plant in Service**										
7											
8	**Procurement Expenses**										
9	Demand		PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
10	Commodity		PTIS	PTISGSC	COM01	-	-	-	-	-	-
11	Total Procurement Expenses					$ -	$ -	$ -	$ -	$ -	$ -
12											
13	**Storage**										
14	Demand		PTIS	PTISSD	DEM02	$ 225,613,142	$ 149,205,366	$ 69,309,707	$ 5,746,398	$ -	$ 1,351,670
15	Commodity		PTIS	PTISSC	COM02	-	-	-	-	-	-
16	Total Storage					$ 225,613,142	$ 149,205,366	$ 69,309,707	$ 5,746,398	$ -	$ 1,351,670
17											
18	**Transmission**										
19	Demand Non-Storage Related		PTIS	PTISTD	DEM04	$ 201,711,581	$ 107,174,739	$ 52,152,153	$ 4,032,119	$ 1,121,370	$ 37,231,200
20	Storage Related		PTIS	PTISTC	DEM03	39,691,782	26,249,477	12,193,553	1,010,955	-	237,797
21	Total Transmission					$ 241,403,364	$ 133,424,216	$ 64,345,706	$ 5,043,074	$ 1,121,370	$ 37,468,997
22											
23	**Distribution Expenses**										
24	Commodity		PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	**Distribution Structures & Equipment**										
27	Demand		PTIS	PTISDSD	DEM04	$ 69,533,228	$ 36,944,857	$ 17,977,686	$ 1,389,936	$ 386,554	$ 12,834,194
28											
29											
30	**Distribution Mains**										
31	Low/Medium Pressure - Demand		PTIS	PTISDMD	DEM05a	$ 150,680,204	$ 95,647,560	$ 46,416,572	$ 3,446,836	$ 973,226	$ 4,196,010
32	Low/Medium Pressure - Customer		PTIS	PTISDMC	CUSTPT01a	330,776,740	304,568,961	25,975,525	197,455	2,020	32,780
33	High Pressure - Demand		PTIS	PTISDMD	DEM05	26,158,049	13,898,468	6,763,115	522,887	145,420	4,828,159
34	High Pressure - Customer		PTIS	PTISDMC	CUSTPT01	23,604,500	21,730,642	1,853,396	14,448	216	5,797
35	Total Distribution Mains			PTISDIS		$ 531,219,492	$ 435,845,632	$ 81,008,607	$ 4,181,626	$ 1,120,882	$ 9,062,745
36											
37	**Services**										
38	Customer		PTIS	PTISSC	CUST02	$ 456,695,539	$ 355,142,191	$ 99,417,575	$ 1,508,115	$ 22,561	$ 605,097
39											
40	**Meters**										
41	Customer		PTIS	PTISMC	CUST03	$ 109,354,142	$ 67,501,026	$ 35,390,468	$ 2,510,382	$ 178,770	$ 3,773,497
42											
43	**Customer Accounts**										
44	Customer		PTIS	PTISCAC	CUSTPT04	$ -	$ -	$ -	$ -	$ -	$ -
45											
46	**Customer Service**										
47	Customer		PTIS	PTISCSC	CUSTPT05	$ -	$ -	$ -	$ -	$ -	$ -
48											
49	Total			PLT		$ 1,633,818,906	$ 1,178,063,287	$ 367,449,750	$ 20,379,532	$ 2,830,137	$ 65,096,200

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
50											
51											
52											
53											
54	**Rate Base**										
55											
56	**Procurement Expenses**										
57	Demand		NCRB	RBGSD	DEM01	$ 55,522	$ 36,178	$ 17,604	$ 1,361	$ 379	$ -
58	Commodity		NCRB	RBGSC	COM01	417,406	258,785	138,148	18,487	1,986	-
59	Total Procurement Expenses					$ 472,928	$ 294,962	$ 155,753	$ 19,849	$ 2,364	$ -
60											
61	**Storage**										
62	Demand		NCRB	RBSD	DEM02	$ 175,204,909	$ 115,868,749	$ 53,823,996	$ 4,462,494	$ -	$ 1,049,669
63	Commodity		NCRB	RBSC	COM02	2,672,923	1,711,821	881,288	79,814	-	-
64	Total Storage					$ 177,877,832	$ 117,580,570	$ 54,705,284	$ 4,542,308	$ -	$ 1,049,669
65											
66	**Transmission**										
67	Demand Non-Storage Related		NCRB	RBTD	DEM04	$ 177,537,247	$ 94,330,271	$ 45,901,924	$ 3,548,885	$ 986,979	$ 32,769,188
68	Storage Related		NCRB	RBTC	DEM03	34,934,880	23,103,581	10,732,204	889,796	-	209,298
69	Total Transmission					$ 212,472,126	$ 117,433,852	$ 56,634,128	$ 4,438,682	$ 986,979	$ 32,978,486
70											
71	**Distribution Expenses**										
72	Commodity		NCRB	RBDEC	COM04	$ 532,971	$ 239,695	$ 127,958	$ 17,124	$ 1,839	$ 146,355
73											
74	**Distribution Structures & Equipment**										
75	Demand		NCRB	RBDSD	DEM04	$ 53,226,490	$ 28,280,653	$ 13,761,610	$ 1,063,972	$ 295,901	$ 9,824,355
76											
77											
78	**Distribution Mains**										
79	Low/Medium Pressure - Demand		NCRB	RBDMD	DEM05a	$ 70,558,775	$ 44,788,728	$ 21,735,413	$ 1,614,045	$ 455,731	$ 1,964,859
80	Low/Medium Pressure - Customer		NCRB	RBDMC	CUSTPT01a	186,854,890	172,050,186	14,673,504	111,542	1,141	18,517
81	High Pressure - Demand		NCRB	RBDMD	DEM05	13,970,753	7,423,033	3,612,112	279,269	77,667	2,578,671
82	High Pressure - Customer		NCRB	RBDMC	CUSTPT01	14,228,121	13,098,613	1,117,174	8,709	130	3,494
83	Total Distribution Mains					$ 285,612,538	$ 237,360,560	$ 41,138,203	$ 2,013,564	$ 534,670	$ 4,565,541
84											
85	**Services**										
86	Customer		NCRB	RBSC	CUST02	$ 251,702,188	$ 195,732,297	$ 54,792,786	$ 831,179	$ 12,434	$ 333,492
87											
88	**Meters**										
89	Customer		NCRB	RBMC	CUST03	$ 65,932,949	$ 40,698,428	$ 21,337,993	$ 1,513,586	$ 107,786	$ 2,275,156
90											
91	**Customer Accounts**										
92	Customer		NCRB	RBCAC	CUSTPT04	$ 4,090,962	$ 3,482,866	$ 594,104	$ 4,631	$ 69	$ 9,291
93											
94	**Customer Service**										
95	Customer		NCRB	RBCSC	CUSTPT05	$ 428,992	$ 365,225	$ 62,300	$ 486	$ 7	$ 974
96											
97	Total			RBT		$ 1,052,349,977	$ 741,469,107	$ 243,310,119	$ 14,445,380	$ 1,942,049	$ 51,183,321

