COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
DR. MARTIN BLAKE
PRINCIPAL
THE PRIME GROUP, LLC

Filed: April 14, 2015

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Q. Please state your name and business address.

A. My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. Are you the same Martin J. Blake who filed Direct Testimony on behalf of Kentucky Utilities Company and Louisville Gas and Electric Company ("KU", "LGE" or "Companies") in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the Testimony that was filed by Mr. Paul Chernick, Mr. Ronald Willhite, Mr. Stephen Baron, Mr. Steve Chriss and Ms. Patricia Kravtin in Case Nos. 2014-00371 and 2014-00372 on March 6, 2015 and to correct and rebut any inaccuracies or inconsistencies in their Testimony.

Residential Electric Basic Service Charges

Q. Does Mr. Chernick's Testimony recognize what properly constitutes a fixed cost and that there are both volumetric and non-volumetric components of fixed cost?

A. No. Mr. Chernick's recommendation regarding the basic service charge is based on a misconception of what constitutes fixed distribution cost, and a misconception of what is included in the volumetric and non-volumetric components of fixed distribution costs. In his Direct Testimony, Mr. Chernick states that "(t)he Company lacks a reasonable basis for its plan to shift allegedly 'fixed' costs from the residential energy charge to the basic service charge."[1] But once meters, services, transformers, poles and conductor are installed to meet customer needs, these distribution costs that have been incurred by the Companies are recorded in the Companies' FERC system of accounts and will not change. Because costs that do not change meet the definition of fixed costs, these distribution costs that have been incurred by the Companies are clearly fixed costs.

Q. Why do you believe that Mr. Chernick does not understand the volumetric and non-volumetric components of existing fixed distribution costs?

A. In his Direct testimony, Mr. Chernick states that "Dr. Blake apparently recognizes the distinction between fixed costs that vary over the long run with customer usage (i.e., "volumetric" demand-related costs) and those that do not (i.e., "non-volumetric" customer-related costs)."[2] This is not what I mean when I classify existing fixed distribution costs as either volumetric or non-volumetric, and the classification of costs as volumetric in the cost of service study in this proceeding has nothing to do with the long run when additional fixed costs may be incurred in the future. The Companies' existing fixed distribution costs have both a volumetric and a non-volumetric component. Non-volumetric fixed distribution costs are classified as customer-related distribution costs and include the cost of the minimum set of existing distribution facilities necessary to provide a customer with access to the electric grid. This

1 Chernick Direct Testimony, Case No. 2014-00371, 3:4-5 and Case No. 2014-00372, 3:4-5
2 Chernick Direct Testimony, Case No. 2014-00371, 5:24 through 6:3 and Case No. 2014-00372, 5:24 through 6:3

minimum set of distribution facilities consists of a meter, service drop, transformer and some minimum amount of poles and conductor without which the customer would not be able to purchase electric energy from the Companies. Volumetric fixed distribution costs are classified as demand-related distribution costs and are related to the size of the existing distribution equipment that the Companies had to install to reliably meet the customer's needs. Even though this size related portion of existing fixed distribution costs is determined by the size of the load that customers have placed on the system, they are nonetheless fixed costs for the Companies as they reflect existing distribution equipment that is currently installed, not fixed costs that may be incurred in the future and that are not yet booked in the Companies' accounts. Mr. Chernick's concept of volumetric fixed costs is totally inaccurate as the costs to which he refers have not yet been incurred, may be incurred in the future and thus, are not fixed. His flawed discussion of demand-related and customer-related fixed distribution costs is based on this misconception. An illustration of his application of this misconception is contained in footnote 4 in his Direct Testimony which states that "shifting recovery of volumetric fixed costs to the basic service charge could further and needlessly increase basic service charges <u>in the future</u>, in order to recover uneconomic plant investment required to meet <u>demand growth</u> resulting from misleading price signals."[3] (emphasis added). Because his recommendations regarding the basic service charge are based on a flawed conception of the volumetric and non-volumetric components of existing fixed

3 Chernick Direct testimony, Case No. 2014-00371, Footnote 4, page 6 and Case No. 2014-00372, Footnote 4, page 6

distribution costs in the cost of service studies submitted by the Companies, they should be ignored by the Commission.

Q. Is this classification of existing fixed distribution costs into demand-related and customer-related components widely accepted in the industry?

A. Yes. This split between customer-related and demand-related fixed distribution costs is recognized in the NARUC Electric Utility Cost Allocation Manual which states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.[4]

In order to be booked into Accounts 364 through 370, the costs had to have already been incurred, and thus are existing fixed distribution costs. The Companies chose to use the zero-intercept method rather than the minimum-size-of-facilities method in classifying existing fixed distribution costs as either customer-related or demand-related.

Q. Why did the Companies choose to use the zero-intercept method for classifying existing fixed distribution costs as either demand-related or customer-related costs?

4 Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992, p. 90.

A. The Companies chose to use the zero-intercept method in classifying existing fixed distribution cost as either customer-related or demand-related because this methodology has been used by the Companies and accepted by the Commission in prior rate cases and also avoids the problem of classifying some customer-related costs as demand-related. This problem of classifying some customer-related costs as demand-related can be summarized as:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[5]

The use of the zero-intercept methodology avoids classifying some demand-related costs as customer-related and is the method preferred by the Companies for classifying existing fixed distribution costs in the cost of service study.

Q. Do you agree with Mr. Chernick's statement that the basic service charge is intended to reflect the incremental costs imposed by the continued presence of a customer who uses very little energy?

A. No. The basic service charge is designed to recover the cost of installing, operating and maintaining the minimum set of equipment necessary to provide a customer with access to the electric grid and is comprised of costs classified as non-volumetric fixed costs. The non-volumetric fixed distribution cost per customer, on which the basic service

5 Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992, p. 95.

charge is based, is properly calculated on an average basis rather than on an incremental basis as proposed by Mr. Chernick. The incremental approach proposed by Mr. Chernick would allow new customers to use existing facilities that have previously been installed to meet customer needs without spreading these fixed costs over all customers served by the existing facilities, including the new customers, as is typically done in developing electric utility rates.[6] Spreading the fixed cost of the minimum set of facilities necessary to serve a customer over all customers would require an average calculation of the cost rather than an incremental calculation of the cost as proposed by Mr. Chernick.

Q: Do you agree with Mr. Chernick's assertion that the non-volumetric distribution cost will vary depending upon the size of the customer's load?

A: No. Mr. Chernick states that "the minimum distribution cost per customer will vary with the usage of the customers served by the distribution equipment. Consequently, the true minimum cost to serve a customer with very little usage is likely to be less than the non-volumetric fixed cost per customer."[7] (emphasis added) Mr. Chernick is incorrectly attempting to bring size into the development of a cost that is meant to convey the cost of providing service that is not size related. The customer-related, non-volumetric fixed distribution cost of providing service to a customer represents the cost

6 Sierra Club Response to LGE-8 which states that "Incremental costs of adding a customer would not include a transformer, because most residential customers do not require a separate transformer, other than to accommodate their load level. Thus, while increasing load by more than a threshold amount would require adding or upgrading a transformer, adding a new customer while keeping load constant would not trigger this need."

7 Chernick Direct Testimony, Case No. 2014-00371, 8:17-21 and Case No. 2014-00372, 8:19-23

of the set of distribution facilities that any customer must have that has no load carrying capability at all, and thus, are not related to the size of the customer's load. It represents zero kVA transformers and zero MCM conductors. By definition, an asset that has no size related characteristics cannot change with the size of the customer. The demand-related portion of the costs represents the costs that vary with the size of the customers load. If the Commission were to adopt Mr. Chernick's recommendation, it would defeat the purpose of splitting costs between customer-related and demand-related cost components in the cost of service study.

Q: Is Mr. Chernick's estimate of the incremental cost to connect a customer an accurate representation of the actual incremental cost of connecting a customer to the system?

A: No. On pages 11 and 12 of his testimony, Mr. Chernick discusses his estimate of the incremental cost of connecting a customer to the system. The cost of service studies submitted by the Companies do not contain any marginal or incremental costs and cannot be used to determine the marginal or incremental cost of providing service. Mr. Chernick seems to understand this concept in spite of his assertion that he estimated the incremental costs of connecting a customer to the system. Mr. Chernick states that "(t)he Company COSS classifies the costs of the Company's existing system between demand-related and energy-related components, and allocates those embedded costs among classes. The COSS is not designed to estimate the incremental costs of serving an additional kilowatt-hour on peak versus off-peak."[8] While I strongly disagree with the argument that the customer charge should recover the marginal cost of connecting a customer to the system, if the customer charge were to be based on this concept, Mr. Chernick's calculation would be the incorrect method for calculating it.

Q. Do you agree with Mr. Chernick's calculation of the basic service charge?

A. No. Chernick Exhibit PLC-2 contains a flawed calculation of the basic service charge. Mr. Chernick claims that the basic service charge should only include installation and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer service expenses.[9] Mr. Chernick does not explain how a customer could purchase electric energy without a transformer and some minimum amount of poles and conductor, which might justify the omission of this equipment from the basic service charge. Mr. Chernick's calculation of the basic service charge is also inconsistent with the NARUC Electric Utility Cost Allocation Manual which makes it clear that some minimum amount of poles, conductor and transformer should be included in the non-volumetric customer-related distribution costs that are included in the calculation of the basic service charge.[10] Mr. Chernick argues that cost classification and allocation of fixed distribution costs as customer-related and demand-related should not be used in developing the basic service charge stating that:

> Regardless of the method used to classify and allocate distribution costs among classes (e.g. zero-intercept, minimum-size, demand), it is not appropriate to use

8 Chernick Direct Testimony, Case No. 2014-00371, 39:14-18 and Case No. 2014-00372, 39:14-18
9 Chernick Direct Testimony, Case No. 2014-00371, 11:11-15 and Case No. 2014-00372, 11:14-18
10 Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992, p. 90.

> the allocation of those costs to classes as a basis for rate design and particularly for determining the fixed monthly charge per customer. (Sierra Club response to Data request LGE-6)

This argument is inconsistent with Commission precedent and electric utility industry practice. If the customer-related costs are not used as a basis for developing the fixed monthly basic service charge, there is no reason for making this distinction in the cost of service study in the first place. Thus, Mr. Chernick's calculation of the basic service charge is fatally flawed and his recommendation to maintain the basic service charge at the current level of $10.75 should be disregarded by the Commission.

Q. Do you agree with Mr. Chernick that increasing the basic service charge as the Companies propose would significantly reduce the incentive for customers to conserve?

A. No. Beginning on page 15 of his Direct Testimony in Case No. 2014-00371, Mr. Chernick argues that the increase in the basic service charge proposed by the Companies in conjunction with a decrease in the energy charge would dampen the price signals for conservation. Compared to the proposed basic service charge of $18.00, the current service charge of $10.75 under-recovers customer-related fixed distribution costs by $7.25 per customer per month. When this under-recovery of $7.25 per customer per month is multiplied by the 5,164,164 customer months for KU's residential rate class during the test year, the result is $37,440,189 in non-volumetric customer-related fixed operating expenses and margins that are being "variablized" and recovered through a kWh energy charge rather than being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is \$0.006 per kWh of fixed operating expenses and margins collected through the energy charge (calculated as \$37,440,189 / 6,197,389,895 kWh = \$0.006 per kWh). However, this is not a measure of the change in the energy charge that the Companies are proposing for the Residential rate class which is also impacted by the requested rate increase. Although Mr. Chernick claims that the Companies' proposal would result in a reduction of the energy price that would reduce the incentive to conserve energy, KU's proposal would result in an increase from the Company's current energy charge of \$0.07744 per kWh for Residential customers to the new energy charge of \$0.08057 per kWh. Contrary to Mr. Chernick's claim, the energy charge proposed by KU would increase rather than decrease and would not reduce the incentive to conserve energy. Thus, the premise on which Mr. Chernick bases his price elasticity analysis is incorrect, as it is calculated using an energy price decrease rather than the actual proposed energy price increase, and Mr. Chernick's analysis and recommendations should be disregarded by the Commission. Although Mr. Chernick appears to believe that it is a good idea to increase the energy charge in order to provide a stronger incentive for conservation and energy efficiency, he has provided no cost causative reason why this should occur. His recommendation for the basic service charge to remain at \$10.75 and to recover through an energy charge the non-volumetric customer-related fixed distribution costs that are not recovered through the basic service charge appears to be based on his claim that rate design has little or no relationship to equity or cost causation, and that the aim of rate design is to elicit desired customer behaviors.[11] By contrast, the Company's rate design recommendations are based solidly on cost causation, which is usually the standard applied by regulatory commissions in deciding whether rates are fair, just and reasonable.

