COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00349**

In the Matter of:

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

DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE KENTUCKY

OFFICE OF THE ATTORNEY GENERAL

MARCH 5, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in the Richmond, Virginia area. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 40-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have provided testimony relating to class cost of service and rate design before this Commission on numerous occasions including previous Kentucky Utilities ("KU") and Louisville Gas & Electric ("LG&E") rate cases (collectively, the "Companies").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates has been retained by the Kentucky Office of the Attorney General ("OAG") to assist in its evaluation of the accuracy and reasonableness of KU's electric class cost of service study ("CCOSS") and LG&E's electric and gas CCOSS, the Companies' proposed distribution of revenues by class and residential rate designs. The purpose of my testimony, therefore, is to comment on the Companies' proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the Kentucky Public Service Commission, KU has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the FERC), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1] 324 U.S. 581, 65 S. Ct. 829.

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF THE COMPANIES' VARIOUS CCOSS.

A. In conducting my independent analysis, I reviewed the structure and organization of the Companies' witness William Seelye's various CCOSS and reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed Mr. Seelye's selection of allocators to specific rate base, revenue, and expense accounts. I then verified the accuracy of Mr. Seelye's model by replicating his results using my own computer models. Finally, I adjusted certain aspects of Mr. Seelye's studies to better reflect cost causation and cost incidence by rate schedule and customer class.

II. KU AND LG&E ELECTRIC OPERATIONS

A. Class Cost of Service

Q. ARE THERE CERTAIN ASPECTS OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TEND TO BE MORE CONTROVERSIAL THAN OTHERS?

A. Yes. For decades, cost allocation experts and to some degree, utility commissions, have disagreed on how generation and certain distribution plant accounts should be allocated across classes. Beyond a doubt, these two issue areas are the most contentious and often have the largest impact on the results of achieved class rates of return ("RORs").

1. Allocation Methods for Generation Plant

Q. BEFORE YOU DISCUSS THE SPECIFICS OF THE COMPANIES' PROPOSED METHOD TO ALLOCATE GENERATION-RELATED COSTS, PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO THESE RESOURCES.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour ("kWh") would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that the Companies experience periods (hours) of higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system.

To further complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy (variable cost)/capacity (fixed cost) trade-off relating to production costs. That is, utilities design their mix of production facilities to minimize the total costs of variable energy and fixed capacity, while also ensuring there is enough available capacity to meet peak demand requirements. The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Coal units require high capital expenditures resulting in large investments per kW of capacity, but operate very efficiently such that their variable running costs per kWh are very low. Conversely, combustion turbine units are relatively inexpensive to build per kW of capacity but are much less efficient and incur significantly higher variable running costs per kWh of output. Due to varying levels of demand placed on a utility's system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its total cost of service.

The investment (capacity) costs of generation facilities are fixed in nature and are considered sunk investment costs. At the same time, the energy cost of running generation plants tends to be almost all variable in nature such that base load units tend to have low variable running costs whereas peaking units tend to have much higher variable running costs per kWh. As a result, generation assets tend to be dispatched based upon the variable running costs of each unit wherein lower variable cost units are dispatched before higher cost units. As such, total system production costs vary each hour of the year.

Q. APPROXIMATELY HOW MANY COST ALLOCATION METHODOLOGIES EXIST RELATING TO THE ALLOCATION OF GENERATION PLANT?

A. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[2]

[2] Principles of Public Utility Rates, Second Edition, page 495.

Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

<u>Single Coincident Peak ("1-CP")</u> -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning one hundred percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as KU had a peak load of 6,500 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 6,500 mW for 1 hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a “free ride” on the assignment of generation costs that this class requires.

4-CP -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

Summer and Winter Coincident Peak (“S/W Peak”) -- The S/W Peak method was developed because some utilities’ annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is no more reasonable than the 1-CP method.

12-CP -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility’s generation facilities than does the 1-CP or 4-CP methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

<u>Peak and Average ("P&A")</u> -- The various P&A methodologies rest on the premise that a utility's generation facilities are designed and placed into service to meet peak load <u>and</u> serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on some arbitrary factor such as system coincident load factor.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

<u>Average and Excess ("A&E")</u> -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a “free-ride” under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak (“BIP”) -- The BIP method is also known as a production stacking method that explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility’s resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility’s actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors tend to run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods.

Finally, wind and solar generating facilities may only produce energy when environmental conditions are present; i.e., wind or sunshine. As a result, their reliability factors are such that they may not be relied upon to meet peak loads at all times. For example, many utilities experience peak demands in the early morning and evening hours when there is either no sunlight present or minimal sunlight available for solar generation. As such, wind and solar generating units are classified as energy-related.

Probability of Dispatch -- The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year (8,760 hours). Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only those few peak hours. The hourly capacity costs for each generating asset are summed to develop hourly investment cost responsibilities. These hourly investments are then assigned to individual rate classes based on class contributions to system load for each hour of the year. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

Equivalent Peaker ("EP") -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant level of assumptions regarding the current (or future) costs of various generating alternatives.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. DO KU AND LG&E ACKNOWLEDGE THE COST CAUSATION CONCEPT OF THE ENERGY/CAPACITY TRADEOFF THAT EXISTS AS IT RELATES TO THEIR PLANNING, DISPATCH, AND OPERATION OF THEIR VARIOUS GENERATING RESOURCES?

A. Yes. In their 2018 IRP Reserve Margin Analysis, which is provided as an Appendix to their 2018 Integrated Resource Plan,[3] the Companies' state as follows in the Executive Summary:

[3] *See* Case No. 2018-00348.

> The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. **In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy**, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. (page 3) [Emphasis added]

Q. CAN YOU PROVIDE EXAMPLES OF THE ENERGY/CAPACITY TRADEOFF SPECIFIC TO KU AND LG&E?

A. Yes. Consider Trimble Unit 2 which is a base load unit that has a capacity of 629 mW[4]: the Companies' gross investment in this unit is $1.412 billion, which equates to a capacity cost of $2,244 per KW.[5] This generating unit operates very efficiently with a forecasted fuel cost of 1.96¢ per kWh of output.[6] At the other extreme, consider Haefling Units 1 and 2 which are peaker units that each has a capacity of 21 mW: the Companies' gross investment in each of these units is $2.199 million, which equates to a capacity cost of $105 per KW. These units are much less efficient and operate with an average forecasted fuel cost of 12.54¢ per kWh of output.

2. <u>KU and LG&E Combined Generation Assets and System Load Characteristics</u>

Q. PLEASE SUMMARIZE THE COMPANIES' PORTFOLIO OF GENERATION ASSETS.

A. KU and LG&E jointly dispatch their generation assets such that the following is a summary of the combined portfolio of generation assets during the forecasted test year:

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[4] 629 MW is the combined KU and LG&E ownership percentage of this unit. The total capacity of Trimble 2 is 839 MW.
[5] Per response to AG-KIUC 1-126.
[6] Per response to AG-KIUC 1-130.

TABLE 1
Summary of KU and LG&E Generation Portfolio[7]

Designation	Fuel Type	Capacity (MW)	Gross Investment 12/31/20
Base Load	Coal	4,999	$7,876.4 million
Base Load	Gas	808	$570.2 million
Total Base Load		5,807	$8,446.6 million
Intermediate	Gas	521	$193.7 million
Intermediate	Coal	464	$1,021.0 million
Total Intermediate		985	$1,214.7 million
Peaker	Gas/Oil	1,941	$691.3 million
Other	Solar/Hydro	148.3	$222.0 million
Total		8,881.3	$10,574.6 million

The details of the Companies' portfolio of generation assets along with capacities, variable fuel costs and investments are provided in my Schedule GAW-2.

Q. HOW DOES THIS OWNED CAPACITY COMPARE TO THE COMPANIES' SYSTEM PEAK LOAD DURING THE FORECASTED TEST YEAR?

A. The combined forecasted KU and LG&E system coincident peak ("CP") load is 6,111 MW.[8] However, this amount includes 74 MW of opportunity sales to municipals in which KU only makes sales to these customers "when marginal revenues exceed the marginal cost of generating energy to sell and that energy is not needed by retail customers."[9] Furthermore, the Companies' forecasted CP of 6,111 MW includes load from interruptible customers wherein a detailed evaluation of hourly loads clearly indicates that these customers are not forecasted to be interrupted at the time of the system peak. In this regard, the Companies have contractual curtailable service of 127

[7] Source: Response to AG-KIUC 1-126.
[8] Per response to AG-KIUC 1-114. Note: this amount excludes off-system sales but includes opportunity sales to municipals and interruptible load.
[9] Per response to AG-KIUC 1-135.

MW.[10] Therefore, the Companies forecasted firm peak load is 5,910 MW (6,111 MW minus 74 MW minus 127 MW).

Q. BY COMPARING THE COMPANIES' FORECASTED FIRM PEAK LOAD OF 5,910 MW TO THEIR BASE LOAD GENERATION NAMEPLATE CAPACITY OF 5,807 MW, IT WOULD APPEAR THAT THE COMPANIES CAN MEET ALMOST ALL OF THEIR LOAD REQUIREMENTS THROUGHOUT THE YEAR WITH JUST THEIR BASE LOAD GENERATING FACILITIES. IS THIS A REASONABLE INFERENCE?

A. Not entirely. As will be explained later in my testimony, the Companies' joint loads for the vast majority hours of the year are at, or below, the rated, or nameplate capacity of its base load generation units. However, all units have planned maintenance outages and experience unplanned forced outages. Therefore, one or more units may not be available each hour of the year. Furthermore, and due to the low cost of wholesale power (particularly during off-peak hours), it is sometimes cheaper for KU and LG&E to purchase blocks of power rather than dispatch certain generating units.

Q. THE ABOVE CAPACITY TO DEMAND RELATIONSHIP OF 8,881 MW TO FIRM PEAK LOAD OF 5,910 MW INDICATES A RESERVE MARGIN OF 50.3%. HOW DOES THIS COMPARE TO THE COMPANIES' TARGET RESERVE MARGIN?

A. In response to AG-KIUC 1-123, the Companies indicated that their "planning" reserve margin for 2020 was 28.5% wherein the Companies also stated "the capacity of the supply resources that have been allocated to each company over the years was higher than the 2020 forecasted summer peak by 47.8 percent for KU and 3.2 percent for LG&E" which is entirely consistent with the calculation in the question.

Q. HOW DO THESE RESERVE MARGINS COMPARE TO NEIGHBORING REGIONS?

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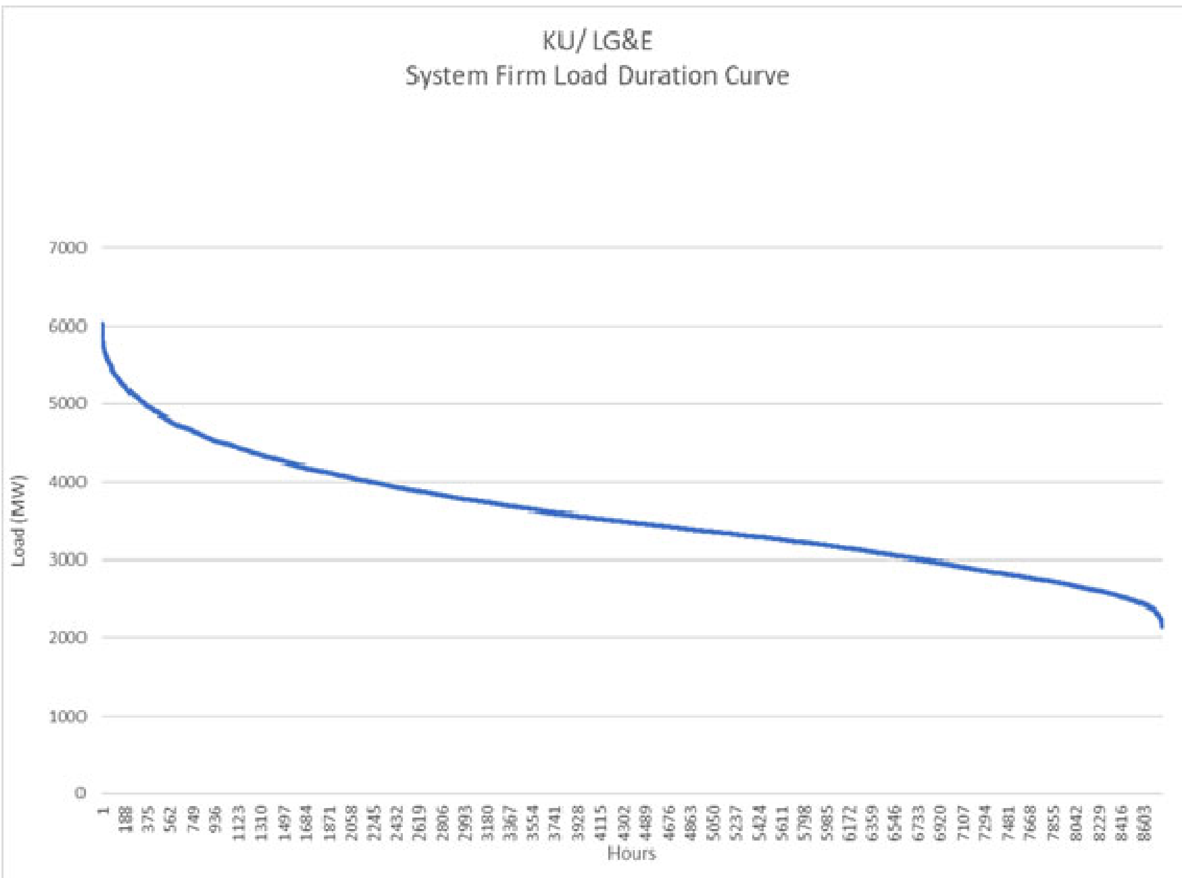
[10] Per response to AG-KIUC 1-121 and AG-KIUC 1-114.