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3, 4	Description		Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
98											
99											
100											
101	**Operation and Maintenance Expenses**										
102											
103	**Procurement Expenses**										
104	Demand		OMT	OMGSD	DEM01	$ 203,082	$ 132,328	$ 64,392	$ 4,978	$ 1,385	$ -
105	Commodity		OMT	OMGSC	COM01	1,526,751	946,559	505,307	67,622	7,264	-
106	Total Procurement Expenses			OMGST		$ 1,729,834	$ 1,078,886	$ 569,698	$ 72,600	$ 8,649	$ -
107											
108	**Storage**										
109	Demand		OMT	OMSD	DEM02	$ 4,954,049	$ 3,276,275	$ 1,521,913	$ 126,180	$ -	$ 29,680
110	Commodity		OMT	OMSC	COM02	9,776,777	6,261,343	3,223,496	291,938	-	-
111	Total Storage			OMST		$ 14,730,826	$ 9,537,618	$ 4,745,409	$ 418,118	$ -	$ 29,680
112											
113	**Transmission**										
114	Demand Non-Storage Related		OMT	OMTD	DEM04	$ 17,851,545	$ 9,485,001	$ 4,615,484	$ 356,844	$ 99,242	$ 3,294,974
115	Storage Related		OMT	OMTC	DEM03	3,512,736	2,323,088	1,079,134	89,470	-	21,045
116	Total Transmission			OMTRT		$ 21,364,281	$ 11,808,089	$ 5,694,617	$ 446,314	$ 99,242	$ 3,316,019
117											
118	**Distribution Expenses**										
119	Commodity		OMT	OMDEC	COM04	$ 1,949,453	$ 876,735	$ 468,032	$ 62,634	$ 6,728	$ 535,325
120											
121	**Distribution Structures & Equipment**										
122	Demand		OMT	OMDSD	DEM04	$ 5,125,034	$ 2,723,067	$ 1,325,068	$ 102,447	$ 28,491	$ 945,960
123											
124	**Distribution Mains**										
125	Low/Medium Pressure - Demand		OMT	OMDMD	DEM05a	$ 8,003,374	$ 5,080,317	$ 2,465,415	$ 183,079	$ 51,693	$ 222,871
126	Low/Medium Pressure - Customer		OMT	OMDMC	CUSTOM01a	17,569,195	16,176,129	1,380,237	10,980	107	1,743
127	High Pressure - Demand		OMT	OMDMD	DEM05	1,389,384	738,217	359,223	27,773	7,724	256,447
128	High Pressure - Customer		OMT	OMDMD	CUSTOM01	1,253,752	1,154,148	98,482	803	11	308
129	Total Distribution Mains					$ 28,215,705	$ 23,148,811	$ 4,303,356	$ 222,634	$ 59,536	$ 481,369
130											
131	**Services**										
132	Customer		OMT	OMSC	CUST02	$ 11,801,616	$ 9,177,344	$ 2,569,082	$ 38,972	$ 583	$ 15,637
133											
134	**Meters**										
135	Customer		OMT	OMMC	CUST03	$ 6,445,258	$ 3,978,464	$ 2,085,890	$ 147,960	$ 10,537	$ 222,407
136											
137	**Customer Accounts**										
138	Customer		OMT	OMCAC	CUSTOM04	$ 14,963,550	$ 12,737,790	$ 2,173,801	$ 17,714	$ 253	$ 33,992
139											
140	**Customer Service**										
141	Customer		OMT	OMCSC	CUSTOM05	$ 1,569,126	$ 1,335,726	$ 227,952	$ 1,858	$ 27	$ 3,564
142											
143	Total			OMTT		$ 107,894,684	$ 76,402,530	$ 24,162,905	$ 1,531,250	$ 214,045	$ 5,583,954
144											
145											