Q. Do you agree with Mr. Chernick that the basic service charge that the Company is proposing would exacerbate the subsidization of larger residential customers' costs by low-usage customers?

A. No. Mr. Chernick has the direction of the subsidization exactly backwards. Because non-volumetric fixed distribution costs are variablized and collected through the energy charge in the energy component of the current rate charged to Residential customers, customers purchasing more kWh than the class average would be subsidizing the non-volumetric fixed costs of customers purchasing less kWh than the class average, which is exactly opposite of what Mr. Chernick claims.

Q. Would the basic service charge proposed by the Companies recover all non-volumetric fixed costs for the Residential classes?

A. No. For KU, the non-volumetric fixed distribution costs that are classified as customer-related are $21.47 per customer per month. For LGE, the non-volumetric fixed distribution costs that are classified as customer-related are $19.34 per customer per month. The proposed basic service charge of $18.00 per customer per month for both

11 Chernick Direct Testimony, Case No. 2014-00371, 13: 4-15 and Case No. 2014-00372, 13: 7-21where he states that "Once revenue requirements are determined and allocated to classes, the considerations in designing rates are very different from those that drive class cost allocation."

Companies is a move in the direction of cost causative rates, but it does not cover all of the non-volumetric fixed distribution costs that are classified as customer-related.

Q. Do you agree with Mr. Chernick that while it may be reasonable to classify certain load-related costs as customer-related for cost allocation purposes, it does not follow that all such costs should be recovered through a fixed basic service charge?

A. No. Apparently without regard for longstanding Commission precedent, Mr. Chernick states in his Direct Testimony and his responses to the Companies' data requests that, although a utility's cost of service is useful to allocate revenue requirements equitably among rate classes, it is driving customers' behavior that should guide ratemaking.[12] But as Mr. Chernick admits in his responses to the Companies' data requests, he is not aware of any Commission orders explicitly stating that driving customers' behavior should guide ratemaking;[13] I am similarly unaware of any such orders. Instead, in Administrative Case No. 203, the Commission stated, "[T]he cost of service standard of Section 111(d)(l) of PURPA [the federal Public Utilities Regulatory Policy Act of 1978] … [is] the key standard and should be considered separately from the other ratemaking standards."[14] The other ratemaking standards the Commission cited were conservation, utility efficiency, equitable rates, rate continuity, revenue stability, and

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12 Chernick KU Testimony at 13; Chernick LG&E Testimony at 13; Responses to KU Data Requests on Behalf of Sierra Club, Response to DR No. 1; Responses to LG&E Data Requests on Behalf of Sierra Club, Response to DR No. 1.

13 Responses to KU Data Requests on Behalf of Sierra Club, Response to DR No. 1; Responses to LG&E Data Requests on Behalf of Sierra Club, Response to DR No. 1.

14 *In the Matter of: The Determinations with Respect to the Ratemaking Standards Identified in Section 111(d)(1)-(6) of the Public Utility Regulatory Policies Act of 1978*, Administrative Case No. 203, Order at 4 (Feb. 28, 1982).

rate understandability.[15] Of those ratemaking standards, the only one the Commission described as "key" was the cost-of-service standard, which stated:

> Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class ….
>
> …
>
> [T]he costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the state regulatory authority. … Such methods shall to the maximum extent practicable - (1) permit identification of differences in cost incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and (2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such state regulatory authority or non-regulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if - (a) additional capacity is added to meet peak demand relative to base demand; and (b) additional kilowatt-hours of electric energy are delivered to electric consumers.[16]

The Commission stated concerning the record of Administrative Case No. 203 on the cost-of-service standard, "One of the <u>least</u> disputed propositions advanced during the cost of service hearings was that the conservation, efficiency, and equity purposes of PURPA, as well as the additional objectives of the Commission—adequacy and stability of revenue for the utilities, minimization of economic dislocations from rate changes, acceptance and understanding of rate structures by consumers—are best

15 *See id.* at 4-9.
16 *Id.* at 10.

served by rates that track costs."[17] Concerning the conservation standard, the Commission did not advocate for crafting rates to achieve maximum encouragement of conservation regardless of a utility's cost of service, but rather stated, "Prices which reflect the cost of the resources necessary to produce an additional unit of electricity will encourage conservation."[18] Finally, the Commission stated that, *contra* Mr. Chernick, equity is an important consideration in making rates, not just revenue allocation:

EQUITABLE RATES

> This purpose envisions the promotion of equitable rates for consumers of electricity. <u>The Commission believes that rates based on costs will achieve this purpose</u>, and that payment for the cost consequences of consumption decisions avoids wasteful subsidies among consumers. However, this purpose is not to be construed as requiring equal rates of return among classes of consumers.[19]

So what is clear from the Commission's precedent is that a utility's cost of service is to have paramount sway not just in revenue allocation, but also in rate design. This is fully consistent with the Commission's orders in the Companies' 2012 base-rate cases that Mr. Chernick quotes, "[W]e will strive to avoid taking actions that might disincent energy efficiency";[20] certainly the Commission should not approve rates that

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17 *Id.* at 17-18 (emphasis in original).
18 *Id.* at 7.
19 *Id.* at 8 (emphasis added).
20 Chernick KU Testimony at 4, *quoting In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Order at 11 (Dec. 20, 2012); Chernick LG&E Testimony at 4, *quoting In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at 15 (Dec. 20, 2012).

are detrimental to energy-efficiency incentives if the rates have no cost-of-service basis. This is also consistent with the Commission's statement in a 2009 order, "[T]he Commission is very much interested in cost-of-service-based rates and demand-side management programs that incentivize both the utility and customers to practice energy efficiency in a cost-effective manner."[21]

What is further clear is that the Companies' proposed residential Basic Service Charges advance what the Commission has called the key consideration in designing rates; they are closer to the total customer-related costs shown in the Companies' cost-of-service studies. As I noted above, achieving this move toward the Commission's key rate-design objective will have no material effect on customers' energy-efficiency incentives, but it will also advance the Commission's equity goals by reducing intra-class subsidy between high-usage and low-usage residential customers. This advancing of the Commission's interest in equitable rates with no material effect on conservation incentives accords with the Commission's statement in Administrative Case No. 203 concerning its six non-cost-of-service ratemaking objectives: "It is not necessary that in every instance all of the purposes be achieved. It is sufficient if any objective is achieved and none is adversely affected."[22] The Companies' proposed residential Basic Service Charges meet these objectives.

Q. Are the Companies' proposed residential Basic Service Charges consistent with

21 *In the Matter of: General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.*, Case No. 2008-00409, Order at 6 (Mar. 31, 2009).
22 *Id.* at 7.

the marginal-cost considerations you quoted above from Administrative Case No. 203?

A. Yes. The marginal-cost-related rate considerations the Commission quoted from PURPA address take into effect how "total costs to an electric utility are likely to change if - (a) additional capacity is added to meet peak demand relative to base demand; and (b) additional kilowatt-hours of electric energy are delivered to electric consumers."[23] In other words, they are demand- and energy-related considerations, not customer-related distribution costs. The basic service charges recover customer-related distribution costs for both Companies and are not based on any transmission, generation, or demand-related distribution costs; those costs are reflected in the proposed residential energy charges. Therefore, the Companies' proposed residential electric Basic Service Charge is fully consistent with the marginal-cost-related considerations the Commission addressed in Administrative Case No. 203.

<u>Proposed Residential Time-of-Day Rates</u>

Q. Do you agree with Mr. Chernick's recommendation that the time-of-day energy rate should be modified to include April and October in the summer period?

A. No. KU and LGE proposed using the same definitions of the summer periods that are used in existing rates that have previously been approved by the Commission (see KU Power Service Tariff, Sheet No. 15, LGE Power Service Tariff, Sheet No. 15). If the Companies changed the definition of the summer periods in the residential time of day

23 *Id.* at 10.

tariffs that they are proposing, for the sake of consistency, they would need to change the definition of the summer periods in their other tariffs, which the Companies are not proposing to do at this time.

Q. Do you agree with Mr. Chernick's recommendation that the winter evening should be included in the winter peak period and the differentials between the peak and off-peak rates should be reduced?

A. No. Mr. Chernick based his recommendation that the winter evening should be included in the winter peak period on the observation that winter months have a secondary peak in the evening that is lower than the morning peak, and his claim that strong price signals that shift load off the morning peak may create a new evening peak.[24] The Companies wanted to keep the winter peak period as narrow as possible and do not believe that there is much opportunity to shift load from the morning peak period to the evening. Mr. Chernick's response regarding loads that could be shifted from the morning peak to the evening peak demonstrates little potential for such a significant shift from morning to evening peak periods.[25] Furthermore, increasing the size of the peak period would make the time of day rate less useful to residential customers and would reduce the magnitude of the financial benefit from shifting load to the off-peak period. Both of these impacts would likely reduce the number of

24 Chernick Direct Testimony, Case No. 2014-00371, 27:10-13 and , Case No. 2014-00372, 27:12 through 28:2
25 Sierra Club response to LGE 3 which states that "The loads that might most commonly be shifted would be laundry (clothes washing and associated water-heating load, clothes drying) and dishwashing (whether by hand or in a dishwasher, including the associated water-heating load). Other loads that might be shifted would include other hot-water uses (e.g., when the floor is washed, or the dog gets its bath), some cooking (e.g., the choice between using a slow cooker all day or a pressure cooker in the evening to make dinner), and specialized uses (e.g., a pottery kiln)."

customers who may want to volunteer to take service under the time of day rate. Mr. Chernick justifies his recommendation to reduce the differential between on-peak and off-peak prices on a concern that "dramatically flattening the rate differentials in the future may disrupt industries (rooftop solar, electric vehicle sales and service) that develop on the basis of the Company's exaggerated incentives."[26] When asked whether reducing the differential between on-peak and off-peak energy charges would reduce the financial incentive to shift load to off-peak periods, Mr. Chernick responded in the affirmative but qualified his affirmative response stating:

> Reducing that differential could be beneficial in that offering inappropriately large discounts for using energy outside of the peak pricing period will tend to excessively reward customers who already use energy primarily outside that period or who shift load out of the peak pricing period, excessively penalize customers who shift load into the peak period, and encourage inefficient investments (of capital, time, increased total energy use, effort, inconvenience and discomfort) to shift load, potentially spending much more to shift than the shift would save. (Sierra Club Response to Data Request LGE-5)

Mr. Chernick's response is premised on the on-peak/off-peak differentials being "inappropriately large discounts." However, the on-peak/off-peak differentials developed by the Companies are based on the costs of serving in each of these periods as developed from the cost of service study. Mr. Chernick's concern that the on-peak/off-peak differentials are "inappropriately large discounts" is speculative and is not based on the cost of offering time of day rates using the peak periods that the Companies have proposed. The Companies' proposed rates are based on the cost of

26 Chernick Direct Testimony, Case No. 2014-00371, 40:23 through 41:3 and Case No. 2014-00372, 41:2-4

offering time of day rates using the peak periods that the Companies have proposed and should be accepted by the Commission.

Q. Do you agree with Mr. Chernick's recommendation that the Commission reject the Company's proposed time of day rate that includes a demand charge?

A. No. The residential time of day rate that includes a demand charge is voluntary and is a more accurate way of recovering the cost of serving a customer than a flat kWh charge. The time of day rate that includes a demand charge would give customers more control over their energy bills than a flat energy charge. With a flat kWh charge, the only way customers can reduce their energy bills is to reduce kWh consumption. With a demand charge, customers can reduce their energy bills by flattening their usage while consuming the same amount of energy, which typically makes them less costly to serve. In the cost of service study, generation and transmission costs are allocated using a base, intermediate and peak allocator, while demand-related distribution costs are allocated using non-coincident peak demand. Non-coincident peak demand is measured by the customer's maximum usage during the month and reflects the fact that utilities must engineer their system by installing equipment of sufficient size to meet a customer's maximum usage. A demand charge is used to reflect the cost of the equipment necessary to meet a customer's maximum usage and provides an incentive for the customer to use the utility's equipment efficiently. Mr. Chernick states that "demand charges do not reflect the variation in marginal energy costs or in market prices."[27] Although Mr. Chernick has identified a couple of the things that demand charges do not cover, he provided no useful information to the Commission about what they do cover. Demand charges are used to recover capacity costs, not energy costs or market prices for electric energy.