A. As noted in the Companies' 2018 IRP Reserve Margin Analysis, MISO's target reserve margin is 17.1%, PJM's target reserve margin is 15.8% and TVA's target reserve margin is 15% (page 10).

Q. HAVE YOU EXAMINED THE COMPANIES' COMBINED SYSTEM LOAD REQUIREMENTS THROUGHOUT THE FORECASTED TEST YEAR?

A. Yes. In response to AG-KIUC 1-114, the Companies provided their forecast of system loads for every hour of the test year. As a result, I was able to develop the Companies' load duration curve. A graph of the Companies' system load duration curve is provided below:



Q. PLEASE EXPLAIN WHAT A LOAD DURATION CURVE REPRESENTS.

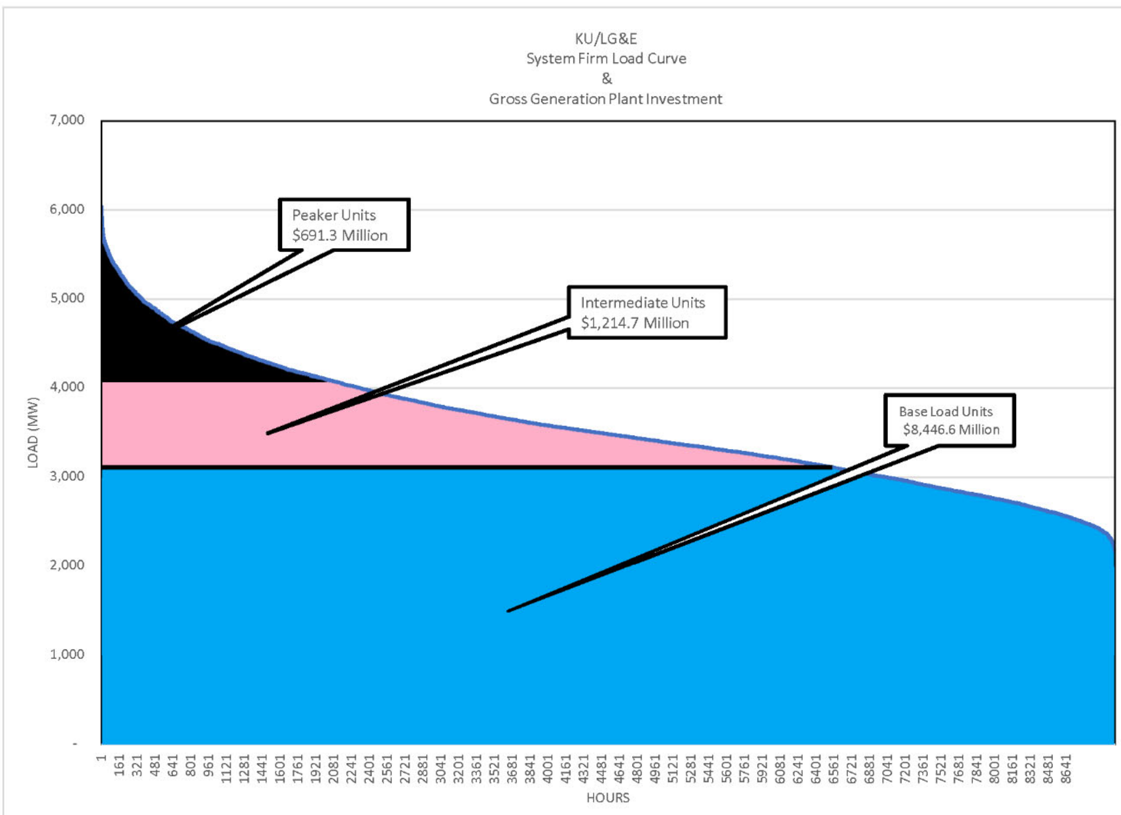
A. A load duration curve shows the demand by hour for an entire year such that the first hour on the graph represents the annual system peak while the last hour shows the lowest hourly demand for the test year. In other words, it is a curve that is sorted from highest hourly demand to lowest hourly demand. The area under the curve represents the total energy required during a year and most importantly, shows the incidence and duration of load requirements.

Q. EARLIER YOU INDICATED THAT THE COST CAUSATION FOR GENERATION COSTS RELATES TO THE ENERGY/CAPACITY TRADEOFF BETWEEN VARIOUS GENERATION RESOURCES. HOW SHOULD THIS COST CAUSATION PRINCIPLE BE REFLECTED WITHIN CLASS COST ALLOCATION STUDIES?

A. As noted earlier, and acknowledged by KU and LG&E, base load units provide low cost energy throughout the year such that they are planned to be dispatched first within the entire portfolio of generation assets. As a result, these base load units operate and provide benefits to all customers during most hours of the year. Therefore, the assignment of costs associated with base load units should be commensurate with how customers utilize these resources throughout the year; i.e., on an energy (kWh) basis. At the other extreme, peaker units are planned and designed to operate for only a few hours of the year during peak load requirements. As such, these peaker units should be allocated to classes based on their respective loads during these peak periods. Finally, intermediate plants are just that – those units that are planned and operate during intermediate load periods wherein these costs should be allocated to classes based on their respective loads during shoulder or intermediate system load periods.

Q. CAN YOU GRAPHICALLY SHOW THE RELATIONSHIP BETWEEN THE COMPANIES' GENERATION GROSS INVESTMENT TO ITS SYSTEM LOAD DURATION CURVE?

A. Yes. The following graph provides the Companies' forecasted test year system load duration curve along with the capacity associated with its base load, intermediate, and peaker units. In developing this graph, I defined the peak period under the load duration curve based on the capacity of the Companies' peaker units (1,941 mW). The intermediate period was defined as the capacity of the Companies' intermediate generation capacity (985 mW). Finally, the base load of 3,111 mW are those hours below the combined peak and intermediate periods. As shown in this graph, the area under the base load portion of the load duration curve serves all customers' load requirements for the plurality of the year and represents the majority of the Companies' total gross investment in generation plant ($8,446.6 million). The area under the intermediate portion of the load duration curve serves customers' load requirements for a smaller portion of the year with a smaller gross investment ($1,214.7 million) while the area under the peak portion of the load duration curve serves customer load requirements for only a few hours of the year with a relatively minimal level of gross investment ($691.3 million).[11]



[11] Note: the capacity and costs associated with solar and hydro are not included in this graph due to their inability to serve load every hour of the year and are therefore, not considered as truly base load, intermediate, or peaking units.

Q. DOES THE ABOVE GRAPH CONCEPTUALLY SHOW HOW GENERATION INVESTMENT COSTS ARE INCURRED AND HOW THEY SHOULD BE ALLOCATED ACROSS CLASSES?

A. Yes. The investment costs associated with each of the three periods should be allocated to individual rate classes commensurate with the loads they place on the system during these periods. This is most important because from a cost causation perspective we see that the majority of generation investment is related to base load units that serve all customers throughout the year, while the peak period investment costs are significantly less and should be allocated to customer classes based on their loads during peak periods.

In practice, this is most important because certain classes such as large industrials tend to use energy more uniformly throughout the year (i.e., have higher load factors) while other customers and classes tend to "drive the peak" in that these classes are responsible for a much larger percentage of load during peak periods than high load factor customers. As a result of these realities, residential and small commercial customers should be assigned relatively more responsibility to peak periods than base load periods. At the same time, all classes should be assigned their respective pro-rata share of the utilization of base load costs during base load periods. In short, class cost responsibility should coincide with the loads they place on the system at various times and load levels along with the specific investment costs required to serve these loads during the same time periods.

3. <u>KU and LG&E's Proposed Loss of Load Probability ("LOLP") Allocation Method</u>

Q. PLEASE EXPLAIN HOW COMPANY WITNESS SEELYE ALLOCATED GENERATION PLANT COSTS TO INDIVIDUAL RATE CLASSES.

A. Mr. Seelye relied upon Company-calculated system loss of load probabilities for each hour of the forecasted test year. At the same time, Mr. Seelye estimated every class' load for each hour of the forecasted test year. Then for each hour, Mr. Seelye multiplied the weighted LOLP by each class' contribution to load. These weighted class allocation factors are then summed for all hours that had any probability of loss of load to develop his ultimate generation allocation factor. To further explain, consider the following hypothetical example that shows the methodology utilized by Mr. Seelye to develop his generation allocation factor:

TABLE 2
Seelye Generation Allocation Factor Method
(Hypothetical Example)

Hour	Hourly System Load	Hourly LOLP	Hourly LOLP Weight	Load (MW) Resid.	Load (MW) Comm.	Load (MW) Industrial
A	6,350	0.5200%	53.89%	3,175	635	2,540
B	6,325	0.3600%	37.31%	3,158	632	2,535
C	6,310	0.0800%	8.29%	3,154	631	2,525
D	6,305	0.0050%	0.52%	3,150	630	2,525
All Other Hours		0.0000%	0.00%	Varies in Descending Order		
Total		0.9650%	100.00%			

Hour	Percent of Total Load Resid.	Percent of Total Load Comm.	Percent of Total Load Industrial	Hourly Allocation Weight Resid.	Hourly Allocation Weight Comm.	Hourly Allocation Weight Industrial	Hourly Allocation Weight Total
A	50.00%	10.00%	40.00%	26.94%	5.39%	21.55%	53.89%
B	49.93%	9.99%	40.08%	18.63%	3.73%	14.95%	37.31%
C	49.99%	10.00%	40.02%	4.14%	0.83%	3.32%	8.29%
D	49.96%	9.99%	40.05%	0.26%	0.05%	0.21%	0.52%
All Other Hours				0.00%	0.00%	0.00%	0.00%
Total				49.97%	9.99%	40.03%	100.00%

In the above hypothetical example, there are only four hours in which there is a calculated LOLP greater than zero; i.e., the other 8,756 hours of the year have a zero probability of not meeting system load.[12] The sum of all hours' LOLPs is 0.965%. Therefore, the weighted LOLP in Hour A is 53.89% of all LOLP hours (0.52% ÷ 0.965%). Each class's relative load in Hour A is then multiplied by 53.89%. For example, the residential load in Hour A is 3,175, which is 50% of the system load. This 50% residential contribution in Hour A is then multiplied by the LOLP weight of 53.89% to arrive at a residential weight for Hour A of 26.94%. These weighted class contributions are then summed for all hours with an LOLP greater than zero to arrive at the ultimate allocation factors of 49.97% for residential, 9.99% for commercial, and 40.03% for industrial.[13]

[12] Assuming a non-leap year.
[13] Note: Printed amounts do not sum to exactly 100% due to rounding in the printed example.