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Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					**Allocation**	**Total**	**Residential**	**Commercial**	**Industrial**	**As Available Gas Service**	**Firm Transportation Service**
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
146											
147	**Payroll Expenses**										
148											
149	**Procurement Expenses**										
150	Demand		LBTOT	LBGSD	DEM01	$ 102,466	$ 66,766	$ 32,489	$ 2,512	$ 699	$ -
151	Commodity		LBTOT	LBGSC	COM01	770,325	477,588	254,953	34,119	3,665	-
152	Total Procurement Expenses			LBGST		$ 872,790	$ 544,354	$ 287,442	$ 36,631	$ 4,364	$ -
153											
154	**Storage**										
155	Demand		LBTOT	LBSD	DEM02	$ 1,630,747	$ 1,078,467	$ 500,975	$ 41,535	$ -	$ 9,770
156	Commodity		LBTOT	LBSC	COM02	3,423,550	2,192,545	1,128,777	102,228	-	-
157	Total Storage			LBST		$ 5,054,297	$ 3,271,011	$ 1,629,752	$ 143,764	$ -	$ 9,770
158											
159	**Transmission**										
160	Demand Non-Storage Related		LBTOT	LBTD	DEM04	$ 3,037,891	$ 1,614,113	$ 785,441	$ 60,726	$ 16,888	$ 560,723
161	Storage Related		LBTOT	LBTC	DEM03	597,781	395,332	183,642	15,226	-	3,581
162	Total Transmission			LBTRT		$ 3,635,672	$ 2,009,445	$ 969,083	$ 75,952	$ 16,888	$ 564,304
163											
164	**Distribution Expenses**										
165	Commodity		LBTOT	LBDEC	COM04	$ 1,034,383	$ 465,197	$ 248,339	$ 33,234	$ 3,570	$ 284,044
166											
167	**Distribution Structures & Equipment**										
168	Demand		LBTOT	LBDSD	DEM04	$ 2,080,540	$ 1,105,446	$ 537,920	$ 41,589	$ 11,566	$ 384,019
169											
170	**Distribution Mains**										
171	Low/Medium Pressure - Demand		LBTOT	LBDMD	DEM05a	$ 2,192,756	$ 1,391,900	$ 675,472	$ 50,160	$ 14,163	$ 61,062
172	Low/Medium Pressure - Customer		LBTOT	LBDMC	CUSTOM01a	4,813,589	4,431,918	378,156	3,008	29	477
173	High Pressure - Demand		LBTOT	LBDMC	DEM05	380,662	202,256	98,419	7,609	2,116	70,261
174	High Pressure - Customer		LBTOT	LBDMC	CUSTOM01	343,502	316,212	26,982	220	3	84
175	Total Distribution Mains					$ 7,730,508	$ 6,342,286	$ 1,179,029	$ 60,997	$ 16,311	$ 131,885
176											
177	**Services**										
178	Customer		LBTOT	LBSC	CUST02	$ 3,124,844	$ 2,429,987	$ 680,244	$ 10,319	$ 154	$ 4,140
179											
180	**Meters**										
181	Customer		LBTOT	LBMC	CUST03	$ 2,498,089	$ 1,541,995	$ 808,461	$ 57,347	$ 4,084	$ 86,202
182											
183	**Customer Accounts**										
184	Customer		LBTOT	LBCAC	CUSTOM04	$ 4,830,644	$ 4,112,108	$ 701,763	$ 5,718	$ 82	$ 10,973
185											
186	**Customer Service**										
187	Customer		LBTOT	LBCSC	CUSTOM05	$ 297,372	$ 253,139	$ 43,200	$ 352	$ 5	$ 676
188											
189	Total			LBTT		$ 31,159,141	$ 22,074,968	$ 7,085,232	$ 465,902	$ 57,025	$ 1,476,013
190											
191											
192											

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Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
193											
194	**Depreciation Expenses**										
195											
196	**Procurement Expenses**										
197	Demand		DEPREX	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
198	Commodity		DEPREX	DEGSC	COM01	-	-	-	-	-	-
199	Total Procurement Expenses			DEGST		$ -	$ -	$ -	$ -	$ -	$ -
200											
201	**Storage**										
202	Demand		DEPREX	DESD	DEM02	$ 6,200,382	$ 4,100,516	$ 1,904,794	$ 157,925	$ -	$ 37,147
203	Commodity		DEPREX	DESC	COM02	-	-	-	-	-	-
204	Total Storage			DEST		$ 6,200,382	$ 4,100,516	$ 1,904,794	$ 157,925	$ -	$ 37,147
205											
206	**Transmission**										
207	Demand Non-Storage Related		DEPREX	DETD	DEM04	$ 5,228,200	$ 2,777,882	$ 1,351,741	$ 104,509	$ 29,065	$ 965,002
208	Storage Related		DEPREX	DETC	DEM03	1,028,779	680,365	316,047	26,203	-	6,164
209	Total Transmission			DETT		$ 6,256,978	$ 3,458,247	$ 1,667,788	$ 130,712	$ 29,065	$ 971,166
210											
211	**Distribution Expenses**										
212	Commodity		DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
213											
214	**Distribution Structures & Equipment**										
215	Demand		DEPREX	DEDSD	DEM04	$ 1,815,242	$ 964,486	$ 469,327	$ 36,286	$ 10,091	$ 335,051
216											
217	**Distribution Mains**										
218	Low/Medium Pressure - Demand		DEPREX	DEDMD	DEM05a	$ 3,302,319	$ 2,096,219	$ 1,017,269	$ 75,541	$ 21,329	$ 91,960
219	Low/Medium Pressure - Customer		DEPREX	DEDMC	CUSTOM01a	7,249,328	6,674,526	569,507	4,530	44	719
220	High Pressure - Demand		DEPREX	DEDMD	DEM05	573,282	304,600	148,221	11,460	3,187	105,814
221	High Pressure - Customer		DEPREX	DEDMC	CUSTOM01	517,318	476,220	40,635	331	5	127
222	Total Distribution Mains					$ 11,642,246	$ 9,551,565	$ 1,775,633	$ 91,862	$ 24,565	$ 198,621
223											
224	**Services**										
225	Customer		DEPREX	DESC	CUST02	$ 16,854,710	$ 13,106,804	$ 3,669,084	$ 55,658	$ 833	$ 22,332
226											
227	**Meters**										
228	Customer		DEPREX	DEMC	CUST03	$ 4,545,328	$ 2,805,694	$ 1,471,012	$ 104,345	$ 7,431	$ 156,846
229											
230	**Customer Accounts**										
231	Customer		DEPREX	DECAC	CUSTOM04	$ -	$ -	$ -	$ -	$ -	$ -
232											
233	**Customer Service**										
234	Customer		DEPREX	DECSC	CUSTOM05	$ -	$ -	$ -	$ -	$ -	$ -
235											
236	Total			DET		$ 47,314,886	$ 33,987,312	$ 10,957,639	$ 576,788	$ 71,985	$ 1,721,162
237											