With the cost of installing a kW of equipment dwarfing the fuel cost of producing an additional kWh, it is important to both Companies and to customers to provide a price signal and an incentive to conserve capacity and to use the Companies' capacity efficiently. A demand charge provides a price signal and an incentive to conserve capacity and to use the Companies' capacity efficiently. An incentive to conserve energy is provided by the kWh charge which reflects the fuel, scrubber reactant and variable O&M costs of producing an additional kWh. Thus, a rate that includes both a demand charge and an energy charge provides a signal to use both capacity and energy efficiently. If a demand charge is not included in the rate and the fixed cost of the equipment needed to meet a customer's maximum usage is recovered using a kWh charge, there is a strong signal to conserve energy but no incentive to conserve capacity, which is considerably more expensive. Mr. Chernick focuses on sending price signals to conserve energy with no regard for providing incentives to use capacity efficiently. The time of day rate that includes a demand charge accurately reflects the cost of serving customers, and it should be the customers' choice whether they take service under this rate alternative. I see no benefit to customers from taking

27 Chernick Direct Testimony, Case No. 2014-00371, 23:20-21 and Case No. 2014-00372, 23:20-21

this voluntary rate option away from customers and recommend that the Commission ignore Mr. Chernick's recommendation for the Commission to reject the Company's proposed time of day rate that includes a demand charge.

Q. Do you agree with Mr. Chernick that a cost of service study is not designed to estimate the incremental costs of serving an additional kWh on-peak versus off-peak?

A. Yes, but he is inconsistent in how he applies this observation. Mr. Chernick states that "(t)he COSS is not designed to estimate the incremental costs of serving an additional kilowatt-hour on peak versus off-peak."[28] A cost of service study allocates the utility's total cost of serving customers to the various rate classes that the utility serves using allocators based on different cost drivers that reflect various measures of customer usage. However, after recognizing that a cost of service study is not useful for estimating incremental costs, Mr. Chernick uses the cost of service study that I developed to estimate the incremental cost of serving a new customer.[29] The rates developed from a cost of service study reflect the average cost of providing either capacity or energy to customers. Pricing a service using marginal cost typically ignores fixed cost recovery, which is vitally important with the magnitude of fixed costs that are typical in the electric utility industry. Mr. Chernick's discussions of marginal concepts are not useful for the Commission in determining whether the rates proposed

28 Chernick Direct testimony, Case No. 2014-00371, 39:16-18 and Case No. 2014-00372, 39:16-18

29 Chernick Direct testimony, Case No. 2014-00371, 11:18 through 12:7 and Case No. 2014-00372, 11:21 through 12:8

by the Company are just and reasonable, and his recommendations should be ignored by the Commission.

<u>Cost of Service Study Matters</u>

Q. Should the Commission adopt Mr. Baron's suggestion to reject the use of the modified Base-Intermediate-Peak ("BIP") methodology that you used to develop the cost of service studies in this proceeding?[30]

A. No. The use of the modified BIP in developing the cost of service studies in this proceeding is consistent with the Companies' four most recent base-rate cases, and is a methodology the Commission first approved for LG&E in 1990 while rejecting a KIUC-proposed cost-of-service-study alternative.

Q. Do you agree with Mr. Baron's corrections to the cost of service study that you developed in this proceeding?

A. Yes. Mr. Baron pointed out that there should be no allocation of distribution facilities to the RTS class and that metered hourly loads were not adjusted for losses in the development of the demand allocation factors.[31] Both of these changes are consistent with cost of service studies filed in previous rate cases filed by the Company and should be made to the cost of service study that I developed in this proceeding. However, making these changes would not change the Company's proposed rate design that utilizes a uniform percentage increase for each class of customers, which Mr. Baron

30 Baron Testimony at 9-11.
31 Baron Direct Testimony, 5:4-11

supports.[32]

Merging LG&E Electric Rates CTODP and ITODP

Q. Do you agree with Mr. Baron's recommendation not to merge LGE Rates CTODP and ITODP in this proceeding?

A. No. Mr. Baron admits that he does not oppose the merger of LGE Rates ITODP and CTODP conceptually but opposes this merger because it is not consistent with gradualism. In my opinion, this is exactly the right time to merge these two rate classes. With a uniform increase of 2.73% for all LGE rate classes, the impact of merging these two rates at this time is likely to be smaller than it would be in a future rate case where the overall rate increase might be larger. Additionally, merging these two rates would be consistent with the rates that KU offers.

Kentucky School Board Association Matters

Q. Do you agree with Mr. Willhite that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges violates the principles of gradualism?

A. No. I disagree with Mr. Willhite's statement that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges violates the principles of gradualism.[33] When gradualism is considered in designing rates, it is typically applied to the overall increase assigned to a rate class and not to the change in individual rate components. The rate increases assigned to Rates PS-Sec and TODS are the same as

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32 Baron Direct Testimony, 20:3-8
33 Willhite Testimony, Case No. 2014-00371, 3:25-30 and Case No. 2014-00372, 3:26-29

the increases assigned to other rate classes and are consistent with the concept of gradualism. KU found that if rates of return on rate base among rate classes were reduced, as Mr. Willhite recommends, the rate increase to some rate classes would be more than 20%, which the Companies believed raised concerns about gradualism. Thus, the Companies' proposed rate design that assigns uniform increases to each rate class is consistent with the concept of gradualism rather than violating the concept of gradualism as Mr. Willhite claims. In fact, reducing the differences in the rates of return among the rate classes as Mr. Willhite suggests is more likely to violate the concept of gradualism than the Companies' proposed rate designs.[34]

Q. Do differences in the energy bills for individual schools served under Rates PS-Sec and TODS from the class average show that the proposed rates are inconsistent with gradualism?

A. No. Mr. Willhite also regards an energy bill increase to some schools being larger than the class average as an indication that the proposed rates are not consistent with the concept of gradualism for both KU and LGE.[35] But Mr. Willhite's claim is another misapplication of the concept of gradualism. By the way they are calculated, rates are averages with some entities receiving an energy bill larger than the class average and some receiving an energy bill below the class average based on the usage patterns of individual customers within the class. If some schools have an energy bill above the class average percentage increase, there are other schools with an energy bill below the

34 Willhite Testimony, Case No. 2014-00371, 10:1-2 and Case No. 2014-00372, 9:45-46
35 Willhite Testimony, Case No. 2014-00371, 10:4-10 and Case No. 2014-00372, 10:1-7

class average percentage increase. These differences are a result of energy usage patterns that deviate from the class average and are an indication that different usage levels and patterns result in different costs being incurred by the Companies and not an indication of the rate increases to Rates PS-Sec and TODS being inconsistent with the concept of gradualism as Mr. Willhite claims. For both Companies, the rate increases for Rates PS-Sec and TODS are the same as the rate increases for the Companies' other rate classes, which is consistent with the concept of gradualism.

Q. Do you agree with Mr. Willhite that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges is contradictory to sound cost of service principles?

A. No. I disagree with Mr. Willhite's statement that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges is contradictory to sound cost of service principles.[36] The costs that the Companies propose to recover using demand charges are demand-related fixed generation, transmission and distribution costs that were allocated to Rates PS-Sec and TODS. Recovering these demand related costs using demand charges is totally consistent with the sound ratemaking principle of recovering fixed costs through fixed charges and variable costs through variable charges. In fact, recovering these demand-related fixed costs through an energy charge as Mr. Willhite suggests would violate this ratemaking principle by recovering a fixed cost using a variable charge assessed on a kWh basis.

36 Willhite Testimony, Case No. 2014-00371, 3:27-30 and Case No. 2014-00372, 3:26-29

Q. Do you agree with Mr. Willhite that the schools served under Rates PS-Sec and TODS are subject to an unreasonable disadvantage?

A. No. Mr. Willhite claims that the schools served under Rates PS-Sec and TODS are subject to an unreasonable disadvantage because they have different load characteristics than industrial and commercial customers served on those rates.[37] Mr. Willhite bases this conclusion on a comparison of load shapes for schools, commercial customers and industrial customers for the months of July and August in Exhibits RLW-2 and RLW-3. He does not examine the relative load shapes for the months of December, January and February when the Companies typically experience winter peaks and when Mr. Willhite admits that the load shape for schools is likely to be coincident with the Companies' winter system peaks.[38] He also does not examine the relative load shapes for the shoulder months of September, October, November, March, April and May. Although the summer peak is used for planning system resources, the Companies have experienced annual peaks during the winter months several times since the year 2000, and it is necessary to consider the impact of Rates PS-Sec and TODS in the winter months, when school load shapes are likely to coincide with the Companies' system peaks, and during the shoulder months to determine whether the proposed rates are unreasonable. Mr. Willhite's analysis is very selective and only examines the load shapes in two months. Furthermore, Mr. Willhite admits that schools

37 Willhite Testimony, Case No. 2014-00371, 10:43 through 11:8 and Case No. 2014-00372, 10:38 through 11:3
38 Willhite Testimony, Case No. 2014-00371, 10:35-36 and Case No. 2014-00372, 10:29-30

typically have lower load factors than other customers served in these rate classes, which typically makes them more expensive to serve because the resources installed to serve them are used on a more sporadic basis.[39] He has not demonstrated that the proposed rates are unreasonable when applied to entities taking service under Rates PS-Sec and TODS for an entire year.

Q. Did Mr. Willhite support his recommendation that separate rate classes for schools be added and that the demand charges for these rates be set at some percentage of the demand components for Rates PS-Sec and TODS?

A. Mr. Willhite recommends that the Company be directed to add Rates PS-School and TOD-School to its tariff and that the demand charges be set at no greater than 75% of the PS and TODS demand charges for KU and no greater than 85% of the PS and TODS demand charges for LGE.[40] As noted above, Mr. Willhite's recommendation to establish separate rate classes for schools is based on a very selective analysis of load shapes in only two months. Even for his analysis of the two months included in Exhibits RLW-2 and RLW-3, he has not shown that the load shapes for schools deviate from the class average by an amount that would justify the formation of separate rate classes for schools. Additionally, there is no evidentiary support for Mr. Willhite's recommendation that the demand charges for schools be set at no more than 75% of the demand components for Rates PS and TODS for KU and 85% of the demand

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39 KSBA Response to LGE 5d which states that "Mr. Willhite has observed that annual school load factors range from 25 to 45 percent with elementary schools at the lower end of the range and high schools at the higher end. Non-school loads such as industries and businesses typically have much higher load factors."
40 Willhite Testimony, Case No. 2014-00371, 11:13-15 and Case No. 2014-00372, 11:4-9

components for Rates PS and TODS for LGE. Lacking evidentiary support, Mr. Willhite's recommendation to establish separate rate classes for schools should be disregarded by the Commission. Even if the Commission were to order the formation of separate rate classes for schools, Mr. Willhite's recommendation on the appropriate level of the demand charge totally lacks evidentiary support and could not be used by the Commission in establishing rates for these new rate classes.