Once Mr. Seelye's class generation allocation factors are developed, these percentages are then multiplied by KU and LG&E's <u>total</u> investment in generation plant (base load plus intermediate plus peaker units on a combined basis).

Q. BEFORE YOU DISCUSS THE DETAILS AND IMPLICATIONS OF MR. SEELYE'S APPROACH TO ALLOCATE GENERATION-RELATED COSTS, PLEASE BRIEFLY EXPLAIN THE CONCEPT OF LOLP.

A. In the most basic sense, LOLP is a statistical evaluation of the probability of a utility not being able to meet its load obligations at any point in time given its forecasted load requirement (demand) and available sources of supply (supply). To the extent that demand exceeds supply, there is a positive loss of load probability. Similarly, to the extent there is enough supply relative to demand, the LOLP is equal to zero. In developing supply availability, the LOLP considers not only the rated capacity of generation resources but also reflects scheduled and forced outage rates of particular units as well as other supply-side constraints and resources. The specifics of KU and LG&E's LOLP modeling and estimation procedures will be discussed later in my testimony.

Q. EARLIER YOU SHOWED THAT ON A SYSTEM BASIS, KU AND LG&E HAVE INSTALLED GENERATION CAPACITY OF 8,881 MW AS COMPARED TO ITS FORECASTED SYSTEM FIRM PEAK LOAD OF 5,910 MW. GIVEN THE FACT THAT THE INSTALLED GENERATION CAPACITY GREATLY EXCEEDS THE COMPANIES' FORECASTED FIRM PEAK DEMAND, HOW IS IT POSSIBLE TO HAVE ANY HOURS WITH A LOLP GREATER THAN ZERO?

A. In reality, given the excess capacity within the KU/LG&E system, there is no reasonable possibility that the Companies cannot, or will not, be able to meet its firm load requirements each and every hour of the year with its own generation resources. While I understand and recognize that all generation capacity may not be available each and every hour of the year due to outages or other constraints, it is unconscionable to believe that even with a maximum firm peak demand of 5,910 MW, there would be more than 2,971 MW of generation capacity unavailable (8,881 MW minus 5,910 MW).

Q. NOTWITHSTANDING THE TREMENDOUS AMOUNT OF EXCESS GENERATION CAPACITY WITHIN THE KU/LG&E SYSTEM, HAVE YOU BEEN ABLE TO DETERMINE IF THE COMPANIES' CALCULATED LOLPs ARE SYSTEMATICALLY FLAWED?

A. Yes. In response to AG-KIUC 1-122, the Companies' provided its calculated LOLPs, amounts of unserved energy (mWh) and system loads (mW) for every hour of the forecasted test year. In addition, the Companies' provided class loads for every hour of the forecasted test year in response to AG-KIUC 1-114. With this information, the total system loads provided in its LOLP data (AG-KIUC 1-122) exactly match the class loads provided in AG-KIUC 1-114 for every hour of the year.[14] The system loads reflected in the Companies' LOLP analysis include not only firm loads but also non-firm loads – namely, KU sales to municipals as well as KU and LG&E interruptible loads subject to curtailment under the Curtailable Service Rider ("CSR") mechanism.

To illustrate, the hour with the highest LOLP (8/13/21 at 1400 hours) is based on a total system load of 6,111 MW wherein the LOLP calculates an expected unserved load of 8.3 MW. In other words, during this hour, the Companies' calculations indicate that its own generation supply will fall short of meeting demand by 8.3 MW. However, the 6,111 MW system load in this hour includes 74 MW of municipal load. As indicated in response to AG-KIUC 1-135, these sales for resale are only made available when "energy is not needed by retail customers." Therefore, since the Companies' own LOLP indicates there will be insufficient capacity to meet retail loads, the 74 MW of municipal load should be subtracted, which would then produce in excess of 65.7 MW of capacity (74 MW minus 8.3 MW). This situation holds true in every single hour in which there is a positive LOLP and corresponding expected unserved load ability.

Furthermore, in response to AG-KIUC 1-117, the Companies provided its forecasted curtailments for each hour of the test year. Within its forecast modeling, the Companies assumed curtailments for only nine hours during the entire year.[15] However, the Companies forecast shows that the annual system peak load will occur on 8/13/21 at

[14] The system loads provided with the LOLP analysis exclude off-system sales such that the off-system sales loads provided in AG-KIUC 1-114 must be excluded as well.

[15] The forecasted curtailments occur on 7/19/21 (1 hour for 41 MW), 7/22/21 (1 hour for 33 MW), 7/23/21 (4 hours for 36 to 48 MW), 9/21/21 (1 hour for 29 MW), and 9/23/21 (2 hours for 99 to 116 MW).

1400 hours, yet there are no curtailments forecasted for this hour. Indeed, the Companies forecast no curtailments during any of the highest ten system peak load hours and when the Companies modeling does assume curtailments, it never curtails up to the allowable 127 MW.[16] Therefore, the supply sufficiency (excess) during the hour with the highest forecasted LOLP (unserved load) then becomes 65.7 MW plus 127 MW, or 192.7 MW even under the Companies own modeling assumptions of plant availability within its LOLP analysis.

Finally, I examined the forecasted availability in dispatch of the Companies' generation resources on peak days and discovered unrealistic assumptions within the Companies forecasting model. That is, during forecasted peak load hours, a large number of generating units are offline or are only operating at reduced capacities. To illustrate, the forecasted annual peak day is 8/13/21 in which the four highest annual hourly peak loads occur. The following table provides those units that the Companies' assumed were either unavailable or not fully dispatched to meet load requirements:

TABLE 3
Forecasted Units Offline or At Reduced Capacity on
8/13/21 (Peak Day)

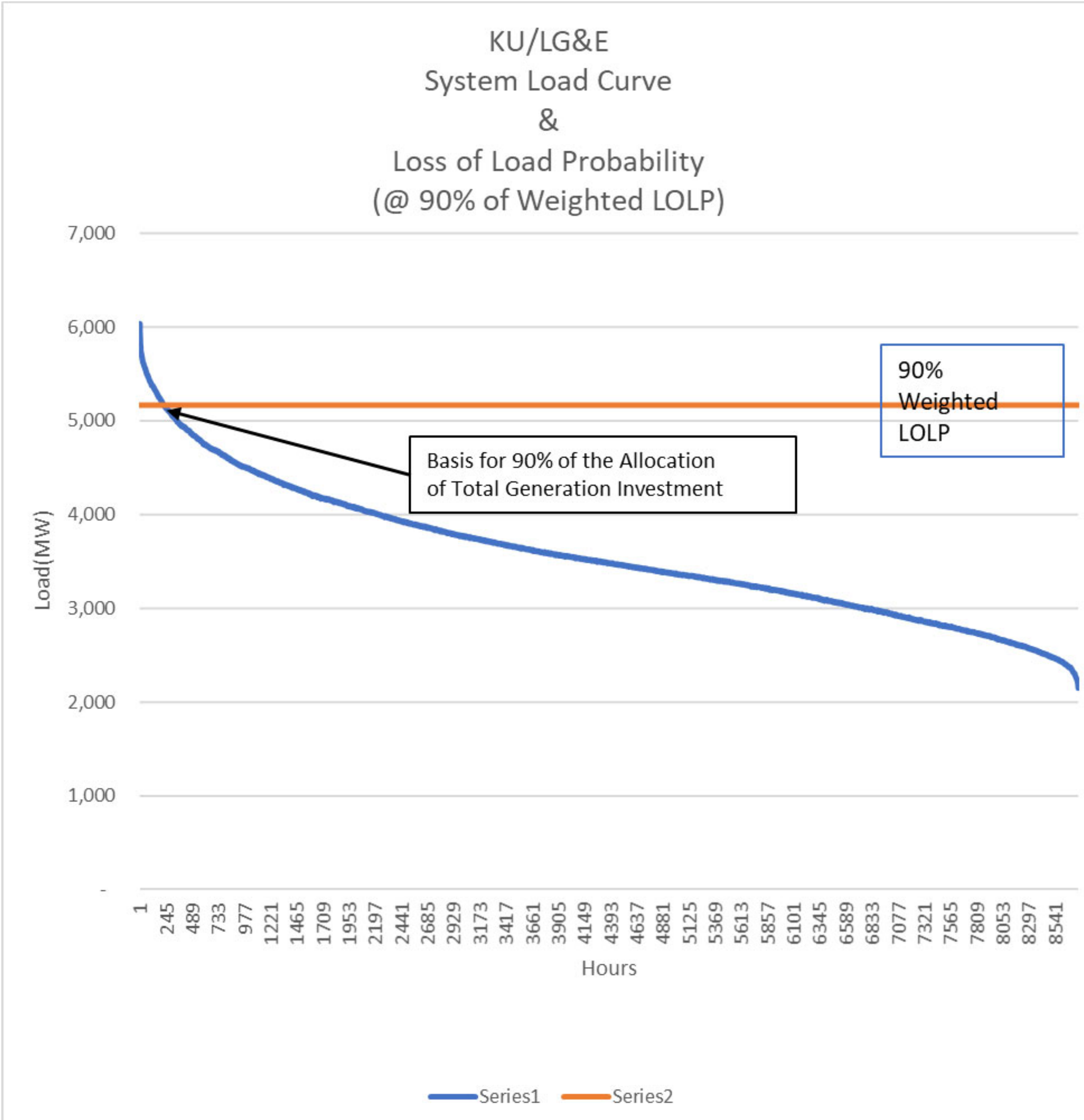
Unit	Capacity MW[18]	Hour[17] 1300	1400	1500	1600
Mill Creek 2	356	0	0	0	0
Brown 5	123	68	30	0	66
Brown 8	126	50	27	0	0
Brown 9	126	50	27	0	0
Brown 10	126	0	0	27	0
Brown 11	126	0	0	27	0
Haefling	42	0	0	0	0
Paddy's Run 12	33	0	0	0	0
Trimble 8	199	0	0	0	139
Trimble 10	199	0	0	0	0
Zorn 1	18	0	0	0	0
Curtailments	127 [19]	0	0	0	0

[16] In response to AG-KIUC 1-121, the Companies indicated that there is 127 MW of load subject to curtailment.
[17] Per response to AG-KIUC 1-117.
[18] Per response to AG-KIUC 1-126.
[19] Per response to AG-KIUC 1-121.

Remembering that the forecasted maximum unserved load is only 8.3 MW, if any one of the above units were dispatched or operated with a tiny bit more output, this in itself would negate any LOLPs.

Q. WITH THESE UNDERSTANDINGS, CAN YOU SHOW HOW MR. SEELYE HAS ALLOCATED ALL OF THE BASE, INTERMEDIATE, AND PEAKER GENERATION-RELATED COSTS?

A. Yes. As noted earlier, the vast majority of hours in the test year have calculated LOLPs of essentially zero. The hours that do have a calculated positive LOLP are few in number and represent those highest annual system peak loads. The following graph shows that 90% of Mr. Seelye's generation allocation factors only consider loads during the highest peak periods even though it has been established that the vast majority of the Companies' investment in generation facilities is ascribed to base load units that were planned, designed and are utilized to serve customers' loads throughout the year.



So that it is clear, 90% of Mr. Seelye's allocation factor is based on a few Summer afternoon peak hours of the year wherein class contributions to these few peak hours are then used to allocate <u>all</u> generation-related costs.

Q. IS MR. SEELYE'S APPROACH APPROPRIATE FOR KU AND LG&E?

A. No. As discussed and proven earlier, the Companies entire LOLP analysis is unrealistic and even flawed from a mathematical standpoint; i.e., when non-firm load is subtracted from total load, we see that there is not a single hour that has a positive LOLP or corresponding probability of unserved load. Furthermore, Mr. Seelye's method to assign generation-related costs to individual classes gives no consideration to the manner in which the Companies' combined generation resources were planned, designed, or installed. As a result, his analysis does not reasonably reflect the manner in which the Companies' generation costs are incurred. In turn, Mr. Seelye's approach over-assigns costs to those classes that contribute relatively more to a few peak hours of the year than they do during other periods of the year.

Q. DOES THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC") RECOGNIZE LOLP AS A METHOD FOR ALLOCATING GENERATION-RELATED COSTS WITHIN CLASS COST ALLOCATION STUDIES?

A. Yes. The NARUC <u>Electric Utility Cost Allocation Manual</u> does include the LOLP as a recognized method to allocate generation costs across classes.