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Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3 4	Description		Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
238											
239	**Regulatory Credits**										
240											
241	**Procurement Expenses**										
242	Demand		REGCR	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
243	Commodity		REGCR	DEGSC	COM01	-	-	-	-	-	-
244	Total Procurement Expenses			DEGST		$ -	$ -	$ -	$ -	$ -	$ -
245											
246	**Storage**										
247	Demand		REGCR	DESD	DEM02	$ -	$ -	$ -	$ -	$ -	$ -
248	Commodity		REGCR	DESC	COM02	-	-	-	-	-	-
249	Total Storage			DEST		$ -	$ -	$ -	$ -	$ -	$ -
250											
251	**Transmission**										
252	Demand Non-Storage Related		REGCR	DETD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
253	Storage Related		REGCR	DETC	DEM03	-	-	-	-	-	-
254	Total Transmission			DETT		$ -	$ -	$ -	$ -	$ -	$ -
255											
256	**Distribution Expenses**										
257	Commodity		REGCR	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
258											
259	**Distribution Structures & Equipment**										
260	Demand		REGCR	DEDSD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
261											
262	**Distribution Mains**										
263	Low/Medium Pressure - Demand		REGCR	DEDMD	DEM05a	$ -	$ -	$ -	$ -	$ -	$ -
264	Low/Medium Pressure - Customer		REGCR	DEDMC	CUSTOM01a	-	-	-	-	-	-
265	High Pressure - Demand		REGCR	DEDMD	DEM05	-	-	-	-	-	-
266	High Pressure - Customer		REGCR	DEDMC	CUSTOM01	-	-	-	-	-	-
267	Total Distribution Mains					$ -	$ -	$ -	$ -	$ -	$ -
268											
269	**Services**										
270	Customer		REGCR	DESC	CUST02	$ -	$ -	$ -	$ -	$ -	$ -
271											
272	**Meters**										
273	Customer		REGCR	DEMC	CUST03	$ -	$ -	$ -	$ -	$ -	$ -
274											
275	**Customer Accounts**										
276	Customer		REGCR	DECAC	CUSTOM04	$ -	$ -	$ -	$ -	$ -	$ -
277											
278	**Customer Service**										
279	Customer		REGCR	DECSC	CUSTOM05	$ -	$ -	$ -	$ -	$ -	$ -
280											
281	Total			RCR		$ -	$ -	$ -	$ -	$ -	$ -

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Class Allocation

	Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
282										
283	**Accretion Expense**									
284										
285	**Procurement Expenses**									
286	Demand	ACCRE	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
287	Commodity	ACCRE	DEGSC	COM01	-	-	-	-	-	-
288	Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -
289										
290	**Storage**									
291	Demand	ACCRE	DESD	DEM02	$ -	$ -	$ -	$ -	$ -	$ -
292	Commodity	ACCRE	DESC	COM02	-	-	-	-	-	-
293	Total Storage		DEST		$ -	$ -	$ -	$ -	$ -	$ -
294										
295	**Transmission**									
296	Demand Non-Storage Related	ACCRE	DETD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
297	Storage Related	ACCRE	DETC	DEM03	-	-	-	-	-	-
298	Total Transmission		DETT		$ -	$ -	$ -	$ -	$ -	$ -
299										
300	**Distribution Expenses**									
301	Commodity	ACCRE	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
302										
303	**Distribution Structures & Equipment**									
304	Demand	ACCRE	DEDSD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
305										
306	**Distribution Mains**									
307	Low/Medium Pressure - Demand	ACCRE	DEDMD	DEM05a	$ -	$ -	$ -	$ -	$ -	$ -
308	Low/Medium Pressure - Customer	ACCRE	DEDMC	CUSTOM01a	-	-	-	-	-	-
309	High Pressure - Demand	ACCRE	DEDMD	DEM05	-	-	-	-	-	-
310	High Pressure - Customer	ACCRE	DEDMC	CUSTOM01	-	-	-	-	-	-
311	Total Distribution Mains				$ -	$ -	$ -	$ -	$ -	$ -
312										
313	**Services**									
314	Customer	ACCRE	DESC	CUST02	$ -	$ -	$ -	$ -	$ -	$ -
315										
316	**Meters**									
317	Customer	ACCRE	DEMC	CUST03	$ -	$ -	$ -	$ -	$ -	$ -
318										
319	**Customer Accounts**									
320	Customer	ACCRE	DECAC	CUSTOM04	$ -	$ -	$ -	$ -	$ -	$ -
321										
322	**Customer Service**									
323	Customer	ACCRE	DECSC	CUSTOM05	$ -	$ -	$ -	$ -	$ -	$ -
324										
325	Total		ACC		$ -	$ -	$ -	$ -	$ -	$ -