Q. Do you agree with Mr. Willhite's recommendation to unfreeze Rate AES?

A. No. Mr. Willhite recommends that the Commission unfreeze Rate AES for KU and order LGE to develop a Rate AES for schools.[41] Rate AES does not contain a demand charge component, without which it is not possible to accurately charge for the demand-related fixed generation, transmission and distribution costs that service to schools with differing load characteristics impose on KU. As noted earlier, a demand charge component is the most accurate method of charging for these demand-related costs and requiring schools to take service under Rates PS and TOD would help to correct this problem. Mr. Willhite's recommendation to unfreeze Rate AES for KU and to order LGE to develop a Rate AES is inconsistent with his recommendation to add Rates PS-School and TOD-School that contain demand rates, as this recommendation recognizes the importance of demand charges in accurately billing schools.[42] Mr. Willhite's statement that the lack of a demand charge in Rate AES "simply means there is intra-class cross-subsidization among the school accounts" does not provide the

41 Willhite Testimony, Case No. 2014-00371, 12: 24-27 and Case No. 2014-00372, 11:43-46
42 Willhite Testimony, Case No. 2014-00371, 12: 40-46

Commission with sufficient justification to adopt Mr. Willhite's recommendation to unfreeze rate AES for KU and to order LGE to develop a Rate AES.[43]

Q. Do you agree with Mr. Willhite's recommendation regarding sport field lighting?

A. No. Mr. Willhite recommends that sports fields be billed under a rate that contains only an energy charge with no demand charge. Because they have a low load factor and their usage is sporadic, it is difficult, if not impossible, to recover the significant demand-related generation, transmission and distribution costs associated with serving sports fields using only an energy charge with no demand charge. The use of a demand charge in billing these loads makes it possible to recover the significant demand-related generation, transmission and distribution costs associated with serving sports fields so that these costs are not shifted to other customers for recovery. The magnitude of the increase for sports field lighting energy bills provided by Mr. Willhite gives some indication of the subsidy that these loads were receiving when being billed on an energy-only basis.[44] Rather than indicating a problem of being unreasonably treated when billed using a demand charge, the 400% to 500% increases that Mr. Willhite cited show just how much demand charges are needed in billing these loads and indicate the magnitude of the subsidy that they have been receiving from other customers when billed using an energy-only rate. Mr. Willhite has not provided cost support for his recommendation that sports fields be billed using an energy-only rate. Lacking evidentiary support, there is no basis for the Commission to order the development of

43 Willhite Testimony, Case No. 2014-00371, 12: 34-36
44 Willhite Testimony, Case No. 2014-00371, 13: 12-13

a sport field rate rider as recommended by Mr. Willhite.

Revenue Allocation

Q. Do you agree with the proposal to reduce subsidies among classes that Mr. Chriss suggests?

A. My interpretation of the proposal described in Mr. Chriss' Direct Testimony regarding the KU rate design is to use any reduction in the revenue requirement to reduce the subsidies among the Company's customer classes.[45] With regard to the rate design proposed by KU, Mr. Chriss stated that he does not oppose the Company's proposed rate design at the level of the Company's proposed revenue requirement.[46] However, he suggests using any reduction in the revenue requirement proposed by the Company to reduce subsidies among classes while capping the increase to any rate class for KU at 9.6%. The use of any reduction in the revenue requirement to reduce subsidies among classes while capping the increase to any rate class at 9.6% for KU is acceptable to the Company as it would avoid significant increases to any single rate class. However, the methodology that Mr. Chriss suggests for accomplishing this is not clear, particularly the first two steps.[47] The first step could be interpreted several ways. First, it could mean that 25% of any revenue reduction would be allocated to reducing the subsidies among rate classes, but then it is not clear how this would be allocated "to the revenue requirement for each rate class."[48] Would some of the reduction be allocated to classes

45 Chriss Direct testimony, Case No. 2014-00371, 14:6 through 18:7
46 Chriss Direct testimony, Case No. 2014-00371, 14:6-8
47 Chriss Direct testimony, Case No. 2014-00371, 17:17 through 18:7
48 Chriss Direct testimony, Case No. 2014-00371, 17: 20-22

that were already receiving a subsidy, which step 2 seems to imply, or to only those classes that were below the average rate of return for all rate classes? Mr. Chriss' proposed methodology is confusing and requires the exercise of discretion by the Commission. The Company agrees with use of any reduction in the Company's revenue requirement to reduce subsidies among classes while capping the increase to any rate class at 9.6%, but takes no position on how this is accomplished. Because it does not understand the methodology that Mr. Chriss is proposing, the Company does not support Mr. Chriss' proposed methodology.

With regard to the rate design proposed by LGE, Mr. Chriss recommended that any increase in revenue requirements be allocated among classes in a way that would reduce the differences in rates of return among customer classes.[49] Mr. Chriss' proposed methodology is confusing and requires the exercise of discretion by the Commission. Because it does not understand the methodology that Mr. Chriss is proposing, the Company does not support Mr. Chriss' proposed methodology.

Rate CTAC Pole-Attachment Charges

Q. Did KU and LGE propose any changes to its cable television attachment charges in these proceedings?

A. No. Neither KU nor LGE proposed changes to their cable television attachment charges in these rate case proceedings. KU and LGE provided evidence in Case Nos. 2012-00221

49 Chriss Direct testimony, Case No. 2014-00372, 15:4-16

and 2012-00222 to support the cable television attachment charges. After an evidentiary hearing considering a settlement agreement, the Companies' cable television attachment charges were found to be fair, just and reasonable and approved by the Commission in an order dated December 20, 2012. In direct testimony filed by Ms. Kravtin in these proceedings, the KCTA has proposed new cable television attachment charges. Therefore, the burden of proof falls on the KCTA to demonstrate that its proposed attachment charges in this proceeding are fair, just and reasonable and that the charges approved by the Commission in Case Nos. 2012-00221 and 2012-00222 are not fair, just and reasonable.

Q. Has the KCTA met its burden of proof by demonstrating that its proposed cable television attachment charges are fair, just and reasonable?

A. No. The cost support submitted by Ms. Kravtin contains numerous errors and aggressively removes costs that should be included in the Companies' cable television attachment charges. In fact, there are mistakes in almost every part of her carrying charge calculations. In addition to all of the errors in her calculations, Ms. Kravtin disregards the fact that KU and LGE filed proposed rates based on a fully-forecasted test year in these proceedings. *All* of the rates and charges proposed by KU and LGE in these proceedings are based on forecasted costs. Ms. Kravtin completely ignored the Companies' forecasted rate filing and used historical costs to develop her proposed rates, even though she had an opportunity in discovery to obtain the forecasted data that she would have needed. This forecasted data necessary to calculate attachment charges was not filed with the other cost of service and rate design material because the Companies proposed no changes to attachment charges in these proceedings. Because Ms. Kravtin's calculations are based on historic rather than forecasted data, her proposed rates would be fundamentally inconsistent with all other rates determined in these proceedings. Thus, the cable television attachment charges proposed by KCTA should be disregarded and the Companies' current cable television attachment charges, as approved by the Commission in Case Nos. 2012-00221 and 2012-00222, should be allowed to remain in effect.

Q. Despite the fact that KU and LGE filed fully forecasted rate cases, can the reasonableness of the current rates be supported by current cost data?

A. Yes. Although KU and LGE did not propose changes to their cable television charges in these proceedings, the reasonableness of the rate can be confirmed by updating the carrying charge calculations used to support the pole attachment charges found reasonable by the Commission in the Companies' last rate case proceedings. In Rebuttal Exhibits MJB- 1 and MJB- 2, I have calculated the pole attachment charges using historical cost data for KU and LGE for the 12 months ended October 31, 2014. In these exhibits, the pole attachment charges are calculated using the same methodology used by KU and LGE to support its current cable television rates that were found fair, just and reasonable by the Commission in the Companies' last rate cases. Table 1 compares the current charges to the cost-based charges using current data for KU and LGE as calculated in Rebuttal Exhibits MJB- 1 and MJB- 2:

Table 1		
Company	Current Charges	Charges Updated for Current Cost Data
Kentucky Utilities	$ 9.69	$ 10.58
Louisville Gas and Electric	$ 9.11	$ 11.08

As can be seen from this table, the charges updated for current cost data would be higher than the current charges. As noted earlier, KU and LGE filed a forecasted test year in these proceedings. The above charges are based on historical costs for the 12 months period ended October 31, 2014, and charges based on forecasted costs would likely be higher.

Q. Do you agree with the regulatory principles that Ms. Kravtin claims should guide pole attachment regulation?

A. No. In her direct testimony, Ms. Kravtin makes the following statement:

> The primary purpose of pole rate regulation historically has been, and continues to be, about protecting cable operators and other third-party attachers against monopoly abuses of pole-owning utilities. (Case No. 2014-00371, Direct Testimony of Patricia D. Kravtin, p. 9 and Case No. 2014-00372, p. 10.)

Frankly, as a former regulator I am concerned about the suggestion that the "primary purpose" of pole attachment regulation is to look out for the interests of cable television companies and other attachers over and above the interests of a utility's other ratepayers.

The Commission should be wary of any recommendations that are based on this stated goal. The purpose of rate regulation, including the regulation of pole attachment charges, is to develop fair, just and reasonable charges for all customers taking service from the utility. By developing fair, just and reasonable rates, regulatory commissions balance the interests of ***all*** ratepayers and the utility, not just protecting the interests of cable television companies.

Q. Will lower cable television attachment charges result in lower revenue requirements to KU and LGE in these proceedings?

A. No. KU and LGE are not enriched by cable television attachments charges, regardless of the level at which these charges are set. Any reduction in cable television revenues through the determination of lower pole attachment rates will only serve to increase the rates to other customers. If the Commission determines that lower rates are warranted, then miscellaneous revenues in these proceedings will be reduced and any deficiency created by such reduction will simply be collected from other customers. This underscores the fact that KU and LGE's only objective here is to allocate the revenue increase in these proceedings in such a way that the resultant charges are fair, just and reasonable to all customers.

Q. What errors were made in the calculation of the attachment charges proposed by Ms. Kravtin?

A. Although her calculations are riddled with mistakes, she has made a serious mathematical error in her carrying charge calculations that significantly understates the annual cost for pole attachments. Specifically, contrary to standard ratemaking practice, Ms. Kravtin uses a return on net plant investment in conjunction with a sinking fund depreciation factor. Ms. Kravtin's approach is not only nonstandard, it is also fundamentally flawed.

Q. Net plant is used to calculate both rate base and revenue requirements in a rate case proceeding. Why is the use sinking fund depreciation in conjunction with a rate of return on net plant investment incorrect?

A. In a rate case, the component of the revenue requirement for recovering the return on investment is determined by applying a rate of return to net plant investment, and straight-line depreciation is used to determine the depreciation component of the revenue requirement, not sinking fund depreciation. Using sinking fund depreciation in conjunction with a rate of return on net investment significantly understates the appropriate level of revenue requirements.

It is a fundamental principle in calculating carrying charges, a subject that frequently arises in proceedings before the Federal Energy Regulatory Commission ("FERC"), that either (1) ***straight-line depreciation*** can be used in conjunction with a rate of return on ***net plant investment***, or (2) ***sinking fund depreciation*** can be used in conjunction with ***gross plant investment***. The FERC will allow either approach, as long as the utility doesn't switch back and forth between the two methodologies. Ms. Kravtin has cobbled together a nonstandard and inconsistent approach that uses the elements from these two accepted methodologies in order to produce a lower charge for pole attachments. Specifically, her approach combines **sinking fund depreciation** with a return on **net plant investment**. By combining sinking fund depreciation with net plant investment, she has chosen the lower of the two depreciation measures in combination with the lower of the two measures of return on investment.

Q. What's wrong with using a sinking fund factor with net plant?

A. Using a sinking fund factor in conjunction with calculating the return on the basis of net plant violates the principle of ***economic equivalency***.

Q. What is economic equivalency?

A. Calculations in finance and engineering economics are grounded on the principle that two or more cash flows, revenue requirements, financial alternatives, etc. can be placed on an equivalent basis for comparison by properly considering the effect of the time value of money. The principle of economic equivalency is what allows a bank to loan someone money to purchase a home in exchange for a payment stream from the borrower over the life of the mortgage. Loan payments, annuities, and carrying charge calculations are based on the principle of economic equivalency that permits a future series of payments to be considered equivalent to a present value amount by using a consistent discount rate. A fundamental aspect of economic equivalency is that if two or more payment streams are being evaluated, the same discount rate must be used in the evaluation of each stream. The concept of economic equivalency is discussed in practically every economic engineering or finance textbook. For example, see H.G. Thuesen, W.J. Fabrychy, and G. J. Thuesen, *Engineering Economy*, Fifth Edition, Chapter 5 and Chan S. Park, *Contemporary Engineering Economics*, Chapter 3. In the second text, Park writes:

> The equivalence between two cash flows is a function of the magnitude and timing of individual cash flows and the interest rate or rates that operate on those cash flows. This principle is easy to grasp in relation to

> our simple example: $1,000 received now is equivalent to $1,762.34 received five years from now only at a 12% interest rate. *Any change in the interest rate will destroy the equivalence between the two sums*, as we will demonstrate in Example 3.5. (Id. at p. 68. Emphasis supplied.)