Q. DO MR. SEELYE'S LOLP APPROACH AND STUDIES COMPORT WITH THE LOLP METHODOLOGY SET FORTH IN THE NARUC MANUAL?

A. No. Nothwithstnading the fact that there is not a single hour with a loss of load probability, Mr. Seelye's approach is far from complying with the methodology set forth in the NARUC Manual. The NARUC Manual states that the LOLP method should be conducted as follows:

> Using the LOLP production cost method, **hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values**. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occuring in each. **Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above.** This method requires detailed analysis of hourly LOLP values and a significant data manupulation effort. (page 62) [Emphasis added]

With regard to assigning costs to the three rating periods, the NARUC Manual explains the prescribed approach under the Base-Intermediate-Peak ("BIP") method as follows:

> **The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components**. **In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only**.
>
> There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period. (pp. 60-61) [Emphasis added]

As described above, the NARUC-prescribed LOLP method is based on the cost causation principles discussed earlier wherein proper consideration is given to investment costs devoted to serving base, intermediate, and peak load requirements. This is in stark contrast to Mr. Seelye's approach wherein he has effectively allocated virtually all of the Companies' total generation costs simply on peak period demands.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. SEELYE'S PROPOSED CLASS COST OF SERVICE STUDY IN THIS CASE?

A. Mr. Seelye's electric cost of service studies should be rejected in their entirety. First, it is inconceivable that KU and LG&E cannot meet their native firm load requirements each and every hour of the year given the extraordinary amount of excess capacity that exists within the system. Second, even if the Companies' assumptions that went into its LOLP analysis were accepted, the Companies' erred in including non-firm loads within their LOLP analyses and when non-firm load is properly considered within the Companies' LOLP calculations, we find that there is not a single hour in which KU and LG&E cannot meet their firm load requirements. Third, the Companies forecasted hourly dispatch of its generating units is unrealistic in that numerous units are offline during those hours that a LOLP is calculated. Finally, his proposed LOLP method does not comport with the NARUC Electric Utility Cost Allocation Manual in which recognition is to be given to how generation resources are utilized during all periods of the year, and is contrary to cost causation generally and how costs are specifically incurred by KU and LG&E.

Q. DID MR. SEELYE CONDUCT ALTERNATIVE CCOSS UTILIZING DIFFERENT GENERATION ALLOCATION METHODOLOGIES?

A. Yes. In compliance with the Settlement Agreement and Commission Order in the last general rate case (Case Nos. 2018-00294 and 2018-00295), Mr. Seelye also calculated KU and LG&E CCOSS utilizing the 6-CP and 12-CP approaches.

Q. ARE MR. SEELYE'S ALTERNATIVE CCOSS UTILZING THE 6-CP AND 12-CP METHODS TO ALLOCATE GENERATION PLANT REASONABLE AND APPROPRIATE FOR KU AND LG&E?

A. No. As discussed and explained in detail earlier in my testimony, KU's and LG&E's portfolio of generation assets is comprised predominately of base load units that were planned and operate throughout the year in order to minimize energy costs. Furthermore, even though the Companies currently have a tremendous amount of excess capacity, ratepayers are required to compensate the Companies for its total generation plant investment. The 6-CP and 12-CP methods allocate the Companies total generation costs to classes based on the highest system peak demands during each of the highest six months of system load (6-CP) and based on the highest system peak demands during each month (12-CP). If one were to consider either the 6-CP or 12-CP approaches, the residential and small commercial classes would be assigned a *disproportionately* large amount of the Companies' generation plant investment simply because these classes drive the system peaks. However, this in no way reflects how the Companies' portfolio of generation plant was planned, installed, or is operated.

Q. PLEASE PROVIDE A SUMMARY OF CLASS RATES OF RETURN UNDER MR. SEELYE'S PREFERRED AND ALTERNATIVE CCOSS.

A. Although Mr. Seelye recommends his CCOSS utilizing his LOLP approach, he also conducted studies that allocate generation plant based on 6-CP and 12-CP demands. The table below provides a summary of Mr. Seelye's CCOSS results at current rates:

TABLE 4
Kentucky Utilities
Seelye CCOSS Results (RORs At Current Rates)

Class	LOLP	6-CP	12-CP
Rate RS	2.67%	2.14%	2.52%
Rate GS	11.05%	11.21%	11.32%
Rate AES	5.89%	3.68%	3.17%
Rate PS – Secondary	9.95%	10.05%	9.70%
Rate PS – Primary	17.91%	18.99%	19.00%
Rate TOD – Secondary	3.95%	4.68%	3.93%
Rate TOD – Primary	3.20%	4.26%	3.78%
Rate RTS	3.53%	4.65%	3.54%
Rate FLS	2.75%	5.40%	4.98%
Rate LS & RLS	12.32%	10.54%	10.41%
Rate LE	28.05%	10.03%	9.27%
Rate TE	12.39%	13.18%	12.34%
Rate OSL	30.32%	30.28%	30.27%
Rate EV	-27.00%	-27.07%	-27.07%
Rate SSP	-1.31%	-1.31%	-1.31%
Rate BS	4.80%	4.80%	4.80%
Total KU	4.81%	4.81%	4.81%

TABLE 5
Louisville Gas & Electric – Electric Operations
Seelye CCOSS Results (RORs At Current Rates)

Class	LOLP	6-CP	12-CP
Rate RS	0.60%	1.33%	1.75%
Rate GS	10.96%	9.67%	9.98%
Rate PS – Primary	14.43%	12.67%	11.72%
Rate PS – Secondary	10.30%	8.93%	8.50%
Rate TOD – Primary	6.45%	6.02%	5.04%
Rate TOD – Secondary	5.33%	4.44%	3.96%
Rate RTS	7.23%	5.76%	3.75%
Special Contract	5.52%	3.29%	2.44%
Rate RLS & LS	9.74%	8.02%	7.79%
Rate LE	31.88%	9.82%	8.24%
Rate TE	15.01%	13.90%	11.82%
Rate OSL	89.10%	92.63%	92.28%
Rate EV	-27.07%	-27.10%	-27.08%
Rate SSP	3.60%	3.60%	3.60%
Rate BS	-4.38%	-4.38%	-4.38%
Total LG&E	4.34%	4.34%	4.34%

4. Alternative Generation Allocation Methods

Q. HAVE YOU CONDUCTED ALTERNATIVE STUDIES THAT MORE ACCURATELY REPRESENT THE CAPACITY AND ENERGY TRADE-OFFS EXHIBITED IN KU'S GENERATION PLANT INVESTMENT?

A. Yes. Although there is no single, or absolute, correct method to allocate joint generation costs, some methods are in fact superior to others. That is, in evaluating generation cost responsibility, it is paramount to recognize the portfolio of generating assets included in rate base which in turn, serves all customers in a joint manner. There is no doubt that the vast majority of KU's and LG&E's investment in generation assets is comprised of base load units that serve customers' loads throughout the year wherein intermediate and peaker units comprise a much smaller percentage of the Companies' generation investment and are utilized to a much lesser extent. These realities need to be incorporated in the Companies' CCOSS in order to properly and reasonably reflect cost causation across classes.

In my opinion, the Probability of Dispatch and BIP methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. This is particularly true and important for KU and LG&E given the fact that the preponderance of its investment in generation plant is associated with base load generation facilities.[20] As such, I have conducted alternative CCOSS utilizing these two allocation methodologies.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR ALTERNATIVE CCOSS.

A. In compliance with the Commission's prior directive for all CCOSS to incorporate and show the functionalization, classification and allocation of all costs,[21] I have developed my model to reflect the assignment of costs to each of these three costing categories. The presentation of my model results differs from that of Mr. Seelye's in that I show the functionalization, classification and allocation of costs individually for every FERC account (rate base and expenses). Mr. Seelye's model aggregates costs within his

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[20] It is recognized that KU and LG&E jointly dispatch their combined generating assets based on the system load of both utilities. As such, my analyses (as well as Mr. Seeyle's) reflects this joint dispatch of generating assets.

[21] Case No. 2013-00148, Final Order, page 35, April 22, 2014.

classification process such that his output does not show the allocation by individual FERC account.

Furthermore, Mr. Seelye did not fully allocate costs to the Electric Vehicle Charging (Rate EV), Solar Share (Rate SSP) and Business Solar (Rate BS) rate schedules in that he directly-assigned certain capital investments and a few O&M costs to these rate schedules. I do not take issue with Mr. Seelye's treatment for these three classes at this time, and have therefore, accepted his allocation of costs to these rate schedules. It should be noted that the rate base and O&M costs associated with these classes are *de minimis* in terms of total KU or total LG&E.

Finally, Mr. Seelye allocated fuel inventory (part of working capital) based on his LOLP allocator. Fuel inventory is a function of the amount of fuel that will be burned to generate electricity, and is therefore, more appropriately allocated based on energy as opposed to any measure of peak demand. This has a very minor impact on CCOSS results.

a. Probability of Dispatch Method

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, KU and LG&E provided both of these critical data sets. As such, I was able to conduct a CCOSS utilizing the Probability of Dispatch method.

In developing my Probability of Dispatch method, I was initially uncertain as to whether to use actual historical or forecasted hourly loads and generation output by unit. That is, while all other aspects of Mr. Seelye's CCOSS are based on forecasted test year amounts, I have observed unrealistic assumptions relating to the dispatch of generating units during the forecast period. At the same time, I did not want to rely solely on historical data in developing probability of dispatch allocators due to the Companies utilization of a forecasted test year. Therefore, I conducted my Probability of Dispatch analyses both on a historical and forecasted basis.

The first step in conducting the Probability of Dispatch method was to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the NARUC: Electric Utility Cost Allocation Manual,[22] each plant's total gross investment, accumulated depreciation and depreciation expense was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour. My Schedules GAW-3 through GAW-5 provides sample pages of these hourly assignments for KU and LG&E for the forecast period.[23] It should be noted that the same procedures were performed for the historic period and due to voluminous nature of this analysis, a sample of the historic period is not provided in my schedules but are contained in their entirety in their filed workpapers.

Once I determined total hourly capital costs (gross plant, depreciation reserve and depreciation expense), I was able to assign these costs to individual rate classes on an hour-by-hour basis. As indicated earlier, the Companies provided individual class loads for each hour. I then multiplied each class' hourly percentage contribution to the total (adjusted for line losses) jurisdictional retail load by the hourly generation investment cost for each hour of the year. In order to develop class responsibility for KU's and LG&E's net generation plant and depreciation expense, I then summed hourly class investment and depreciation costs for all hours of the year to obtain annual amounts by class for gross plant, depreciation reserve, and depreciation expense. My Schedules GAW-6 through GAW-8 provides sample pages of the hourly assignment of generation costs (gross plant, depreciation reserve, and depreciation expense) to individual rate classes for the forecast period. It should be noted that the same procedures were performed for the historic period and due to voluminous nature of this analysis, a sample of the historic period is not provided in my schedules but are contained in their entirety in their filed workpapers.

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[22] 1992 Edition, page 62.

[23] It should be noted that this exercise actually assigns costs to every hour of the year. My filed workpapers contain the details of this assignment for every hour.

Q. EARLIER IN YOUR TESTIMONY, YOU INDICATED THAT THE PROBABILITY OF DISPATCH AND BASE-INTERMEDIATE-PEAK METHODS MAY NOT PROPERLY RECOGNIZE CLASS VARIANCES IN VARIABLE GENERATION COSTS. HAVE YOU EXAMINED IF THERE ARE MATERIAL DIFFERENCES IN CLASS FUEL COSTS WHEN ANALYZED ON AN HOURLY (TIME DIFFERENTIATED) BASIS?