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Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
326											
327	**ITC Amortization**										
328											
329	**Procurement Expenses**										
330	Demand		ITCAM	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
331	Commodity		ITCAM	DEGSC	COM01	-	-	-	-	-	-
332	Total Procurement Expenses			DEGST		$ -	$ -	$ -	$ -	$ -	$ -
333											
334	**Storage**										
335	Demand		ITCAM	DESD	DEM02	$ (77)	$ (51)	$ (24)	$ (2)	$ -	$ (0)
336	Commodity		ITCAM	DESC	COM02	-	-	-	-	-	-
337	Total Storage			DEST		$ (77)	$ (51)	$ (24)	$ (2)	$ -	$ (0)
338											
339	**Transmission**										
340	Demand Non-Storage Related		ITCAM	DETD	DEM04	$ (73)	$ (39)	$ (19)	$ (1)	$ (0)	$ (13)
341	Storage Related		ITCAM	DETC	DEM03	(14)	(9)	(4)	(0)	-	(0)
342	Total Transmission			DETT		$ (87)	$ (48)	$ (23)	$ (2)	$ (0)	$ (13)
343											
344	**Distribution Expenses**										
345	Commodity		ITCAM	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
346											
347	**Distribution Structures & Equipment**										
348	Demand		ITCAM	DEDSD	DEM04	$ (25)	$ (13)	$ (6)	$ (1)	$ (0)	$ (5)
349											
350	**Distribution Mains**										
351	Low/Medium Pressure - Demand		ITCAM	DEDMD	DEM05a	$ (54)	$ (34)	$ (17)	$ (1)	$ (0)	$ (2)
352	Low/Medium Pressure - Customer		ITCAM	DEDMC	CUSTOM01a	(119)	(110)	(9)	(0)	(0)	(0)
353	High Pressure - Demand		ITCAM	DEDMD	DEM05	(9)	(5)	(2)	(0)	(0)	(2)
354	High Pressure - Customer		ITCAM	DEDMC	CUSTOM01	(8)	(8)	(1)	(0)	(0)	(0)
355	Total Distribution Mains					$ (191)	$ (157)	$ (29)	$ (2)	$ (0)	$ (3)
356											
357	**Services**										
358	Customer		ITCAM	DESC	CUST02	$ (164)	$ (128)	$ (36)	$ (1)	$ (0)	$ (0)
359											
360	**Meters**										
361	Customer		ITCAM	DEMC	CUST03	$ (39)	$ (24)	$ (13)	$ (1)	$ (0)	$ (1)
362											
363	**Customer Accounts**										
364	Customer		ITCAM	DECAC	CUSTOM04	$ -	$ -	$ -	$ -	$ -	$ -
365											
366	**Customer Service**										
367	Customer		ITCAM	DECSC	CUSTOM05	$ -	$ -	$ -	$ -	$ -	$ -
368											
369	Total			ITC		$ (584)	$ (421)	$ (131)	$ (7)	$ (1)	$ (23)

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Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
370											
371	**Other Taxes**										
372											
373	**Procurement Expenses**										
374	Demand		OTT	OTTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
375	Commodity		OTT	OTTGSC	COM01	-	-	-	-	-	-
376	Total Procurement Expenses			OTTGST		$ -	$ -	$ -	$ -	$ -	$ -
377											
378	**Storage**										
379	Demand		OTT	OTTSD	DEM02	$ 1,990,090	$ 1,316,112	$ 611,368	$ 50,688	$ -	$ 11,923
380	Commodity		OTT	OTTSC	COM02	-	-	-	-	-	-
381	Total Storage			OTTST		$ 1,990,090	$ 1,316,112	$ 611,368	$ 50,688	$ -	$ 11,923
382											
383	**Transmission**										
384	Demand Non-Storage Related		OTT	OTTTD	DEM04	$ 1,893,063	$ 1,005,835	$ 489,448	$ 37,841	$ 10,524	$ 349,415
385	Storage Related		OTT	OTTTC	DEM03	372,507	246,351	114,436	9,488	-	2,232
386	Total Transmission			OTTTT		$ 2,265,570	$ 1,252,186	$ 603,884	$ 47,329	$ 10,524	$ 351,647
387											
388	**Distribution Expenses**										
389	Commodity		OTT	OTTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
390											
391	**Distribution Structures & Equipment**										
392	Demand		OTT	OTTDSD	DEM04	$ 599,274	$ 318,410	$ 154,941	$ 11,979	$ 3,332	$ 110,612
393											
394	**Distribution Mains**										
395	Low/Medium Pressure - Demand		OTT	OTTDMD	DEM05a	$ 1,342,159	$ 851,965	$ 413,448	$ 30,702	$ 8,669	$ 37,375
396	Low/Medium Pressure - Customer		OTT	OTTDMC	CUSTOM01a	2,946,340	2,712,724	231,465	1,841	18	292
397	High Pressure - Demand		OTT	OTTDMD	DEM05	232,999	123,798	60,241	4,658	1,295	43,006
398	High Pressure - Customer		OTT	OTTDMC	CUSTOM01	210,253	193,550	16,515	135	2	52
399	Total Distribution Mains					$ 4,731,751	$ 3,882,037	$ 721,669	$ 37,335	$ 9,984	$ 80,725
400											
401	**Services**										
402	Customer		OTT	OTTSC	CUST02	$ 3,936,045	$ 3,060,804	$ 856,834	$ 12,998	$ 194	$ 5,215
403											
404	**Meters**										
405	Customer		OTT	OTTMC	CUST03	$ 942,472	$ 581,760	$ 305,014	$ 21,636	$ 1,541	$ 32,522
406											
407	**Customer Accounts**										
408	Customer		OTT	OTTCAC	CUSTOM04	$ -	$ -	$ -	$ -	$ -	$ -
409											
410	**Customer Service**										
411	Customer		OTT	OTTCSC	CUSTOM05	$ -	$ -	$ -	$ -	$ -	$ -
412											
413	Total			OTTT		$ 14,465,203	$ 10,411,309	$ 3,253,710	$ 181,965	$ 25,575	$ 592,644
414											
415											
416											