This makes it clear that economic equivalency cannot be established unless consistent discount rates are used in the analysis.

Q. Please explain what you mean by a discount rate.

A. A discount rate is the rate used to calculate present value or future value factors in economic studies and comparisons. The discount rate represents a company's opportunity cost or weighted cost of capital. It is therefore the rate used in present or future value calculations that allows a payment received or an outlay made at one point in time to be compared on a consistent basis to a payment or outlay at another point in time. Thus, by using a consistent discount rate reflecting a company's opportunity cost, one series of payments can be compared to another series of payments on a present value basis. If the present values of two different payment streams are calculated using different discount rates, then fundamentally they are not equivalent. In evaluating two or more payment streams, it is necessary to use the same discount rates in calculating the present value of the payment streams.

Q. Can you provide simple examples demonstrating the concept of *economic equivalency*?

A. Yes. Suppose that a present value of a lump-sum amount is $1,000. It can be demonstrated that this present-value lump-sum amount is equivalent to the following two five-year payment streams using a 10% discount rate (rate of return): (1) an annual payment amount determined by applying the rate of return to net investment and then adding straight-line depreciation, and (2) an annual payment amount determined by applying the rate of return to gross investment but then adding sinking fund depreciation.

The mathematical and economic equivalency of these two payment streams can be seen from the following tables. Table 2 shows the present value of payment stream by calculating the annual payments based on the return on net investment plus straight line depreciation.

Table 2

Year	Gross Investment	Straight Line Depreciation	Net Investment	Return @10%	Payment Amount	Present Value @10%
1	$ 1,000	$ 200	$ 1,000	$ 100	$ 300	$ 273
2	1,000	200	800	80	280	231
3	1,000	200	600	60	260	195
4	1,000	200	400	40	240	164
5	1,000	200	200	20	220	137
						$ 1,000

As can be seen from Table 2, when using a 10% discount rate, the sum of the present value annual payments is mathematically equal to the original $1,000 investment. Consequently, this payment stream calculated using straight line depreciation and return on net investment is economically equivalent to the $1,000 original cost investment.

Table 3 shows the present value of the payment stream by calculating the annual payments based on the return on gross investment plus sinking fund depreciation.

Table 3					
		Sinking			Present
	Gross	Fund	Return	Payment	Value
Year	Investment	Depreciation	@10%	Amount	@10%
1	$ 1,000	$ 164	$ 100	$ 264	$ 240
2	1,000	164	100	264	218
3	1,000	164	100	264	198
4	1,000	164	100	264	180
5	1,000	164	100	264	164
					$ 1,000

As can be seen from Table 3, when using a 10% discount rate, the sum of the present value annual payments is mathematically equal to the original $1,000 investment. When using sinking fund depreciation in conjunction with return on gross investment, the resulting payment stream is economically equivalent to the $1,000 original cost investment. Therefore, the present value of a stream of annual payments calculated using a 10% rate of return on net investment plus straight-line depreciation is mathematically and economically equivalent to a stream of annual payments calculated using a 10% rate of return on gross investment plus sinking-fund depreciation.

Economic equivalency is the principle that makes it possible to compare the present value amount to a stream of payments. It should be emphasized that the same discount rate of 10% must be used in both present value calculations or the premise on which economic equivalency is based is violated. Using a different discount rate in the evaluation of the payment streams violates the premise on which economic equivalency is based.

Obviously, it would be possible to force the present value of practically any two payment streams to be equal by using different discount rates, but using different discount rates would not demonstrate that the two payment streams were economically equivalent. If different discount rates are used then *fundamentally* the payment streams cannot be considered equivalent. Rebuttal Exhibit MJB-3 provides an example of how Ms. Kravtin uses different discount rates to force her revenue requirement streams to be equal, which, of course, means that her calculations and conclusions are not economically equivalent and thus meaningless.

Q. How do Ms. Kravtin's carrying charge calculations violate *economic equivalency*?

A. She inappropriately uses sinking fund depreciation in conjunction with a return calculated by applying the rate of return to net investment. In the example in Table 1 above, the 10% rate of return was applied to net investment, but straight-line depreciation was used to determine the annual payments. Consequently, the present value of the payment stream is equal $1,000. In the example in Table 2, the 10% rate of return was applied to gross investment, but sinking fund depreciation was used to determine the annual payments. In both cases, the present value of the payment stream is equal to $1,000. In Ms. Kravtin's analysis, she calculates the return using net plant but inappropriately uses sinking fund depreciation, which mathematically violates economic equivalency and which violates the sound regulatory principles that are applied consistently by FERC.

Q. Can you provide a simple example showing how Ms. Kravtin's approach is mathematically incorrect?

A. Yes. Table 4 shows the effect of using net plant to calculate the return in conjunction with sinking fund depreciation.

Table 4						
		Sinking				Present
	Gross	Fund	Net	Return	Payment	Value
Year	Investment	Depreciation	Investment	@10%	Amount	@10%
1	$ 1,000	$ 164	$ 1,000	$ 100	$ 264	$ 240
2	1,000	164	800	80	244	201
3	1,000	164	600	60	224	168
4	1,000	164	400	40	204	139
5	1,000	164	200	20	184	114
						$ 863

As can be seen from Table 4, calculating carrying costs on the basis of sinking fund depreciation plus return on net investment results in a sum of present value payments of only $863. This approach does not provide for full recovery of the $1,000 original investment, and the use of this methodology by Ms. Kravtin understates the cost of and the rate that should be charged for a pole attachment.

Q. Can you demonstrate how the payment stream shown in Table 4 can be forced to produce a present value of $1,000 by forcibly manipulating the discount rate?

A. Yes. If the cost of money is 10%, then obviously the discount rate should also be 10%, but a lower discount rate can be found through the application of goal seeking tools or by other means that will artificially increase the present value of the stream of payments to equal $1,000. As can be seen from the Table 5, using a discount rate of 4.1 % instead of the 10% rate of return will produce a sum of present value payments of $1,000. Of course, the comparison is meaningless because a 4.1% discount rate was used instead of the 10% discount rate corresponding to the actual cost of money in the example. Rebuttal Exhibit MJB-3 provides an example of how Ms. Kravtin has used a different, lower discount rate to create a false impression that the use of sinking fund depreciation in conjunction with return on net plant investment is acceptable.

Table 5

Year	Gross Investment	Sinking Fund Depreciation	Net Investment	Return @10%	Payment Amount	Present Value @4.1%
1	$ 1,000	$ 164	$ 1,000	$ 100	$ 264	$ 253
2	1,000	164	800	80	244	225
3	1,000	164	600	60	224	198
4	1,000	164	400	40	204	173
5	1,000	164	200	20	184	150
						$ 1,000

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The inappropriate use of sinking fund depreciation with a return on net investment means that only a 4.1% return is actually provided by the payment stream in the example above rather than the intended rate of return of 10%.

Q. In calculating her proposed rates, where specifically does Ms. Kravtin use sinking fund depreciation in conjunction with a return on net investment?

A. Ms. Kravtin calculates her proposed attachment charges in Attachment 2 of her testimony. In the first page of her analysis (in the middle of the page) it can be seen that she uses a sinking fund depreciation factor of 1.36% for the test year calculations for KU and of

1.37% for the test year calculations for LGE, but on the same page it can be seen that she makes an adjustment to the rate of return from 7.23% to 3.10% for KU and from 7.31% to 3.95% for LGE which reflect a return on net investment, rather than the appropriate return on gross investment that is consistent with the use of sinking fund depreciation.

Q. In Attachment 3 to her direct testimony, Ms. Kravtin purports to demonstrate that her methodology is equivalent to a non-levelized approach using straight line depreciation and a return on net investment. Does her analysis truly demonstrate that the two approaches are equivalent?

A. No. Ms. Kravtin's analysis is incorrect and is based on the use of two different discount rates. Rebuttal Exhibit MJB-3 is a markup of Ms. Kravtin's Table 1 illustrating her use of a discount rate of 8.32% in the portion of the table analyzing "Non-Levelized" carrying charge calculation and use of a discount rate of only 4.16% in the portion of the table analyzing her "Levelized" carrying charge calculation. Because she used *sinking fund depreciation* in conjunction with a rate of return on *net investment*, it was necessary for her to use a lower discount rate to force the present value for her "Levelized" carrying charges to equal the "Non-Levelized" carrying charges. Specifically, Ms. Kravtin used a lower discount rate to force the present value payments to equal $1,000. However, Ms. Kravtin attempts to obscure the fact that she used a 4.16% discount rate by referring to it as a "Present Value @Gross ROR" instead of labeling is "Present Value@4.16%" as she did with the "Present Value@8.32%" in her analysis of "Non-Levelized" carrying charges (see Rebuttal Exhibit MJB- 3). Despite Ms. Kravtin's attempts at obfuscation, her analysis demonstrates that her proposed carrying charges would only provide a 4.16% return.

By providing a low rate of return for cable television pole attachment service, her charges would shift costs to other ratepayers. Specifically, by requiring cable television companies to provide a return of only 4.16%, she would force other customers to pick up the difference between the 8.32% rate of return that should be provided by cable television customers and the 4.16% they would actually provide under Ms. Kravtin's rates.

Q. What happens to her analysis if a consistent discount rate is used?

A. In Rebuttal Exhibit MJB-4, I have corrected the error made in Table 1 of Attachment 3 to Ms. Kravtin's KU and LGE testimony. As can be seen from Rebuttal Exhibit MJB-4, Ms. Kravtin's mathematically flawed carrying charge calculation, which inappropriately uses sinking fund depreciation in conjunction with a rate of return on net plant, results in a sum of present value of annual carrying charges of only $617.89 which is equivalent to only 61.80% of total costs. This suggests that Ms. Kravtin's flawed carrying charge approach would understate the actual cost of pole attachment service by 38.20% for both KU and LGE.

Q. Does your analysis demonstrate that Ms. Kravtin's proposed cable television attachment charges are significantly understated?

A. Yes.

Q. Do you agree with the way that Ms. Kravtin calculated the O&M factor in her carrying charge calculation?

A. No. Ms. Kravtin calculates the O&M factor by dividing pole-related operation and maintenance expenses by Account 364 – Poles, Account 365 – Conductors and Devices ("Conductors"), and Account 369 Services ("Services"). Ms. Kravtin specifically mentions tree-trimming expenses as an expenses item that should be spread to Conductors and Services. While it is true that tree trimming protects conductors as well as poles, she fails to consider that KU and LGE's tree-trimming efforts also help protect the lines owned by cable television companies. In calculating the carrying charges for pole attachment service, it is not possible to spread a portion of tree-trimming expenses to the cable television companies' distribution lines because their property is not included on KU and LGE's books. The only way to allocate the cost of tree-trimming to lines owned by cable television companies is to spread the costs to poles. Cable television companies are billed for attachment service solely on the basis of a pole attachment. If tree-trimming and other expenses are allocated to Conductors and Poles, as suggested by Ms. Kravtin, then the cable television companies would have to be billed for tree trimming services based on the miles of cable television line running along LGE and KU's rights of way, which is not a practical approach. The cable television charge is unitized on the basis of a pole attachment charge; therefore, the charge should include a proportionate share of tree trimming expenses which cannot be billed to the miles of cable television lines and services which KU and LGE's tree trimming activities also benefit.

Q. Do cable television companies perform any tree trimming on their own lines?

A. Not that the Companies are aware of, and definitely not in any systematic or regular manner. As far as the Companies know, the cable television companies rely exclusively on KU and LGE to provide tree trimming.

Q. Does KU or LGE perform routine tree trimming on services?

A. No. KU and LGE rarely perform tree trimming on services. Tree trimming is focused on overhead lines and not services which are located on customers' property. The fact that Ms. Kravtin fully spreads tree-trimming to Account 369 Services is another flaw in her analysis.