A. Yes. As discussed earlier, the Companies provided each generation plant's hourly output. In addition, in response to AG-KIUC 1-129 and AG-KIUC 1-130, the Companies provided monthly fuel costs (per kWh) for each plant. With this data, I was able to calculate hourly fuel costs by individual generating plant based on each unit's hourly output. I then assigned these hourly fuel costs to individual rate classes on an hour-by-hour basis based on the class hourly loads previously discussed.[24] The result of this analysis yielded similar hourly fuel costs for all classes. Because hourly fuel costs were assigned to each class based on hourly loads at generation (in order to reflect line losses), I then calculated each class' average fuel cost mWh at the meter. The table below provides each class and sub-classes' time differentiated fuel cost (per mWh) at the meter.[25]

TABLE 6
KU Time Differentiated Fuel Costs
Per mWh At Meter

Rate Schedule	Historic Fuel Cost Per mWh	Forecasted Fuel Cost Per mWh
Rate RS	$24.21	$23.96
Rate GS	$24.11	$23.90
Rate AES	$24.23	$23.93
Rate PS – Secondary	$24.04	$23.86
Rate PS – Primary	$23.39	$23.23
Rate TOD – Secondary	$23.95	$23.80
Rate TOD – Primary	$23.29	$23.12
Rate RTS	$22.85	$22.64
Rate FLS	$22.77	$22.57
Rate LS & RLS	$23.08	$23.24
Rate LE	$23.08	$23.24
Rate TE	$23.77	$23.65
Rate OSL	$24.10	$23.69
TOTAL KU	$23.78	$23.57

[24] Class hourly loads were measured at the generation level in order to reflect losses by voltage level.
[25] The details of this analysis are provided in my filed workpapers.

TABLE 7
LG&E Time Differentiated Fuel Costs
Per mWh At Meter

Rate Schedule	Historic Fuel Cost Per mWh	Forecasted Fuel Cost Per mWh
Rate RS	$23.58	$23.43
Rate GS	$23.53	$23.35
Rate PS – Primary	$22.86	$22.75
Rate PS – Secondary	$23.50	$23.32
Rate TOD – Primary	$22.79	$22.65
Rate TOD – Secondary	$23.41	$23.27
Rate RTS	$22.37	$22.19
Special Contract	$22.72	$22.62
Rate RLS & LS	$22.58	$22.74
Rate LE	$22.58	$22.74
Rate TE	$23.25	$23.13
Rate OSL	$23.42	$23.07
Total LG&E	$23.29	$23.12

In examining these time differentiated fuel costs by class and voltage level, the results are generally consistent with expectations such that secondary voltage fuel costs at the meter tend to be somewhat higher than for primary voltage, which then tend to be somewhat higher than those for transmission customers.

In conclusion, and as shown in Tables 6 and 7 above, there is not much difference in average per unit fuel costs on a time differentiated basis even when voltage losses are considered.

Q. HAVE YOU INCORPORATED TIME DIFFERENTIATED FUEL COSTS WITHIN YOUR PROBABILITY OF DISPATCH CCOSS?

A. Yes. Because fixed generation capacity costs are evaluated on an hour-by-hour basis, it is also appropriate to evaluate variable fuel costs on an hour-by-hour basis.

Q. PLEASE EXPLAIN YOUR SECOND PROBABILITY OF DISPATCH APPROACH IN WHICH YOU WEIGHTED FIXED GENERATION CAPACITY COSTS BASED ON HOURLY WHOLESALE MARKET VALUES.

A. Some analysts have criticized the NARUC Probability of Dispatch method in that even though this approach assigns generation capacity costs on an hour-by-hour basis based on how each generation unit is utilized, it does not recognize that wholesale market prices tend to be higher during periods of high demand and lower during periods of low demand. I do not entirely agree with this criticism because if performed properly, more units (with higher total assigned generation costs) are operated during periods of high demand, and therefore, those high demand hours are assigned more generation costs than during low demand hours.

Nonetheless, I have also conducted the Probability of Dispatch recognizing wholesale market prices. Specifically, I weighted each hour's assigned generation capacity cost by the corresponding wholesale hourly market prices.[26]

Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE PROBABILITY OF DISPATCH METHODS.

A. The following table provides a comparison of class rates of return ("RORs") at current rates under both Probability of Dispatch methods. In this regard, it should be noted that the tables below utilize the same distribution customer/demand split as used by Mr. Seelye in his CCOSS. Later in my testimony, I will incorporate my recommended changes to the classification and allocation of distribution costs.

[26] Per response to AG-KIUC 1-119 and AG-KIUC 1-120.

TABLE 8
Kentucky Utilities
Probability of Dispatch Results
RORs at Current Rates
(Utilizing Seelye Distribution Customer/Demand Classification)

	Historic		Forecasted		
Rate Schedule	Pro-Rata Allocation	Market-Based Allocation	Pro-Rata Allocation	Market-Based Allocation	Average
Rate RS	3.82%	3.57%	3.98%	3.71%	3.77%
Rate GS	12.11%	12.02%	12.40%	12.31%	12.21%
Rate AES	5.23%	5.12%	5.26%	5.20%	5.20%
Rate PS – Secondary	9.78%	9.84%	10.36%	10.46%	10.11%
Rate PS – Primary	6.18%	6.38%	17.75%	17.98%	12.07%
Rate TOD – Secondary	4.06%	4.26%	3.33%	3.50%	3.79%
Rate TOD – Primary	1.52%	1.82%	0.98%	1.30%	1.41%
Rate RTS	0.15%	0.42%	0.47%	0.77%	0.45%
Rate FLS	1.04%	1.48%	-0.20%	0.17%	0.62%
Rate LS & RLS	9.53%	9.97%	9.35%	9.73%	9.65%
Rate LE	6.04%	7.69%	2.02%	3.17%	4.73%
Rate TE	10.62%	11.18%	8.46%	8.92%	9.80%
Rate OSL	24.43%	24.45%	25.73%	25.81%	25.11%
Rate EV	-27.00%	-27.00%	-27.00%	-27.00%	-27.00%
Rate SSP	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Rate BS	4.80%	4.80%	4.80%	4.80%	4.80%
Total KU	4.81%	4.81%	4.81%	4.81%	4.81%

TABLE 9
Louisville Gas & Electric
Probability of Dispatch Results
RORs at Current Rates
(Utilizing Seelye Distribution Customer/Demand Classification)

	Historic		Forecasted		
Rate Schedule	Pro-Rata Allocation	Market-Based Allocation	Pro-Rata Allocation	Market-Based Allocation	Average
Rate RS	2.65%	2.42%	2.89%	2.67%	2.66%
Rate GS	11.18%	11.11%	11.68%	11.62%	11.40%
Rate PS – Primary	14.01%	14.39%	11.02%	11.27%	12.67%
Rate PS – Secondary	7.99%	8.03%	9.03%	9.10%	8.54%
Rate TOD – Primary	1.62%	2.01%	1.50%	1.89%	1.76%
Rate TOD – Secondary	4.50%	4.71%	3.07%	3.21%	3.87%
Rate RTS	1.37%	1.84%	-0.06%	0.37%	0.88%
Special Contract	-0.70%	-0.25%	-0.94%	-0.61%	-0.62%
Rate RLS & LS	6.49%	6.89%	6.27%	6.55%	6.55%
Rate LE	-0.22%	1.12%	-0.98%	-0.12%	-0.05%
Rate TE	7.29%	7.88%	7.21%	7.71%	7.52%
Rate OSL	55.54%	54.60%	81.45%	81.40%	68.25%
Rate EV	-27.07%	-27.07%	-27.07%	-27.07%	-27.07%
Rate SSP	3.60%	3.60%	3.60%	3.60%	3.60%
Rate BS	-4.38%	-4.38%	-4.38%	-4.38%	-4.38%
Total LG&E	4.34%	4.34%	4.34%	4.34%	4.34%

Summaries of my Probability of Dispatch methods are provided in my Schedules GAW-9 through Schedule GAW-16 while the details are contained in my filed workpapers.

b. Base-Intermediate-Peak ("BIP") Method

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. In order to reflect the capacity/energy trade-off inherent in the Companies' mix of generating resources, each plant's owned capacity (mW) and output (mWh) is required.[27] Schedule GAW-17 provides the classification between energy and demand for the Companies' combined generation plant under the BIP method. The BIP method evaluates each plant based on its variable fuel costs, order of dispatch and capacity factor to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements.

Q. DOES SCHEDULE GAW-17 HELP EXPLAIN THE CAPACITY/ENERGY TRADE-OFF CONSIDERATION USED BY ELECTRIC UTILITIES IN DEVELOPING A PARTICULAR MIX OF GENERATING FACILITIES?

A. Yes. As can be seen in Schedule GAW-17, the Companies' larger, more expensive, generating plants have high capacity factors and lower fuel costs. These large base load units run most hours of the year supplying energy to all customers. In contrast, the smaller, high operating (fuel) cost plants tend to have lower capacity factors meaning they are primarily used to meet peak loads. Because the vast preponderance of the Companies' investment in generation plant is associated with its base load units, a very large percentage (86.51%) of generation plant is classified as energy-related under the BIP method.

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[27] KU and LG&E own 75% of Trimble Unit 1 and Trimble Unit 2 wherein a non-affiliate owns the remaining 25% of these units. As such, the available capacity (mW) and energy output (mWh) reflects KU's and LG&E's 75% entitlement.

Q. IN CONDUCTING YOUR CCOSS UTILIZING THE BIP METHOD TO ALLOCATE GENERATION COSTS, DID YOU ALSO INCORPORATE TIME DIFFERENTIATED FUEL COSTS IN THESE STUDIES?

A. Yes.

Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. The following table provides a summary of class RORs under the BIP method recognizing that the distribution Customer/Demand classification and allocation is the same as used by Mr. Seelye in conducting his CCOSS analysis:

TABLE 10
KU
Class RORs at Current Rates
Customer/Demand
(BIP Method)

Rate Schedule	ROR
Rate RS	3.83%
Rate GS	12.20%
Rate AES	5.04%
Rate PS – Secondary	10.18%
Rate PS – Primary	18.18%
Rate TOD – Secondary	3.48%
Rate TOD – Primary	1.16%
Rate RTS	0.68%
Rate FLS	0.42%
Rate LS & RLS	9.67%
Rate LE	2.89%
Rate TE	8.87%
Rate OSL	26.26%
Rate EV	-27.00%
Rate SSP	-1.31%
Rate BS	4.80%
Total KU	4.81%

TABLE 11
LG&E
Class RORs at Current Rates
Customer/Demand
(BIP Method)

Rate Schedule	ROR
Rate RS	2.65%
Rate GS	11.42%
Rate PS – Primary	11.37%
Rate PS – Secondary	9.08%
Rate TOD – Primary	1.82%
Rate TOD – Secondary	3.38%
Rate RTS	0.51%
Special Contract	-0.13%
Rate RLS & LS	6.73%
Rate LE	0.35%
Rate TE	8.12%
Rate OSL	81.33%
Rate EV	-27.07%
Rate SSP	3.60%
Rate BS	-4.38%
Total LG&E	4.34%

A summary of results under the BIP method (utilizing Mr. Seelye's distribution Customer/Demand classification) is provided in my Schedule GAW-18 and Schedule GAW-19. Furthermore, for informational purposes, the functionalizations and classifications under the BIP method are provided in my Schedule GAW-20 and Schedule GAW-21 and the detailed class allocations are provided in my Schedule GAW-22 and Schedule GAW-23. In this regard, the format of the functionalization/ classification and class allocations are identical for all of my alternative electric CCOSS.

c. <u>Conclusions Concerning the Allocation of Generation Plant</u>

Q. PLEASE PROVIDE A COMPARISON OF MR. SEELYE'S RECOMMENDED LOLP GENERATION ALLOCATION APPROACH TO THOSE OBTAINED UNDER THE PROBABILITY OF PEAK AND BIP METHODS.