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Row	Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
417										
418	**Interest Expense**									
419										
420	**Procurement Expenses**									
421	Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
422	Commodity	INT	INTGSC	COM01	-	-	-	-	-	-
423	Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -
424										
425	**Storage**									
426	Demand	INT	INTSD	DEM02	$ 2,434,346	$ 1,609,913	$ 747,846	$ 62,003	$ -	$ 14,584
427	Commodity	INT	INTSC	COM02	-	-	-	-	-	-
428	Total Storage		INTST		$ 2,434,346	$ 1,609,913	$ 747,846	$ 62,003	$ -	$ 14,584
429										
430	**Transmission**									
431	Demand Non-Storage Related	INT	INTTD	DEM04	$ 2,315,659	$ 1,230,371	$ 598,709	$ 46,289	$ 12,873	$ 427,416
432	Storage Related	INT	INTTC	DEM03	455,664	301,345	139,983	11,606	-	2,730
433	Total Transmission		INTTT		$ 2,771,322	$ 1,531,717	$ 738,692	$ 57,895	$ 12,873	$ 430,146
434										
435	**Distribution Expenses**									
436	Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
437										
438	**Distribution Structures & Equipment**									
439	Demand	INT	INTDSD	DEM04	$ 733,053	$ 389,490	$ 189,529	$ 14,653	$ 4,075	$ 135,304
440										
441	**Distribution Mains**									
442	Low/Medium Pressure - Demand	INT	INTDMD	DEM05a	$ 1,641,775	$ 1,042,152	$ 505,744	$ 37,556	$ 10,604	$ 45,719
443	Low/Medium Pressure - Customer	INT	INTDMC	CUSTOM01a	3,604,062	3,318,295	283,135	2,252	22	358
444	High Pressure - Demand	INT	INTDMD	DEM05	285,012	151,434	73,689	5,697	1,584	52,606
445	High Pressure - Customer	INT	INTDMC	CUSTOM01	257,189	236,757	20,202	165	2	63
446	Total Distribution Mains				$ 5,788,038	$ 4,748,639	$ 882,770	$ 45,670	$ 12,213	$ 98,746
447										
448	**Services**									
449	Customer	INT	INTSC	CUST02	$ 4,814,704	$ 3,744,079	$ 1,048,108	$ 15,899	$ 238	$ 6,379
450										
451	**Meters**									
452	Customer	INT	INTMC	CUST03	$ 1,152,864	$ 711,628	$ 373,103	$ 26,466	$ 1,885	$ 39,782
453										
454	**Customer Accounts**									
455	Customer	INT	INTCAC	CUSTOM04	$ -	$ -	$ -	$ -	$ -	$ -
456										
457	**Customer Service**									
458	Customer	INT	INTCSC	CUSTOM05	$ -	$ -	$ -	$ -	$ -	$ -
459										
460	Total		INTT		$ 17,694,326	$ 12,735,466	$ 3,980,048	$ 222,586	$ 31,284	$ 724,942
461										

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
462											
463	**Net Operating Income -- Adjusted Forecast Period**										
464											
465	**Operating Revenues**										
466	Sales and Transportation				REV01	354,943,652	238,109,178	101,307,441	8,488,908	419,670	6,618,455
467	Interdepartmental Sales				REV01	3,215,355	2,156,978	917,721	76,899	3,802	59,955
468	Forfeited Discounts				REVFD	$ 1,097,667	887,050	197,248	13,229	-	139
469	Rent from Gas Property				RBT	$ 164,430	115,855	38,017	2,257	303	7,997
470	Miscellaneous/Other Revenue			REVMSR	REVMISC	110,812	78,638	30,276	200	-	1,698
471											
472	Total Operating Revenues			TOR		$ 359,531,916	$ 241,347,700	$ 102,490,703	$ 8,581,494	$ 423,775	$ 6,688,244
473											
474	**Pro-Forma Adjustments to Revenues**										
475	Adjustment to eliminate gas line tracker revenues				REVGLT	(10,181,350)	$ (6,886,665)	$ (2,860,959)	$ (333,499)	$ (18,776)	$ (81,451)
476	Adjustment to eliminate gas supply cost recoveries				REVGSC	(115,476,300)	$ (73,041,197)	$ (38,749,209)	$ (3,507,061)	$ (178,833)	$ -
477	Adj to eliminate GSC recoveries Interdepartmental Sales				REV01	(953,712)	$ (639,785)	$ (272,207)	$ (22,809)	$ (1,128)	$ (17,783)
478	Removal of DSM Revenues				REVADJ4	(369,541)	(235,706)	(133,397)	-	(437)	-
479	Total Revenue Adjustments					$ (126,980,903)	$ (80,803,354)	$ (42,015,773)	$ (3,863,369)	$ (199,173)	$ (99,234)
480											
481	**Total Adjusted Revenue**			TREVADJ		$ 232,551,013	$ 160,544,346	$ 60,474,931	$ 4,718,125	$ 224,602	$ 6,589,010
482											
483	**Expenses**										
484	Operation and Maintenance Expenses					$ 107,894,684	$ 76,402,530	$ 24,162,905	$ 1,531,250	$ 214,045	$ 5,583,954
485	Depreciation and Amortization Expenses					47,314,886	33,987,312	10,957,639	576,788	71,985	1,721,162
486	Other Expenses (ITC amortization, Reg Credits, Accretion)					(584)	(421)	(131)	(7)	(1)	(23)
487	Other Taxes					14,465,203	10,411,309	3,253,710	181,965	25,575	592,644
488	Total Operating Expenses			TOE		$ 169,674,189	$ 120,800,730	$ 38,374,123	$ 2,289,996	$ 311,604	$ 7,897,736
489											
490											
491											
492											

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E		F		G		H		I		J		K
3					Allocation		Total		Residential		Commercial		Industrial		As Available Gas Service		Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**		**System**		**(RGS)**		**(CGS)**		**(IGS)**		**(AAGS)**		**(FT)**
493																	
517																	
518	Net Income Before Income Taxes					$	62,876,825	$	39,743,616	$	22,100,807	$	2,428,129	$	(87,002)	$	(1,308,726)
519																	
520	Income Taxes				TXINC	$	9,213,040		5,507,158		3,694,954		449,726		(24,119)		(414,680)
521																	
522	Net Operating Income (Pro-Forma)			TOM		$	53,663,785	$	34,236,458	$	18,405,853	$	1,978,403	$	(62,883)	$	(894,046)
523																	
524	**Unadjusted Net Cost Rate Base**					$	1,052,349,977	$	741,469,107	$	243,310,119	$	14,445,380	$	1,942,049	$	51,183,321
525	**Depreciation Adjustment**				DET	$	-		-		-		-		-		-
526	**Cash Working Capital Adjustment**				OMTT	$	-		-		-		-		-		-
527	**Net Cost Rate Base**					$	1,052,349,977	$	741,469,107	$	243,310,119	$	14,445,380	$	1,942,049	$	51,183,321
528	**Rate of Return -- Pro-Forma**						**5.10%**		**4.62%**		**7.56%**		**13.70%**		**-3.24%**		**-1.75%**
529																	