Q. Are there other errors in her calculations?

A. Yes, there are several others. Ms. Kravtin's carrying charge calculation for LGE uses the wrong rate of return. As shown on the second page the carrying charge calculations in Attachment 2 of her testimony, the weighted return on capital that she uses is 7.31%. The weighted rate of return should be 7.36% percent, as shown in Schedule J-1, page 2 of the filing requirements for LGE.

Q. Did Ms. Kravtin use the correct income tax rate in her carrying charge calculations?

A. No. As shown the second page of the carrying charge calculations in Attachment 2 of her testimony, Ms. Kravtin uses a composite state and federal income tax rate of 36.86% for KU and 37.52% for LGE. The composite state and federal income tax rate should be 38.90%, for both Companies as shown in the responses to Question 11 of the KCTA's First Data Requests to KU and LGE. The income tax rates used by Ms. Kravtin incorrectly include Section 199 deductions for KU and LGE. The Section 199 deduction is a tax break for businesses that perform domestic manufacturing and certain other production activities. Because electric distribution poles and pole attachments are not involved in manufacturing or production, Section 199 deductions should not be reflected in the income tax rates. Therefore, in calculating carrying charges for the cable television attachment charges, the statutory state and federal income tax rate of 38.90% must be used.

Q. Did Ms. Kravtin use the correct property tax rate in her carrying charge calculations?

A. No. Ms. Kravtin used an incorrect property tax percentage in her carrying charge calculations. Specifically, she used an effective property tax rate of 0.22% for both KU and LGE. The property tax rate should be 0.42% for KU and 1.10% for LGE, as calculated against gross plant. The rates should be 0.76% for KU and 2.03% for LGE if net plant is used instead, as proposed by Ms. Kravtin; however this would necessitate the use of straight line depreciation rather than the sinking fund depreciation that Ms. Kravtin uses in her analysis. The data necessary to calculate the effective property rates were provided in KU and LGE's responses to Question 25 to KCTA's Supplemental Data Requests.

Q. Did Ms. Kravtin use the correct amount for LGE's tree trimming expenses?

A. No Ms. Kravtin used $16,450,212 for tree trimming expenses. The amount should be $16,088,333. Of all the mistakes in Ms. Kravtin's attachment charge calculation, this is the only one that doesn't work in her client's favor.

Q. Are there problems with the labor costs used in Ms. Kravtin's carrying charge calculations?

A. Yes. She estimates labor expenses used in the calculation simply by prorating costs from the Company's previous CATV calculations. The labor expenses shown on the second page of Attachment 2 to her testimony for Accounts 593001 and 593004 simply reflect pro-rated amounts based on the amounts shown in the Companies carrying charge calculations submitted in Case Nos. 2012-00221 and 2012-00222. Ms. Kravtin seems to have made no attempt to use actual expenses.

Q. Ms. Kravtin also proposed to reduce costs for "minor appurtenances". Do you agree with this adjustment?

A. No. Ms. Kravtin proposed to adjust pole costs by 15% to eliminate "minor appurtenances." KU and LGE have no cost classification on its books for "minor appurtenances," and they do not track the types of items that Ms. Kravtin claims should be included in this cost category. In prior rate cases for both Companies, no reduction for "minor appurtenances" was used in calculating rates for cable attachments. Administrative case No. 251 is a simplified method for calculating a charge for cable attachments that does not fully allocate all of the Companies' costs, as is done in a cost of service study. Because major cost items do not enter the calculation of the charge for cable attachments, as explained more fully below, the Companies did not make a reduction for minor appurtenances considering this to be at least a wash with the other costs that were not included.

Q. Is it clear from the Commission's Order in Administrative Case No. 251 that 15% should be excluded to reflect "minor appurtenances"?

A. No. The Commission Order in Administrative Case No. 251 dated September 17, 1983, seems to suggest that 15% should be excluded from the cost of poles when Account 364 is somehow used in aggregate. Specifically, the Commission stated that "an adjustment of 15 percent subtracted from the sum of the appropriate sub-account of FERC Form 1, Account 364, and a deduction of $12.50 per ground, when such grounds are included in Account 364, will reasonable approximate the cost of an average bare wooden electric pole." The Commission Order seems to contemplate removing 15% from the total of Account 364, but in the calculation of the Companies' pole attachment charges, Account 364 is never used in total. Instead, LGE/KU used only the bare pole costs for the pole sizes specified by the Commission to be used to calculate two and three party pole attachment costs. Because the Companies did not propose to change the charge for cable attachments in this proceeding and the charge for cable attachments only became an issue when intervenor testimony was filed, the Companies have not had a reason to fully develop the supporting data for use in this rate proceeding.

Q. Do you have concerns about arbitrarily reducing pole costs by 15% for "minor appurtenances"?

A. Yes. The carrying cost calculation for the pole attachment charge is a simple calculation that does not account for a large number of costs that should be allocated to pole attachment service. KU and LGE's other rates are determined on the basis of fully-allocated cost of service. This has not been the case for cable television attachment charges which have been calculated using the simplified procedure identified in Administrative case No. 251. By using a simple formula rate to determine the charges, cable television attachment service has not received an allocation of a large number of common costs that would have been allocated to cable television attachment service if cable television attachment service had been included as a class in the Companies' cost of service studies. In a cost of service study, all of the Companies' common costs are fully distributed and assigned to each class of customers. By using a simple formula-rate calculation, as is done with the pole attachment charge, some legitimate common costs are not fully assigned to the cable television attachment charge. It would not be appropriate to make an arbitrary and unsupported adjustment for "minor appurtenances" without considering other costs that would properly be allocated to cable television customers in a fully allocated cost of service study.

Q. Can you provide examples of costs that would be allocated to cable television operators in fully allocated cost of service study that are not considered in the Companies' cable television charge?

A. Yes. In the Companies' cost of service studies, there are many cost items that are allocated to all customers classes on a fully-distributed basis that are not considered in the development of the cable television attachment charges. For example, expenses related to distribution supervision and engineering are recorded in Accounts 580 and 590. Supervision and engineering activities relate to poles as they do with conductors, transformers and other distribution facilities. Supervisors and engineers are routinely involved in the planning, design, scheduling, and oversight of operations and maintenance of poles. Even though it would be appropriate to assign a portion of distribution supervision and engineering expenses to poles in the determination of the cable television attachment charge, these expenses have not been traditionally included in the simple rate formula for calculating cable television attachment charges developed in Administrative Case No. 251. However, these costs are included in the determination of rates for KU and LGE's service to other rate classes. Likewise mapping expenses, distribution rental charges, miscellaneous expenses, customer records, and miscellaneous customer expenses are involved in providing service to pole attachments just as they are jointly related to providing service to other types of customers. The following operation and maintenance expenses are fully allocated to pole facilities in a cost of service study but are not assigned or otherwise captured in the calculation of the cable television attachment charge specified in Administrative Case No. 251:

Table 6

Operation and Maintenance Expenses Which are not currently included in Cable Television Attachment Charge

Account Number	Description
580	Distribution Operations Supervision & Engineering
588	Miscellaneous Distribution Expenses
589	Distribution Rents
590	Distribution Maintenance Supervision & Engineering Expenses
598	Miscellaneous Distribution Maintenance Expenses
903	Customer Records
905	Miscellaneous Customer Expenses

These operation and maintenance expenses are joint costs that are functionally assigned to all distribution functional groups in a cost of service study and allocated to all customers taking distribution service from KU or LGE. It would be inappropriate to include an arbitrary percentage for “minor appurtenances in these proceedings but ignore these other, more significant operation and maintenance expenses. Similarly, the pole attachment charge calculation also ignores a number of net cost rate base items that are fully distributed to all customer classes in a cost of service study. For example, the costs recorded as general plant include the cost of KU and LGE’s central office buildings. These costs are essential in running the business. Therefore it would be appropriate that these costs be allocated to cable television attachment service just as they are assigned to the Companies’ standard electric and gas services. Again, the simple rate formula used to calculate the cable television attachment charge has traditionally ignored these very real and legitimate costs. Likewise, cash working capital, materials and supplies, prepayments, plant held for future use, are just as necessary in providing service to pole attachments as they are for other customers. Pole-related costs are also included in Construction Work in Progress.

The following rate base items are fully allocated to pole facilities in a cost of service study but are not assigned or captured in the calculation of the cable television attachment charge specified in Administrative Case No. 251:

Table 7 **Rate Base Components** **Which are not currently included in** **Cable Television Attachment Charge**
General Plant
Plant Held for Future Use
Cash Working Capital
Materials and Supplies

Prepayments
Pole-Related Construction Work in Progress (CWIP)
General Plant CWIP

These rate base components are functionally assigned to all distribution functional groups, including poles, in a cost of service study and allocated to all customer classes served at the distribution level from KU or LGE. Again, it would be inappropriate to include an arbitrary percentage for "minor appurtenances" but ignore these rate base elements which are allocated to all other customers. In fact, these cost elements which are not considered in the cable television attachment charge calculation would exceed the actual cost of "minor appurtenance" based on the analysis provided in Rebuttal Exhibits MJB-5 and MJB-6.

Q. Has the Commission acknowledged that these types of common costs should be included in carrying charges for cable television attachments?

A. Yes. In its Administrative Case No. 251 dated September 17, 1982, the Commission stated as follows:

> We find it reasonable to allow a contribution by CATV toward the common costs of the utility which cannot be directly allocated to any particular classification of customer. However, each utility which includes such a contribution in its rate development must provide justification for the amount of such contribution which it proposes to include. (Order in Administrative Case No. 251, p. 12.)

Because the common cost items identified in Tables 6 and 7 are functionally assigned to pole-related costs and allocated to all customers receiving service from the Companies' distribution systems in their cost of service studies, it is appropriate to also allocate these costs to cable television pole attachment customers. There is no reason that the common costs identified in Table 6 and 7 should not be allocated to pole attachment customers just as they are to other customers.

Q. Have you performed an analysis updating the charges for current costs, removing a representative portion of the costs to reflect "minor appurtenance" and including the legitimate cost items shown in Tables 6 and 7?

A. Yes. In Rebuttal Exhibits MJB-5and MJB-6, I have updated the charges to reflect current costs (as in Rebuttal Exhibits MJB-1 and MJB- 2), excluded 15% for "minor appurtenances" and included the costs for the items shown in Tables 6 and 7. Table 8, below, compares the current charges to (i) the cost-based charges based on current data for KU and LGE using the rate formula from the last rate cases (as calculated in Rebuttal Exhibit MJB-1 and MJB-2), and (ii) the cost-based charges for KU and LGE after removal of 15% of pole plant costs for "minor appurtenances" and the addition of the legitimate cost items listed in Tables 6 and 7 of my testimony:

Table 8

Company	Current Charges	Charges Updated for Current Cost Data (Using Prior Rate Case Formula)	Charges Updated for Current Cost Data, Removing 15% for "Minor Appurtenances", and adding costs in Table 6 and 7
Kentucky Utilities	$ 9.69	$ 10.58	$10.08

Louisville Gas and Electric	$ 9.11	$ 11.08	$10.36

As can be seen from this table, KU and LGE's current cable television attachment charges are lower than what could be supported by an analysis of current costs, even if 15% of pole costs are removed to reflect appurtenances with the addition of legitimate and supportable common costs.

Q. What is your recommendation regarding the level of the cable television attachment charges?

A. KU and LGE did not propose to modify its cable television attachment charges in these rate case proceedings. As I have shown in Rebuttal Exhibits MJB-1, MJB-2, MJB-5 and MJB-6, higher charges could be supported using historical costs. However, the Companies did not file rate cases based on a historical test year, and there is no basis for adopting higher attachment charges based on historic data any more than there is a basis for adopting the lower attachment charges proposed by Ms. Kravtin based on historic data. Therefore, it is my recommendation that the Commission allow the current cable television rates to remain in effect. Clearly, KCTA has not met its burden of proof in supporting its proposed rates.