A. The following table provides a comparison of class RORs at current rates under each of these methods. In this regard, it should be understood that the Probability of Dispatch and BIP results also utilize the same distribution plant classification as that used by Mr. Seelye:

TABLE 12
KU
CCOSS Comparison
ROR @ Current Rates
(Using Seelye Distribution Customer/Demand Classification)

Rate Schedule	Seelye LOLP	Probability of Dispatch (Average)	BIP
Rate RS	2.67%	3.77%	3.83%
Rate GS	11.05%	12.21%	12.20%
Rate AES	5.89%	5.20%	5.04%
Rate PS – Secondary	9.95%	10.11%	10.18%
Rate PS – Primary	17.91%	12.07%	18.18%
Rate TOD – Secondary	3.95%	3.79%	3.48%
Rate TOD – Primary	3.20%	1.41%	1.16%
Rate RTS	3.53%	0.45%	0.68%
Rate FLS	2.75%	0.62%	0.42%
Rate LS & RLS	12.32%	9.65%	9.67%
Rate LE	28.05%	4.73%	2.89%
Rate TE	12.39%	9.80%	8.87%
Rate OSL	30.32%	25.11%	26.26%
Rate EV	-27.00%	-27.00%	-27.00%
Rate SSP	-1.31%	-1.31%	-1.31%
Rate BS	4.80%	4.80%	4.80%
Total KU	4.81%	4.81%	4.81%

TABLE 13
LG&E
CCOSS Comparison
ROR @ Current Rates
(Using Seelye Distribution Customer/Demand Classification)

Rate Schedule	Seelye LOLP	Probability of Dispatch (Average)	BIP
Rate RS	0.60%	2.66%	2.65%
Rate GS	10.96%	11.40%	11.42%
Rate PS – Primary	14.43%	12.67%	11.37%
Rate PS – Secondary	10.30%	8.54%	9.08%
Rate TOD – Primary	6.45%	1.76%	1.82%
Rate TOD – Secondary	5.33%	3.87%	3.38%
Rate RTS	7.23%	0.88%	0.51%
Special Contract	5.52%	-0.62%	-0.13%
Rate RLS & LS	9.74%	6.55%	6.73%
Rate LE	31.88%	-0.05%	0.35%
Rate TE	15.01%	7.52%	8.12%
Rate OSL	89.10%	68.25%	81.33%
Rate EV	-27.07%	-27.07%	-27.07%
Rate SSP	3.60%	3.60%	3.60%
Rate BS	-4.38%	-4.38%	-4.38%
Total LG&E	4.34%	4.34%	4.34%

As can be seen in the tables above, there are material differences for some classes and minimal differences for other classes.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PROPER ALLOCATION OF KU'S GENERATION PLANT?

A. KU's and LG&E's combined portfolio of generating assets is comprised predominately of large base load units that serve the energy needs of KU and LG&E throughout the entire year. While the Companies do indeed rely upon intermediate and peaker units to some degree, the dollar investment in these facilities pale in comparison to its base load investments. Based on these realities, it is clear that the Companies have not planned, and do not operate, their portfolio of generating assets simply to meet peak demands, but rather, this portfolio of generation assets was planned, and is operated, in order to minimize total costs; i.e., capacity and energy costs. The Probability of Dispatch and BIP methods are very detailed approaches that are theoretically sound and reasonably reflect the capacity/energy trade-off in generation facilities specific to the Companies' investments. As such, these two methods are the most "accurate" methods from a cost causation perspective. It is my opinion that each of these methods should be considered in evaluating class profitability. Furthermore, Mr. Seelye's LOLP analysis is so flawed that it cannot be relied upon for evaluating class revenue responsibility.

5. <u>Distribution Plant</u>

Q. PLEASE EXPLAIN THE PHRASE "CLASSIFICATION OF DISTRIBUTION PLANT."

A. It is generally recognized that there are no energy-related costs associated with distribution plant. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility distribution plant sometimes is classified as partially demand-related and partially customer-related.

Q. WHY IS DISTRIBUTION PLANT SOMETIMES CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Even though investment is made in distribution plant and equipment to meet the needs of customers at their required power levels, there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. Therefore, if one were to allocate distribution plant investment based simply on class contributions to peak demand, an inequitable allocation of these costs may result.

As a hypothetical, suppose a utility serves both an urban area and a rural area. In this situation, many customers' electrical needs are served with relatively few miles of conductors, few poles, etc. in the urban area, while many more miles of conductors, more poles, etc. are required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that commercial and industrial customers are predominately clustered in the more densely populated urban area, while the less dense (rural) portion of the service territory consists almost entirely of residential customers, it may be unreasonable to allocate the total Company's distribution investments based solely on demand; i.e., a large investment in many miles of line is required to serve predominately residential customers in the rural area while the commercial and industrial electrical needs are met with much fewer miles of lines in the urban area. Under this circumstance, an allocation of costs based on a weighting of customers and demand can be considered equitable and appropriate.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THE CONCEPTS OF DENSITY AND CLASS CUSTOMER MIX AS THEY RELATE TO COST ALLOCATIONS.

A. As a starting point, it is important to understand absolute and relative class relationships of an electric utility's number of customers, energy requirements, and maximum loads (demands). In terms of simple customer counts, the number of residential accounts make-up the majority of any retail electric utility's number of customers. However, because residential customers tend to be small volume users compared to commercial and industrial customers, the residential class is responsible for a significantly smaller percentage of total kWh energy supplied or peak loads on the system. For example, in KU's system, the following characteristics are exhibited:

TABLE 14

	KU Percentage of Total Jurisdictional Distribution System[28]		
Category	Customers	kWh	Peak Demand (NCP)
Residential	83.3%	38.9%	48.7%
Comm./Ind. Distribution Voltage	16.7%	61.1%	51.3%

While the table above shows the relative class differences between number of customers, energy usage, and peak demands, the following table illustrates the absolute size differences between KU's different types of customers:

TABLE 15

Category	KU Average Annual kWh Per Customer (kWh)
Residential	13,437
Comm./Ind. Distribution Voltage	86,061

With the above relationships explained, in order to understand the concepts of density and class customer mix, consider examples of two hypothetical electric utilities each of which are comprised of only two distribution lines: one line serving a densely populated area (urban) and another line serving a sparsely populated area (rural). Furthermore, for simplicity and explanatory purposes, assume there are only two classes of customers for each utility: Residential and Commercial/Industrial with the following characteristics:

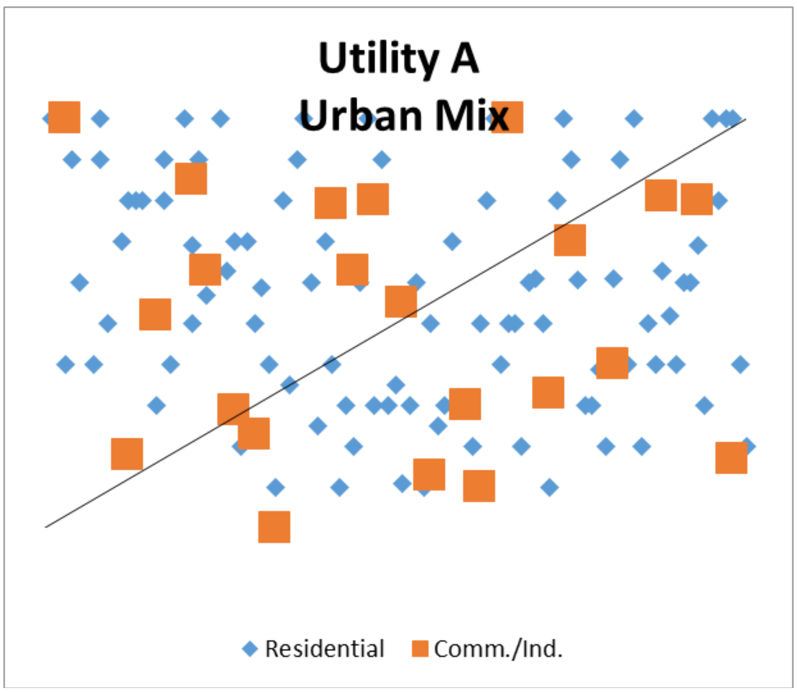
[28] Excludes transmission, lighting and EV classes.

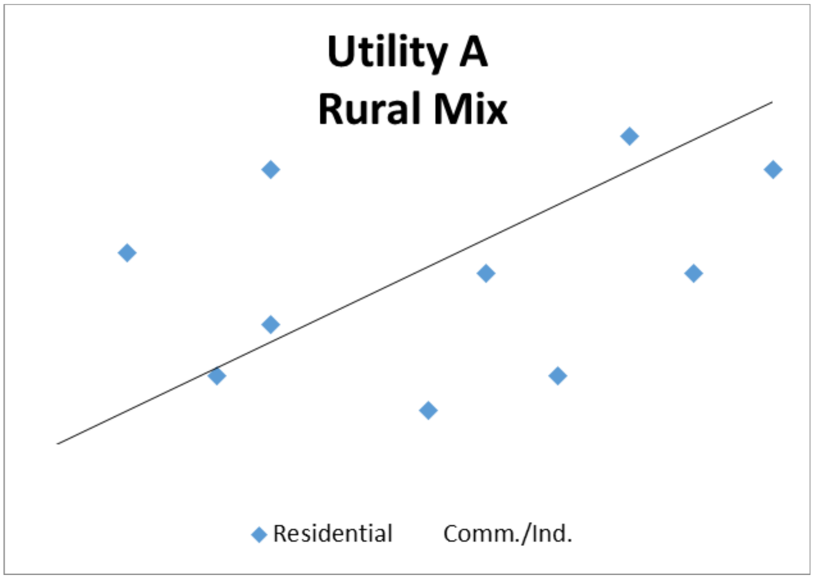
TABLE 16

	Absolute			Relative	
Class	Number of Customers	Peak Load	Peak Load Per Customer	Number of Customers	Peak Load
Residential	110	550	5	83%	33%
Comm./Ind.	22	1,100	50	17%	67%
Total	132	1,650	--	100%	100%

Utility A:

For Utility A, assume all commercial/industrial customers are located on the urban (densely populated) distribution line such that the rural line only serves residential customers as shown graphically below:





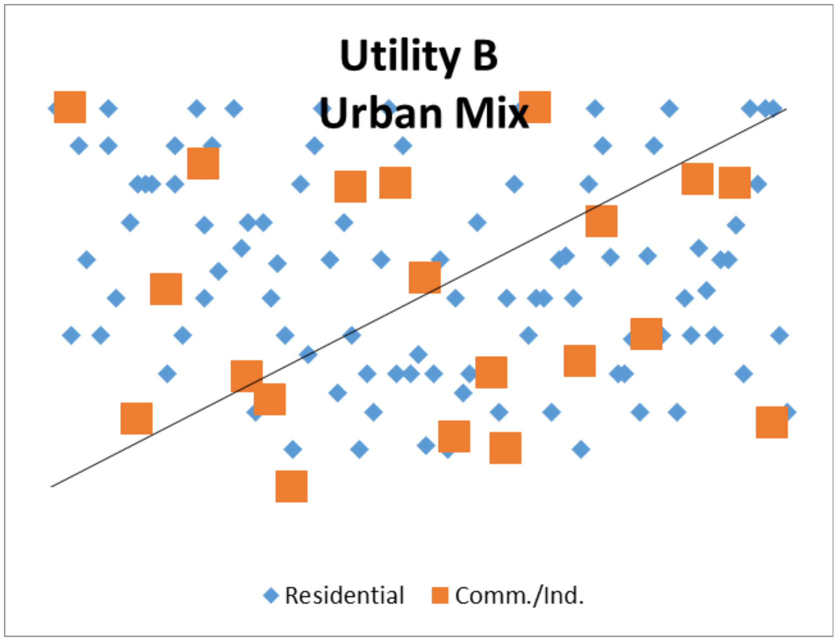
Because the urban line is much shorter in total distance, yet, serves the majority of customers (and loads) <u>and</u> many more miles of line are required to serve relatively few residential only customers in rural areas, it would be unfair, and inconsistent with cost causation to allocate total system line costs only on utilization (kW) because commercial/industrial customers arguably do not cause costs to be incurred for the rural portion of the system. As such, some weighting of relative number of customers and utilization is appropriate to allocate total system line costs.