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3										As Available	Firm Transportation
4	Description		Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	Gas Service (AAGS)	Service (FT)
556											
557											
558	**Net Operating Income -- Proposed Rates**										
559											
560	**Test Year Operating Income**					$ 53,663,785	$ 34,236,458	$ 18,405,853	$ 1,978,403	$ (62,883)	$ (894,046)
561											
562	**Proposed Increase**					$ 29,977,693	$ 22,318,158	$ 4,921,072	$ (1,900)	$ 109,486	2,630,877
563	**Adjustment to Interdepartmental Sales**				REV01	$ 1,592	1,068	454	38	2	30
564	**Miscellaneous/Other Revenue**				REVMISC	$ 8,769	6,223	2,396	16	-	134
565											
566	**Incremental Income Taxes**				24.85%	7,451,867	5,547,752	1,223,568	(459)	27,207	653,799
567	**Incremental Uncollectable Accounts Expense**				0.203%	60,876	45,321	9,996	(4)	222	5,341
568	**Incremental Commission Fees**				0.20%	59,976	44,651	9,848	(4)	219	5,262
569					25.25%						
570	**Net Operating Income Adjusted for Increase**					76,079,120	50,924,184	22,086,364	1,977,023	18,957	1,072,592
571											
572	**Net Cost Rate Base (Same as Above)**					$ 1,052,349,977	$ 741,469,107	$ 243,310,119	$ 14,445,380	$ 1,942,049	$ 51,183,321
573											
574	**Rate of Return -- Proposed**					**7.23%**	**6.87%**	**9.08%**	**13.69%**	**0.98%**	**2.10%**
575											
576											
577											

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3					Allocation	Total	Residential	Commercial	Industrial	As Available Gas Service	Firm Transportation Service
4	**Description**		**Ref**	**Name**	**Vector**	**System**	**(RGS)**	**(CGS)**	**(IGS)**	**(AAGS)**	**(FT)**
578											
579	**Allocation Factors**										
580											
581	**Commodity**										
582	Procurement Expenses			COM01		31,454,934	19,501,502	10,410,592	1,393,182	149,658	-
583							0.619982	0.330968	0.044291	0.004758	-
584	Storage			COM02		20,303,610	13,003,045	6,694,292	606,273		-
585	Transmission			COM03		20,303,610	13,003,045	6,694,292	606,273	-	-
586	Distribution			COM04		43,362,337	19,501,502	10,410,592	1,393,182	149,658	11,907,403
587	Adjusted Deliveries					43,362,337	19,501,502	10,410,592	1,393,182	149,658	11,907,403
588											
589	**Demand**										
590	Procurement Expenses			DEM01		494,887	322,467	156,915	12,132	3,374	-
591	Storage			DEM02		11,680,000	7,724,367	3,588,166	297,491		69,976
592							0.661333	0.307206	0.025470		0.005991
593	Transmission Storage Related			DEM03		11,680,000	7,724,367	3,588,166	297,491	-	69,976
594	Distribution Structures			DEM04		606,908	322,467	156,915	12,132	3,374	112,021
595	High Pressure Distrib Mains			DEM05		606,908	322,467	156,915	12,132	3,374	112,021
596	Low/Med Pres. Distrib Mains			DEM05a		508,004	322,467	156,489	11,621	3,281	14,146
597											
598	**Customer Plant Allocators**										
599	Customer Count (13 Month Average)					327,622	301,613	25,724	201	3	80
600	High Pressure Distrib Mains (13 Month Avg.)			CUSTPT01		327,622	301,613	25,724	201	3	80
601	Low/Med Pres. Distrib Mains			CUSTPT01a		327,567	301,613	25,723	196	2	32
602	Customer Accounts			CUSTPT04		354,274	301,613	51,449	401	6	805
603	Customer Service			CUSTPT05		354,274	301,613	51,449	401	6	805
604											
605	**Customer O&M Allocators**										
606	Customer Count (12 Month Average)					327,692	301,659	25,740	210	3	81
607	High Pressure Distrib Mains (12 Month Avg.)			CUSTOM01		327,692	301,659	25,740	210	3	81
608	Low/Med Pres. Distrib Mains			CUSTOM01a		327,637	301,659	25,739	205	2	33
609	Customer Accounts			CUSTOM04		354,369	301,659	51,480	420	6	805
610	Customer Service			CUSTOM05		354,369	301,659	51,480	420	6	805
611											
612											
613	Services			CUST02		391,144,507	304,167,449	85,147,839	1,291,650	19,323	518,246
614	Meters			CUST03		179,686,124	110,914,844	58,152,128	4,124,954	293,747	6,200,451
615											
616											
617											
618											
619											