Q. How should cable TV attachment charges be set in future rate proceedings?

A. In future rate proceedings, attachment charges should be included as a separate class in the cost of service study and rate design. Essentially, Administrative Case No. 251 established a simplified procedure for developing attachment charges when attachment service was not included as a separate class in the cost of service study. However there was nothing in the Order in Administrative Case No. 251 that would constrain the Company from treating attachments as another service provided by the company in a cost of service study and developing rates using the cost of service information for this class in the future. This would be a more comprehensive and accurate method for developing pole attachments charges than the simplified formula developed in Administrative Case No. 251. If attachment service is treated as a separate class in a rate proceeding, the bare pole costs can be specifically assigned based on the costs for those pole sizes in account 364 to which attachments are made, and joint costs can be allocated to CATV like they are for all other rate classes. This would allow the Company to include the legitimate costs identified in Tables 6 and 7 above. It would also provide an opportunity for the Company to perform a more thorough analysis for KU and LGE to determine the amount of “minor appurtenances”, if any, and to support this determination with evidence in the rate proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Dr. Martin J. Blake**, 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.

Martin J Blake
Dr. Martin J. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2015.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2014			
35'	23,334	$ 12,786,133	$ 547.96
40'	59,312	31,220,040	526.37
	82,646	$ 44,006,173	$ 532.47
Three-User Poles			
40'	59,312	$ 31,220,040	$ 526.37
45'	23,443	35,703,828	1,523.01
	82,755	$ 66,923,867	$ 808.70

	Number of Attachments	Weighted Cost
Two-User Pole Charge		
\$532.47 x .1224 Usage Space Factor = \$ 65.17		
\$ 65.17 x .1806 Annual Carrying Charge = \$ 11.77	-	$ -
Three-User Pole Charge		
\$808.70 x .0759 Usage Space Factor = \$61.38		
\$ 61.38 x .1806 Annual Carrying Charge = \$11.08	87,509	$ 969,802
Weighted Total	87,509	$ 969,802
Weighted Average Annual Cost		$ 11.08

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	7.36%
Depreciation - Sinking Fund	0.67%
Income Tax (1)	3.53%
Property Tax and Insurance	1.10%
Operation and Maintenance (Page 3)	5.40%
Total	18.06%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.54%	0.90%	0.04%
Long Term Debt	42.71%	4.16%	1.78%
Common Equity	52.75%	10.50%	5.54%
Total Capitalization	100.00%		7.36%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0554 = 3.53%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31 , 2014

(1) Labor Charged to 593001 - Poles, Towers		
and Fixtures Subaccount	$ 74,304	
- Tree Trimming	159,440	
		$ 233,744
Total Labor		71,414,302
Total Administrative and General Expenses		$ 82,720,225

Assignment of a Portion of A & G Expenses to Poles

($233,744/$71,414,302) x $82,720,225 = $270,749

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures	
Subaccount 593001	$ 474,899
Tree Trimming of Electric Distribution	
Routes 593004	7,870,074
A & G Expenses Assigned to Poles	270,749
Total	$ 8,615,722

Adder to Annual Carrying Charges for O & M Expenses

$ 8,615,722	Expenses Assigned to Poles	=	5.40%
159,591,768	Plant in Service - Account 364		

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Estimated Number of Attachments	Average Installed Cost / Weighted Cost
Weighted Average Bare Pole Cost as of 10/31/2014				
35'	87,362	$ 23,026,482		$ 263.58
40'	140,885	97,115,087		689.32
	228,247	120,141,569		526.37
Three-User Poles				
40'	140,885	$ 97,115,087		$ 689.32
45'	69,359	73,792,804		1,063.93
	210,244	170,907,891		812.90
Two-User Pole Charge				
$526.37 x .1224 Usage Space Factor = $ 64.43				
$ 64.43 x .1714 Annual Carrying Charge = $ 11.04			-	$ -
Three-User Pole Charge				
$812.90 x .0759 Usage Space Factor = $61.70				
$ 61.70 x .1714 Annual Carrying Charge = $10.58			148,680	1,572,480
Weighted Total			148,680	$ 1,572,480
Weighted Average Annual Cost				10.58

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	7.23%
Depreciation - Sinking Fund	0.69%
Income Tax (1)	3.58%
Property Tax and Insurance	0.42%
Operation and Maintenance (Page 3)	5.23%
Total	17.14%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.93%	0.64%	0.03%
Long Term Debt	41.51%	3.78%	1.57%
Common Equity	53.56%	10.50%	5.62%
Total Capitalization	100.00%		7.23%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0562 = 3.58%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2014

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	45,882	
- Tree Trimming	406,135	
		$452,017
Total Labor		$100,042,631
Total Administrative and General Expenses		$103,261,735

<u>Assignment of a Portion of A & G Expenses to Poles</u>

($452,017/$100,042,631) x $103,261,735 = $466,562

<u>Expenses Assigned to Poles</u>

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$	619,579
Tree Trimming of Electric Distribution Routes 593004		16,088,333
A & G Expenses Assigned to Poles		$466,562
Total	$	17,174,474

<u>Adder to Annual Carrying Charges for O & M Expenses</u>

$ 17,174,474	Expenses Assigned to Poles	=	5.23%
328,470,051	Plant in Service - Account 364		

Kravtin Attachment 3, Table 1

Rebuttal Exhibit MJB-3

Comparison of Non-Levelized and Levelized Capital Recovery Carrying Charge Approaches

(a) Average Service Life	35
(b) Ratio Net to Gross Investment	0.5
(c) Straight Line Depreciation [1/(a)] as Fixed % of Gross Investment	2.86%
(d) Straight Line Depreciation [1/(a)] as Average % of Net Investment	5.72%
(e)Authorized Rate of Return (ROR) /Discount Factor (DF) as Fixed % of Net Investment	8.32%
(f)Authorized Rate of Return (ROR) /Discount Factor (DF) as Average % of Gross Investment	4.16%
(g) Sinking-Fund Depreciation [(f/(1+f)^(a-1)] as Fixed % of Gross Investment	1.31%

Inconsistent discount rates used to obtain the same $1,000 present value

	Non-Levelized (Straight Line Depreciation) Capital Carrying Charges							Levelized (Sinking Fund Depreciation) Capital Carrying Charges per Kravtin					
Year (1)	Net Investment (2)	Return Charge (3)=(2) x(4)	ROR as % Net Inv (4)	ROR as % Gross Inv (5)	Straight Line Depreciation (6)=(c)xGross	Capital Carry Charges (7)=(3)+(6)	Present Val @8.32% (8)	Gross Investment (9)	Return Charge (10)	ROR as % Gross Inv (11)	Sinking Fund Depreciation (12)=(g)*Gross	Capital Carry Charges (13)=(10)+(12)	Present Val @Gross RoR (14)
1	$ 1,000.00	$ 83.20	8.32%	8.32%	$ 28.57	$ 111.77	$103.19	$ 1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 52.56
2	971.43	80.82	8.32%	8.08%	28.57	$ 109.39	93.23	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 50.46
3	942.86	78.45	8.32%	7.84%	28.57	$ 107.02	84.20	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 48.45
4	914.29	76.07	8.32%	7.61%	28.57	$ 104.64	76.01	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 46.51
5	885.71	73.69	8.32%	7.37%	28.57	$ 102.26	68.58	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 44.65
6	857.14	71.31	8.32%	7.13%	28.57	$ 99.89	61.84	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 42.87
7	828.57	68.94	8.32%	6.89%	28.57	$ 97.51	55.73	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 41.16
8	800.00	66.56	8.32%	6.66%	28.57	$ 95.13	50.19	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 39.51
9	771.43	64.18	8.32%	6.42%	28.57	$ 92.75	45.18	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 37.94
10	742.86	61.81	8.32%	6.18%	28.57	$ 90.38	40.64	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 36.42
11	714.29	59.43	8.32%	5.94%	28.57	$ 88.00	36.53	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 34.97
12	685.71	57.05	8.32%	5.71%	28.57	$ 85.62	32.82	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 33.57
13	657.14	54.67	8.32%	5.47%	28.57	$ 83.25	29.45	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 32.23
14	628.57	52.30	8.32%	5.23%	28.57	$ 80.87	26.42	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 30.94
15	600.00	49.92	8.32%	4.99%	28.57	$ 78.49	23.67	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 29.71
16	571.43	47.54	8.32%	4.75%	28.57	$ 76.11	21.19	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 28.52
17	542.86	45.17	8.32%	4.52%	28.57	$ 73.74	18.95	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 27.38
18	514.29	42.79	8.32%	4.28%	28.57	$ 71.36	16.93	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 26.29
19	485.71	40.41	8.32%	4.04%	28.57	$ 68.98	15.11	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 25.24
20	457.14	38.03	8.32%	3.80%	28.57	$ 66.61	13.47	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 24.23
21	428.57	35.66	8.32%	3.57%	28.57	$ 64.23	11.99	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 23.26
22	400.00	33.28	8.32%	3.33%	28.57	$ 61.85	10.66	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 22.33
23	371.43	30.90	8.32%	3.09%	28.57	$ 59.47	9.46	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 21.44
24	342.86	28.53	8.32%	2.85%	28.57	$ 57.10	8.39	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 20.58
25	314.29	26.15	8.32%	2.61%	28.57	$ 54.72	7.42	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 19.76
26	285.71	23.77	8.32%	2.38%	28.57	$ 52.34	6.55	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 18.97
27	257.14	21.39	8.32%	2.14%	28.57	$ 49.97	5.77	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 18.22
28	228.57	19.02	8.32%	1.90%	28.57	$ 47.59	5.08	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 17.49
29	200.00	16.64	8.32%	1.66%	28.57	$ 45.21	4.45	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 16.79
30	171.43	14.26	8.32%	1.43%	28.57	$ 42.83	3.90	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 16.12
31	142.86	11.89	8.32%	1.19%	28.57	$ 40.46	3.40	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 15.47
32	114.29	9.51	8.32%	0.95%	28.57	$ 38.08	2.95	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 14.86
33	85.71	7.13	8.32%	0.71%	28.57	$ 35.70	2.55	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 14.26
34	57.14	4.75	8.32%	0.48%	28.57	$ 33.33	2.20	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 13.69
35	28.57	2.38	8.32%	0.24%	28.57	$ 30.95	1.89	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 13.15
	TOTAL/AVG	$1,497.60	8.32%	4.28%	$1,000.00	$2,497.60	**$1,000.00**		$1,456.00	4.16%	$460.14	$1,916.14	**$1,000.00**

Result of using different discount rates

Rebuttal Exhibit MJB-4

Comparison of Non-Levelized and Levelized Capital Recovery Carrying Charge Approaches

(a) Average Service Line	35
(b) Ratio Net to Gross Investment	0.5
(c) Straight Line Depreciation [1/(a)] as Fixed % of Gross Investment	2.86%
(d) Straight Line Depreciation [1/(a)] as Average % of Net Investment	5.72%
(e) Authorized Rate of Return (ROR)/Discount Factor (DF) as Fixed % if Net Investment	8.32%
(e) Authorized Rate of Return (ROR)/Discount Factor (DF) as Average % of Gross Investment	4.16%
(g) Sinking-Fund Depreciation [(f/1+f)^(a-1)] as Fixed % of Gross Investment	1.31%