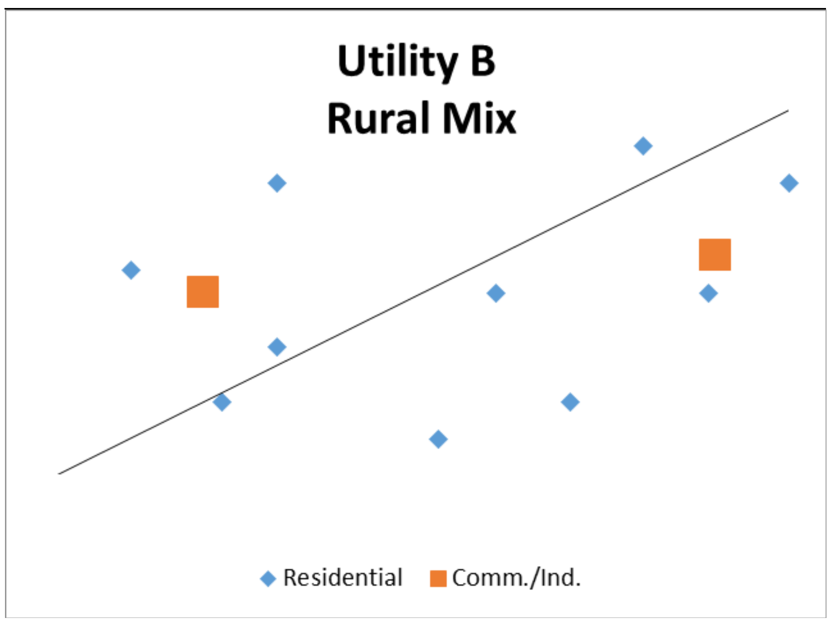
<u>Utility B</u>:

For Utility B, assume that the relative mix of customers is evenly distributed between the urban and rural lines. In other words, this utility's configuration of customers is as follows:

TABLE 17

	Number of Customers			
	Urban Line		Rural Line	
Class	Amount	Percent	Amount	Percent
Residential	100	83%	10	83%
Comm./Ind.	20	17%	2	17%
Total	120	100%	12	100%





As can be seen in the above table and charts, the relative imposition of costs across the two classes for Utility B is the same for the urban and rural lines. That is, while there are more absolute residential customers than commercial/industrial customers on both the urban and rural lines, the proportion (mix) of customers is the same between urban and rural. As such, an allocation of total system lines costs based on utilization (maximum loads) is appropriate such that no consideration of customer counts is needed or desired. Indeed, if distribution costs are classified and allocated partially on number of customers, the Residential class will be over burdened with cost responsibility creating a subsidy for commercial/industrial customers.

Q. DOES THE CLASSIFICATION OF DISTRIBUTION PLANT INVESTMENT AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED REFLECT ANY RELATIVE COST (PER MILE) DIFFERENCES BETWEEN URBAN AND RURAL AREAS?

A. No. It is generally more expensive to install a mile of distribution circuit in an urban area than in a rural area. However, although this cost difference may be substantial, this cost difference is usually ignored due to record keeping limitations, in that all costs are simply assumed to be uniform (averaged) across the rural and urban portions of a service area.

Q. DO YOUR EXAMPLES DISCUSSED ABOVE IMPLY THAT IT COSTS MORE TO SERVE RURAL CUSTOMERS THAN URBAN CUSTOMERS AND THAT PERHAPS A UTILITY'S RURAL CUSTOMERS SHOULD PAY MORE PER UNIT THAN URBAN CUSTOMERS?

A. While it is possible that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has generally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences. Rather, regulatory policy has been such that classes of customers with similar usage and/or load characteristics are established for pricing purposes. In fact, during my 40 years practicing utility costing and pricing across the Country, I have never seen an electric rate structure that discriminates based on customer densities or other geographic characteristics.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR EXPLANATION AND CONCEPTS REGARDING CUSTOMER DENSITIES AND CLASS CUSTOMER MIXES?

A. Yes. In the well-known and often referenced, treatise <u>Principles of Public Utility Rates</u>, Professor James Bonbright states that there:

> is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[29]

Q. BEFORE WE CONTINUE, ARE KU's AND LG&E's DISTRIBUTION SYSTEMS COMPRISED OF VARIOUS SUB-SYSTEMS?

A. Yes. As is the case with virtually every electric utility, the Companies' overall distribution systems are comprised of primary voltage systems and secondary voltage systems. A primary system operates at higher voltage levels than a secondary system and generally consists of plant and equipment between the substations and transformers. A lower voltage secondary system can be thought of as operating downstream from a primary system and delivers electricity to small end-users at lower voltages.

Q. BRIEFLY DESCRIBE THE TYPES OF INVESTMENT (EQUIPMENT) UTILIZED IN THE COMPANIES' DISTRIBUTION SYSTEMS.

A. For accounting purposes, distribution plant is grouped into various accounts. These accounts include: Land and Land Rights (Account 360); Structures and Improvements (Account 361); Station Equipment (Account 362); Poles, Towers and Fixtures (Account 364); Overhead Conductors (Account 365); Underground Conduit (Account 366); Underground Conductors (Account 367); Line Transformers (Account 368); Meters (Account 370); Area Lighting (Account 371) and Street Lighting (Account 373).

Q. DID MR. SEELYE MAKE AN *A PRIORI* ASSUMPTION THAT DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

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[29] Bonbright, Principles of Public Utility Rates, Second Edition, page 491.

A. Yes.

Q. WHAT RELATIVE CUSTOMER/DEMAND PERCENTAGES DID MR. SEELYE USE IN THIS CASE?

A. The following are Mr. Seelye's customer/demand percentages used for each distribution plant account:

TABLE 18
Classification of Distribution Plant
Percent Customer

Account	KU	LG&E
Poles and Overhead Lines - Primary	63.99%	63.99%
Poles and Overhead Lines – Secondary	63.99%	63.99%
Underground Lines – Primary	74.88%	59.86%
Underground Lines – Secondary	74.88%	59.86%
Transformers (Secondary)	45.38%	35.79%

Q. HAVE YOU CONDUCTED ANALYSES TO DETERMINE IF A CLASSIFICATION OF DISTRIBUTION PLANT AS PARTIALLY CUSTOMER-RELATED IS APPROPRIATE FOR KU AND LG&E?

A. Yes, I have.

Q. PLEASE EXPLAIN.

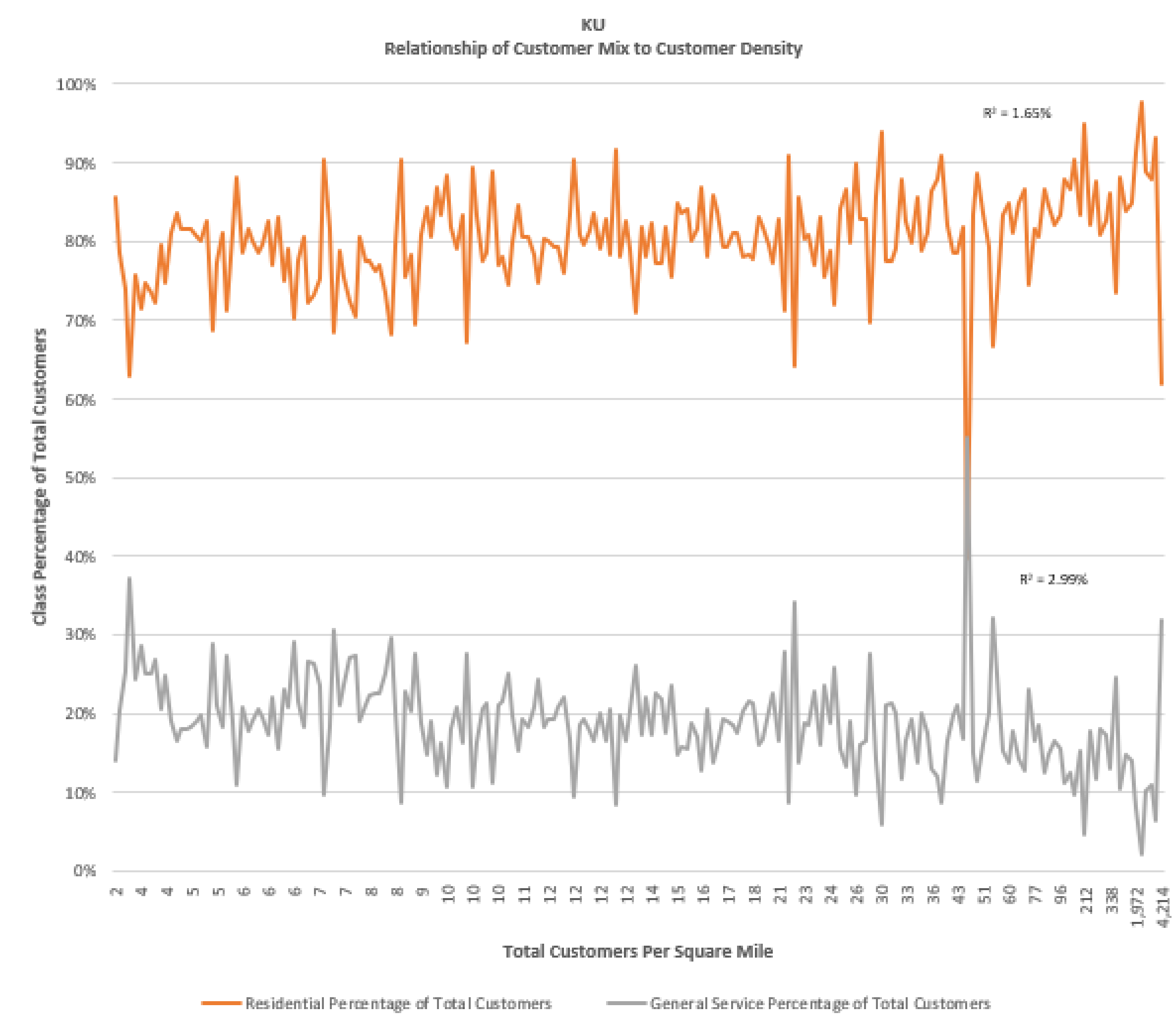
A. Mr. Seelye has made an *a priori* assumption that it is appropriate to allocate a portion of its distribution plant based on customer counts and a portion based on demand levels. As indicated earlier, the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than peak demand, is due to the possibility that the mix of customers varies significantly across the customer density levels within each service territory. In this regard, I evaluated this assumption by conducting an analysis of the distribution, or mix, of KU and LG&E customer classes across its service area.

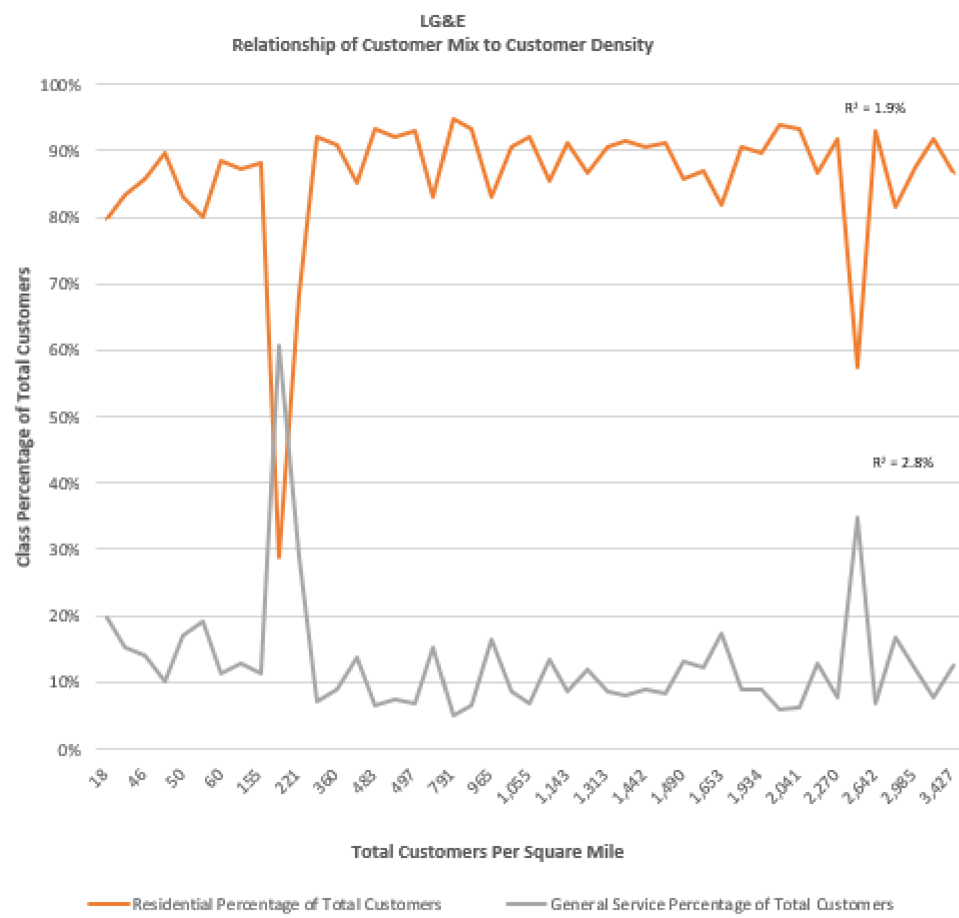
Through discovery, the Company provided a data base of the number of customers by rate schedule for each postal zip-code within each (KU and LG&E) service area.[30] I then evaluated the mix of customers by rate class for each postal zip-code within each service area. In order to evaluate whether any differences exist in the distribution of customers across various customer density areas, I calculated the number of total distribution customers (excluding lighting customers) per square mile for each non-Post Office Box zip-code to serve as a measure of density for relatively small geographic areas. I was then able to readily compare the mix of customers throughout each service area and delineate between sparsely populated and densely populated areas (in terms of number of customers). As a further refinement, I also evaluated the distribution of customers on a stratified basis. That is, for KU each customer group (Residential, General Service, Power Service, Time of Day, and All Electric Schools) I separated small geographical areas (zip codes) into four separate strata (lowest to highest customer densities). For LG&E, each customer group (Residential, General Service, Power Service, and Time of Day) I separated small geographical areas (zip codes) into three separate strata due to the much smaller number of total zip codes in the LG&E service area. I then examined each stratum (by customer group) to determine if any significant differences in customer mix occur within each stratum.