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended June 30, 2022

Class Allocation

	A	B	C	D	E	F	G	H	I	J	K
3										As Available	Firm Transportation
4	**Description**		**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential (RGS)**	**Commercial (CGS)**	**Industrial (IGS)**	**Gas Service (AAGS)**	**Service (FT)**
620											
621	**Allocation Factors Continued**										
622											
623	**Taxable Income**										
624											
625	Net Income Before Income Tax			NIBIT		$ 62,876,825	$ 39,743,616	$ 22,100,807	$ 2,428,129	$ (87,002)	$ (1,308,726)
626											
627	Interest Expense			INT		$ 17,694,326	$ 12,735,466	$ 3,980,048	$ 222,586	$ 31,284	$ 724,942
628	Interest Adjustment					$ -	-	-	-	-	-
629											
630	Taxable Income			TXINC		$ 45,182,499	$ 27,008,150	$ 18,120,759	$ 2,205,543	$ (118,286)	$ (2,033,667)
631											
632	Total Distribution Expense			DISTRT		$ 53,537,067	$ 39,904,420	$ 10,751,427	$ 574,646	$ 105,875	$ 2,200,698
633											
634	Number of Customers					327,622	301,613	25,724	201	3	80
635											
636	Services Cost					391,144,507	304,167,449	85,147,839	1,291,650	19,323	518,246
637							$ 1,008.47	$ 3,310.00	$ 6,440.91	$ 6,440.91	$ 6,440.91
638											
639	Actual Revenue			REV01		354,943,652	238,109,178	101,307,441	8,488,908	419,670	6,618,455
640	DSM Allocation			REVADJ4		369,541	235,706	133,397	-	437	-
641	Forfeited Discounts			REVFD		1,079,328	872,230	193,953	13,008	-	137
642	Miscellaneous Revenue Allocation			REVMISC		108,583	77,057	29,667	196		1,663
643	GSC Revenue			REVGSC		115,476,300	73,041,197	38,749,209	3,507,061	178,833	
644	Removal of GLT Revenue			REVGLT		10,181,350	6,886,665	2,860,959	333,499	18,776	81,451
645	Pro-Forma Adjustments			PROFO		(126,980,903)	(80,803,354)	(42,015,773)	(3,863,369)	(199,173)	(99,234)
646											
647	High Pressure System			RBTHP		28,198,874	20,521,646	4,729,286	287,978	77,798	2,582,166

Exhibit WSS-38

Gas Cost of Service Study
Storage Allocation
(Louisville Gas and Electric Company)

Calculation of Maximum Class Demands On February 26th Design Day (4 Degrees) for Determination of Demand Allocation Factors

	Total	Residential Rate RGS	Commercial Rate CGS	Industrial Rate IGS	Rate FT 5 Percent Balancing
Calculated Daily Requirements at 4 Degrees (61 HDDs)	416,029	276,944	129,292	9,793	0
Percentage of Total		66.57%	31.08%	2.35%	0.00%

Allocation of Underground Storage

	Storage Withdrawals	Residential Rate RGS	Commercial Rate CGS	Industrial Rate IGS	Rate FT 5 Percent Balancing
Total Allocated Withdrawals Thru February 28th	8,316,075	5,485,002	2,542,658	218,439	69,976
Balance of Working Gas Allocated on the Basis of 4 Degrees (Feb. 26th)	3,363,925	2,239,365	1,045,508	79,052	0
Total Working Gas Cycled	11,680,000	7,724,367	3,588,166	297,491	69,976
Total Allocation Factor For Underground Storage	1.000000	0.661333	0.307206	0.025470	0.005991

Exhibit WSS-39

Summary Results of Lead-Lag Study

Kentucky Utilities Company
Cash Working Capital Analysis
2020 Kentucky Rate Case
Revenue Lag Days Based on the Year Ended December 31, 2019
Expense Lead Days Based on the Year Ended December 31, 2017

Lead/Lag Days Summary

	Lag Days
Revenue	
Meter Reading	15.21
Billing	4.20
Collection	25.09
Bank	1.00
Total	**45.50**

	Lead Days
O&M Expense	
Fuel: Coal	27.28
Fuel: Gas	39.32
Fuel: Oil	17.32
Other Non-Fuel Commodities	27.76
Purchased Power	23.66
Payroll Expense	13.01
Pension Expense	-
OPEB Expense	-
Team Incentive Award Compensation	244.79
401k Match Expense	22.56
Retirement Income Account Expense	283.50
Uncollectible Expense	131.70
Major Storm Damage Expense	41.74
Charges from Affiliates	25.39
Other O&M	48.05
Depreciation and Amortization Expense	
Depreciation and Amortization	-
Regulatory Debits	-
Amortization of Regulatory Assets	-
Amortization of Regulatory Liabilities	-
Income Tax Expense	
Current: Federal	37.50
Current: State	37.50
Deferred: Federal and State (Including ITC)	-
Taxes Other Than Income	
Property Tax Expense	157.57
Payroll Tax Expense	35.64
Other Taxes	(152.00)
Interest Expense	88.65
Sales Tax	39.80
School Tax	34.95
Franchise Fees	67.16

Louisville Gas and Electric Company
Cash Working Capital Analysis
2020 Kentucky Rate Case
Revenue Lag Days Based on the Year Ended December 31, 2019
Expense Lead Days Based on the Year Ended December 31, 2017

Lead/Lag Days Summary

	Lag Days	
	Electric	**Gas**
Revenue		
Meter Reading	15.21	15.21
Billing	4.29	4.28
Collection	23.77	23.77
Bank	1.00	1.00
Total	**44.27**	**44.26**

	Lead Days	
	Electric	**Gas**
O&M Expense		
Fuel: Coal	24.36	n/a
Fuel: Gas	38.99	n/a
Fuel: Oil	8.40	n/a
Other Non-Fuel Commodities	26.87	n/a
Purchased Gas	n/a	39.66
No-Notice Storage Injections and Withdrawals	n/a	-
Purchased Power	28.37	n/a
Payroll Expense	12.00	12.00
Pension Expense	-	-
OPEB Expense	-	-
Team Incentive Award Compensation	245.22	245.22
401k Match Expense	22.99	22.99
Retirement Income Account Expense	283.50	283.50
Uncollectible Expense	174.20	256.34
Major Storm Damage Expense	35.32	35.32
Charges from Affiliates	25.40	25.40
Other O&M	49.19	49.19
Depreciation and Amortization Expense		
Depreciation and Amortization	-	-
Regulatory Debits	-	-
Amortization of Regulatory Assets	-	-
Amortization of Regulatory Liabilities	-	-
Income Tax Expense		
Current: Federal	37.50	37.50
Current: State	37.50	37.50
Deferred: Federal and State (Including ITC)	-	-
Taxes Other Than Income		
Property Tax Expense	216.26	216.26
Payroll Tax Expense	35.48	35.48
Other Taxes	(148.70)	(148.70)
Interest Expense	87.50	87.50
Sales Taxes	39.83	39.83
School Taxes	35.05	35.05
Franchise Fees	100.24	100.24