	Non-Levelized (Straight Line Depreciation) Capital Carrying Charges							**Levelized (Sinking Fund Depreciation) Captial Carrying Charges per Kravtin**					
Year (1)	Net Investment (2)	Return Charge (3)=(2)x(4)	Return as % Net Inv (4)	Return as % Gross Inv (5)	Straight Line Depreciation (6)=(c)xGross	Capital Carry Charges (7)=(3)+(6)	Present Val @8.32% (8)	Gross Investment (9)	Return Charge (10)	Return as % Gross Inv (11)	Sinking Fund Depreciation '(12)=(g)*Gross	Captial Carry Charges (13)=(10)+(12)	Present Val @8.32% (14)
1	1,000.00	83.20	8.32%	8.32%	28.57	111.77	103.19	1,000.00	41.60	4.16%	13.15	54.75	50.54
2	971.43	80.82	8.32%	8.08%	28.57	109.39	93.23	1,000.00	41.60	4.16%	13.15	54.75	46.66
3	942.86	78.45	8.32%	7.84%	28.57	107.02	84.20	1,000.00	41.60	4.16%	13.15	54.75	43.08
4	914.29	76.07	8.32%	7.61%	28.57	104.64	76.01	1,000.00	41.60	4.16%	13.15	54.75	39.77
5	885.71	73.69	8.32%	7.37%	28.57	102.26	68.58	1,000.00	41.60	4.16%	13.15	54.75	36.71
6	857.14	71.31	8.32%	7.13%	28.57	99.89	61.84	1,000.00	41.60	4.16%	13.15	54.75	33.89
7	828.57	68.94	8.32%	6.89%	28.57	97.51	55.73	1,000.00	41.60	4.16%	13.15	54.75	31.29
8	800.00	66.56	8.32%	6.66%	28.57	95.13	50.19	1,000.00	41.60	4.16%	13.15	54.75	28.89
9	771.43	64.18	8.32%	6.42%	28.57	92.75	45.18	1,000.00	41.60	4.16%	13.15	54.75	26.67
10	742.86	61.81	8.32%	6.18%	28.57	90.38	40.64	1,000.00	41.60	4.16%	13.15	54.75	24.62
11	714.29	59.43	8.32%	5.94%	28.57	88.00	36.53	1,000.00	41.60	4.16%	13.15	54.75	22.73
12	685.71	57.05	8.32%	5.71%	28.57	85.62	32.82	1,000.00	41.60	4.16%	13.15	54.75	20.98
13	657.14	54.67	8.32%	5.47%	28.57	83.25	29.45	1,000.00	41.60	4.16%	13.15	54.75	19.37
14	628.57	52.30	8.32%	5.23%	28.57	80.87	26.42	1,000.00	41.60	4.16%	13.15	54.75	17.88
15	600.00	49.92	8.32%	4.99%	28.57	78.49	23.67	1,000.00	41.60	4.16%	13.15	54.75	16.51
16	571.43	47.54	8.32%	4.75%	28.57	76.11	21.19	1,000.00	41.60	4.16%	13.15	54.75	15.24
17	542.86	45.17	8.32%	4.52%	28.57	73.74	18.95	1,000.00	41.60	4.16%	13.15	54.75	14.07
18	514.29	42.79	8.32%	4.28%	28.57	71.36	16.93	1,000.00	41.60	4.16%	13.15	54.75	12.99
19	485.71	40.41	8.32%	4.04%	28.57	68.98	15.11	1,000.00	41.60	4.16%	13.15	54.75	11.99
20	457.14	38.03	8.32%	3.80%	28.57	66.61	13.47	1,000.00	41.60	4.16%	13.15	54.75	11.07
21	428.57	35.66	8.32%	3.57%	28.57	64.23	11.99	1,000.00	41.60	4.16%	13.15	54.75	10.22
22	400.00	33.28	8.32%	3.33%	28.57	61.85	10.66	1,000.00	41.60	4.16%	13.15	54.75	9.44
23	371.43	30.90	8.32%	3.09%	28.57	59.47	9.46	1,000.00	41.60	4.16%	13.15	54.75	8.71
24	342.86	28.53	8.32%	2.85%	28.57	57.10	8.39	1,000.00	41.60	4.16%	13.15	54.75	8.04
25	314.29	26.15	8.32%	2.61%	28.57	54.72	7.42	1,000.00	41.60	4.16%	13.15	54.75	7.42
26	285.71	23.77	8.32%	2.38%	28.57	52.34	6.55	1,000.00	41.60	4.16%	13.15	54.75	6.85
27	257.14	21.39	8.32%	2.14%	28.57	49.97	5.77	1,000.00	41.60	4.16%	13.15	54.75	6.33
28	228.57	19.02	8.32%	1.90%	28.57	47.59	5.08	1,000.00	41.60	4.16%	13.15	54.75	5.84
29	200.00	16.64	8.32%	1.66%	28.57	45.21	4.45	1,000.00	41.60	4.16%	13.15	54.75	5.39
30	171.43	14.26	8.32%	1.43%	28.57	42.83	3.90	1,000.00	41.60	4.16%	13.15	54.75	4.98
31	142.86	11.89	8.32%	1.19%	28.57	40.46	3.40	1,000.00	41.60	4.16%	13.15	54.75	4.60
32	114.29	9.51	8.32%	0.95%	28.57	38.08	2.95	1,000.00	41.60	4.16%	13.15	54.75	4.24
33	85.71	7.13	8.32%	0.71%	28.57	35.70	2.55	1,000.00	41.60	4.16%	13.15	54.75	3.92
34	57.14	4.75	8.32%	0.48%	28.57	33.33	2.20	1,000.00	41.60	4.16%	13.15	54.75	3.62
35	28.57	2.38	8.32%	0.24%	28.57	30.95	1.89	1,000.00	41.60	4.16%	13.15	54.75	3.34
	TOTAL/AVG	$1,497.60	8.32%	4.28%	$1,000.00	$2,497.60	$1,000.00		$1,456.00	4.16%	$460.15	$1,916.15	$617.89

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2014			
Two-User Poles (Less 15% for Appurtenances)			
35'	23,334	$ 10,868,213	$ 465.77
40'	59,312	26,537,034	447.41
	82,646	$ 37,405,247	$ 452.60
Three-User Poles (Less 15% for Appurtenances)			
40'	59,312	$ 26,537,034	$ 447.41
45'	23,443	30,348,254	1,294.56
	82,755	$ 56,885,287	$ 687.39
Common Plant (Page 4)	82,755	$ 3,477,177	$ 42.02
Cash Working Capital (Page 3)	82,755	$ 450,275	$ 5.44

Pole Cost (Space Factor determined from 3 user Pole)

		Number of Attachments	Weighted Cost
Pole	$687.39 x .0759 Usage Space Factor = $52.17		
	$ 52.17 x .1899 Annual Carrying Charge (ACC) = $9.91	87,509	$ 866,965
Common	$42.02 x .0759 x 0.1266 = $0.40		35,322
CWC	$5.44 x .0759 x 0.1088 = $0.04		3,933
	Weighted Total	87,509	$ 906,220
	Weighted Average Annual Cost		$ 10.36

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

	Poles	General Plant	Working Capital
Proposed Rate of Return	7.36%	7.36%	7.36%
Depreciation - Sinking Fund	0.67%	0.67%	
Income Tax (1)	3.53%	3.53%	3.53%
Property Tax and Insurance	1.10%	1.10%	
Operation and Maintenance (Page 3)	6.33%		
Total	18.99%	12.66%	10.88%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.54%	0.90%	0.04%
Long Term Debt	42.71%	4.16%	1.78%
Common Equity	52.75%	10.50%	5.54%
Total Capitalization	100.00%		7.36%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0554 = 3.53%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31 , 2014

(1) Labor Charged to 593001 - Poles, Towers				
and Fixtures Subaccount	$	74,304		
- Tree Trimming		159,440		
			$	233,744
Total Labor				71,414,302
Total Administrative and General Expenses			$	82,720,225

Assignment of a Portion of A & G Expenses to Poles

($233,744/$71,414,302) x $82,720,225 = $270,749

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures		
Subaccount 593001	$	474,899
Tree Trimming of Electric Distribution		
Routes 593004		7,870,074
A & G Expenses Assigned to Poles		270,749
Other Common Expenses (Page 4)		1,490,253
Total	$	10,105,975

Adder to Annual Carrying Charges for O & M Expenses

$ 10,105,975	Expenses Assigned to Poles	=	6.33%
159,591,768	Plant in Service - Account 364		

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of10/31/2014				
Two-User Poles (Less 15% for Appurtenances)				
35'	87,362	$ 19,572,510		$ 224.04
40'	140,885	82,547,824		585.92
	228,247	102,120,334		447.41
Three-User Poles				
40'	140,885	$ 82,547,824		$ 585.92
45'	69,359	62,723,883		904.34
	210,244	145,271,707		690.97
Common Plant (Page 4)	210,244	$6,318,932		$ 30.06
Cash Working Capital (Page 3)	210,244	1,215,818		$ 5.78

		Estimated Number of Attachments	Weighted Cost
Two-User Pole Charge			
	\$447.41 x .1224 Usage Space Factor = \$ 54.76		
	\$ 54.76 x .1861 Annual Carrying Charge = \$ 10.19	-	$ -
Three-User Pole Charge			
Pole	\$690.97 x .0759 Usage Space Factor = \$52.44		
	\$ 52.44 x .1861 Annual Carrying Charge = \$9.76	148,680	1,450,979
Common	\$30.06 x .0759 x 0.1191 = \$0.27		40,405
CWC	\$5.78 x .0759 x 0.1081 = \$0.05		7,052
	Weighted Total	148,680	$ 1,498,436
	Weighted Average Annual Cost		10.08

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

	Poles	General Plant	Working Capital
Proposed Rate of Return	7.23%	7.23%	7.23%
Depreciation - Sinking Fund	0.69%	0.69%	
Income Tax (1)	3.58%	3.58%	3.58%
Property Tax and Insurance	0.42%	0.42%	
Operation and Maintenance (Page 3)	6.70%		
Total	18.61%	11.91%	10.81%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.93%	0.64%	0.03%
Long Term Debt	41.51%	3.78%	1.57%
Common Equity	53.56%	10.50%	5.62%
Total Capitalization	100.00%		7.23%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0562 = 3.58%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2014

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	45,882	
- Tree Trimming	406,135	
		$452,017
Total Labor		$100,042,631
Total Administrative and General Expenses		$103,261,735

Assignment of a Portion of A & G Expenses to Poles

($452,017/$100,042,631) x $103,261,735 = $466,562

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$	619,579
Tree Trimming of Electric Distribution Routes 593004		16,088,333
A & G Expenses Assigned to Poles		$466,562
Other Common Expenses (Page 4)		$4,817,952
Total	$	21,992,426

Adder to Annual Carrying Charges for O & M Expenses

$ 21,992,426	Expenses Assigned to Poles	=	6.70%
328,470,051	Plant in Service - Account 364		

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of10/31/2014				
Two-User Poles (Less 15% for Appurtenances)				
35'	87,362	$ 21,875,158		$ 250.40
40'	140,885	92,259,333		654.86
	228,247	114,134,491		500.05
Three-User Poles				
40'	140,885	$ 92,259,333		$ 654.86
45'	69,359	70,103,164		1,010.73
	210,244	162,362,496		772.26
Common Plant (Page 4)	210,244	$7,062,335		$ 33.59
Cash Working Capital (Page 3)	210,244	1,358,855		$ 6.46

		Estimated Number of Attachments	Weighted Cost
Two-User Pole Charge			
	$500.05 x .1224 Usage Space Factor = $ 61.21		
	$ 61.21 x .1861 Annual Carrying Charge = $ 11.39	-	$ -
Three-User Pole Charge			
Pole	$772.26 x .0759 Usage Space Factor = $58.61		
	$ 58.61 x .1861 Annual Carrying Charge = $10.91	148,680	1,621,683
Common	$33.59 x .0759 x 0.1191 = $0.30		45,159
CWC	$6.46 x .0759 x 0.1081 = $0.05		7,881
	Weighted Total	148,680	$ 1,674,723
	Weighted Average Annual Cost		11.26

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

	Poles	General Plant	Working Capital
Proposed Rate of Return	7.23%	7.23%	7.23%
Depreciation - Sinking Fund	0.69%	0.69%	
Income Tax (1)	3.58%	3.58%	3.58%
Property Tax and Insurance	0.42%	0.42%	
Operation and Maintenance (Page 3)	6.70%		
Total	18.61%	11.91%	10.81%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.93%	0.64%	0.03%
Long Term Debt	41.51%	3.78%	1.57%
Common Equity	53.56%	10.50%	5.62%
Total Capitalization	100.00%		7.23%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0562 = 3.58%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2014

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	45,882	
- Tree Trimming	406,135	
		$452,017
Total Labor		$100,042,631
Total Administrative and General Expenses		$103,261,735

Assignment of a Portion of A & G Expenses to Poles

($452,017/$100,042,631) x $103,261,735 = $466,562

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$	619,579
Tree Trimming of Electric Distribution Routes 593004		16,088,333
A & G Expenses Assigned to Poles		$466,562
Other Common Expenses (Page 4)		$4,817,952
Total	$	21,992,426

Adder to Annual Carrying Charges for O & M Expenses

$ 21,992,426	Expenses Assigned to Poles	=	6.70%
328,470,051	Plant in Service - Account 364		