These analyses of the distribution of the various customer groups by density provided a basis to determine whether: (a) utilization alone (demand) is an appropriate and fair method to allocate distribution costs; or, (b) whether a weighting of customers and utilization (demand) is appropriate in order to reasonably reflect the imposition or causation of costs.

If there is any basis for a customer classification of distribution plant, this analysis should show a negative correlation between the residential customer mix (residential percentage of total customers) and density across each service area. In other words, the percentage of residential customers (by zip-code) should decline as customer density per square mile increases from the least dense areas to the most dense areas of the Companies' service territories. Similarly, if Mr. Seelye's assumption is correct, you should see a distinct positive correlation between non-residential customer mixes and customer densities by zip-code. The graph below shows the percentage of total customers by rate group (Y axis) compared to total customers per square mile (X axis):

[30] Per response to AG-KIUC 1-142 and AG-KIUC 1-143.


KU
Relationship of Customer Mix to Customer Density
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Class Percentage of Total Customers
R² = 1.65%
R² = 2.99%
Total Customers Per Square Mile
Residential Percentage of Total Customers
General Service Percentage of Total Customers



As can be seen in the graphs above, there is absolutely no correlation or trend between the distribution of customers (customer mix) and density levels for any of the three customer groups. Indeed, and as shown in these graphs, the correlation coefficients for all three customer groups are essentially zero.

As discussed earlier, I also analyzed this data on a stratified basis. A summary of the approach and data utilized for the stratification analysis is provided below:[31]

[31] The data and details of these analyses are provided in my filed workpapers.

TABLE 19
KU
Distribution of Customers By Density

			Percent of Total Distribution Customers[32]		
Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Percent Of Strata	Number	% of Class
Residential					
Strata 1	1.7 Min to 7.9 Max	52	77.0%	21,204	4.9%
Strata 2	8.0 Min to 13.5 Max	52	79.7%	40,712	9.4%
Strata 3	13.6 Min to 32.5 Max	51	79.0%	76,825	17.8%
Strata 4	> 32.5	51	85.4%	293,638	67.9%
Total		206		432,379	100.0%
General Service					
Strata 1	1.7 Min to 7.9 Max	52	22.0%	6,064	7.4%
Strata 2	8.0 Min to 13.5 Max	52	191%	9,770	12.0%
Strata 3	13.6 Min to 32.5 Max	51	19.8%	19,250	23.6%
Strata 4	> 32.5	51	13.5%	46,507	57.0%
Total		206		81,591	100.0%
Power Service					
Strata 1	1.7 Min to 7.9 Max	52	0.7%	183	4.1%
Strata 2	8.0 Min to 13.5 Max	52	0.5%	424	9.5%
Strata 3	13.6 Min to 32.5 Max	51	0.5%	844	18.9%
Strata 4	> 32.5	51	0.8%	3,005	67.4%
Total		206		4,456	100.0%
Time of Day					
Strata 1	1.7 Min to 7.9 Max	52	0.1%	30	3.0%
Strata 2	8.0 Min to 13.5 Max	52	0.2%	79	8.0%
Strata 3	13.6 Min to 32.5 Max	51	0.2%	198	20.0%
Strata 4	> 32.5	51	0.2%	683	69.0%
Total		206		990	100.0%
All Electric Schools					
Strata 1	1.7 Min to 7.9 Max	52	0.2%	41	9.9%
Strata 2	8.0 Min to 13.5 Max	52	0.2%	75	18.0%
Strata 3	13.6 Min to 32.5 Max	51	0.1%	114	27.4%
Strata 4	> 32.5	51	0.1%	186	44.7%
Total		206		416	100.0%

[32] Excludes transmission, lighting and EV classes.

TABLE 20
LG&E
Distribution of Customers By Density

Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Percent Of Strata	Percent of Total Distribution Customers[33] Number	% of Class
Residential					
Strata 1	18 Min to 483 Max	15	87.4%	67,916	18.2%
Strata 2	484 Min to 1,442 Max	15	90.6%	175,389	47.0%
Strata 3	> 1,442	15	87.7%	130,180	34.9%
Total		45		373,485	100.0%
General Service					
Strata 1	18 Min to 483 Max	15	11.5%	8,903	20.9%
Strata 2	484 Min to 1,442 Max	15	8.7%	16,871	39.5%
Strata 3	> 1,442	15	11.4%	16,887	39.6%
Total		45		42,661	100.0%
Power Service					
Strata 1	18 Min to 483 Max	15	0.6%	483	17.6%
Strata 2	484 Min to 1,442 Max	15	8.8%	1,158	42.1%
Strata 3	> 1,442	15	0.8%	1,110	40.3%
Total		45		2,751	100.0%
Time of Day					
Strata 1	18 Min to 483 Max	15	0.1%	101	16.8%
Strata 2	484 Min to 1,442 Max	15	0.1%	256	42.6%
Strata 3	> 1,442	15	0.2%	244	40.6%
Total		45		601	100.0%

Q. WHAT ARE YOUR FINDINGS AS A RESULT OF THIS ANALYSIS?

A. KU's customers are dispersed in a reasonably proportional manner throughout its service area. In fact, the distribution of residential customers is somewhat greater in the more densely populated zip codes than the less densely populated zip codes, which is contrary to the hypothesis and is opposite of what would be expected if one were to accept the notion that distribution investment should be classified as partially customer-related. As important is the fact that in the less dense areas of KU's service territory (which requires more miles of distribution lines and number of poles to serve fewer customers), the Company actually serves a larger percentage of General Service customers than in the more densely populated areas within KU's service territory.

[33] Excludes transmission, lighting and EV classes.

Similarly, LG&E's customers are also dispersed in a reasonable proportional manner throughout its service area.

As a result of these analyses, it cannot be said that the less populated portions of the Companies' service areas (which require significant investment to serve few customers) are disproportionately required to serve any one class of customers. As such, with respect to the Companies' primary voltage distribution systems, plant and expenses should be assigned to classes based only on peak demand and any consideration of customer counts is improper for the allocation of distribution plant. Therefore, my studies indicate that the Companies' primary voltage distribution systems costs should be classified as 100% demand-related.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE CLASSIFICATION OF THE COMPANIES' SECONDARY VOLTAGE DISTRIBUTION SYSTEMS?

A. In conducting the analysis discussed above, I recognize that the Companies' primary voltage distribution systems serve more customers and provide more power and energy than does their secondary voltage systems. In other words, the secondary voltage systems can be thought of as serving customers downstream from the primary voltage system. As such, the secondary voltage systems serve smaller individual geographical areas such as individual neighborhoods, etc. The smallest geographical area in which I have data available to evaluate customer densities and customers mixes is on a zip code basis. Because an individual neighborhood (or secondary voltage circuit) may encompass a relatively small geographical area, I cannot reasonably opine as to whether it is inappropriate to classify a portion of the Companies' secondary system based partially on customers and based partially on demand. Therefore, I have accepted Mr. Seelye's classification of secondary voltage distribution plant as partially customer-related and partially demand-related.

Q. DOES THE NARUC ELECTRIC COST ALLOCATION MANUAL INDICATE IF AN *A PRIORI* ASSUMPTION IS APPROPRIATE REGARDING WHETHER DISTRIBUTION COSTS MUST BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. No. In fact, the NARUC Manual (published in 1992) states the following:

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.
>
> Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. (page 89)

Q. HAS NARUC PROVIDED MORE RECENT GUIDANCE CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT THAN WHAT WAS PUBLISHED IN THE 1992 NARUC ELECTRIC COST ALLOCATION MANUAL?

A. Yes. The 1992 NARUC Manual was written in an era when all retail utility services were bundled (generation, transmission and distribution). Subsequent to the unbundling of retail rates in the mid to late 1990's by several state jurisdictions, NARUC commissioned a study to examine the costing and pricing of electric distribution service in further detail. In December 2000, NARUC published a report entitled: <u>Charging For Distribution Services: Issues in Rate Design</u>. As part of the Executive Summary this report states:

> The usefulness of cost analyses of the distribution system in designing rate structures and setting rate levels depends in large measure upon the manner in which the studies are undertaken. Cost studies (both marginal and embedded) are intended, among other things, to determine the nature and causes of costs, so that they can then be reformulated into rates that cost-causers can pay. Such studies must of necessity rely on a host of simplifying assumptions in order to produce workable results; this is especially true of embedded cost studies. Moreover, it is often the case that many of the costs (*e.g.,* administrative and general) that distribution rates recover are not caused by provision of distribution service, but are assigned to it arbitrarily. Too great dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design. (page 67)

With specific regard to classification and allocation of certain distribution plant (poles, wires and transformers), Chapter IV of this report is devoted to the costing of distribution services. With respect to embedded cost analyses this updated NARUC report states:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.
>
> Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related. However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).
>
> Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in

> competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access. (pages 29 & 30)

In summary, when all of the facts and guidelines are known, it is clear to me that: (a) data and analysis specific to each utility is more appropriate and preferred over an *a priori* assumption that distribution plant must be partially customer-related; and, (b) many (if not most) state regulatory commissions endorse a method in which all distribution plant from substations through line transformers is classified and allocated based solely on demand. A copy of the entire Chapter (IV) from the 2000 NARUC Publication discussing costing studies is provided in my Schedule GAW-24.

Q. WHY IS THE CLASSIFICATION OF DISTRIBUTION PLANT IMPORTANT IN CCOSS ANALYSES?

A. The classification of distribution plant may be the single most important factor affecting class rates of return. To illustrate the importance of this issue, consider the Residential class: whereas this class may account for only 40% to 50% of peak demand, it is responsible for a much higher percentage of the number of customers. Therefore, given the level of investment associated with distribution plant, wide variations in class rates of return can result from different customer/demand classifications.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT IN THIS CASE?

A. Based on my customer density/mix analyses of KU's and LG&E's distribution systems, it is apparent that the primary voltage distribution systems costs should be classified as 100% demand-related. With regard to the secondary voltage distribution systems, I have accepted Mr. Seelye's customer/demand classifications.

Q. PLEASE PROVIDE TABLES SHOWING CLASS RORs UNDER YOUR PROBABILITY OF DISPATCH METHODS WHEREIN DISTRIBUTION PRIMARY VOLTAGE COSTS ARE ALLOCATED 100% ON PEAK DEMAND.

A. The following tables provide the requested summary RORs by class. In this regard, and due to the voluminous nature of these various studies, the details are provided in my filed workpapers.

TABLE 21
Kentucky Utilities
Probability of Dispatch Results
RORs at Current Rates
(Utilizing 100% Primary Demand)

	Historic		Forecasted		
Rate Schedule	Pro- Rata Allocation	Market-Based Allocation	Pro- Rata Allocation	Market-Based Allocation	Average
Rate RS	4.45%	4.19%	4.62%	4.34%	4.40%
Rate GS	12.43%	12.33%	12.73%	12.63%	12.53%
Rate AES	3.92%	3.83%	3.95%	3.91%	3.90%
Rate PS - Secondary	8.48%	8.54%	9.01%	9.10%	8.78%
Rate PS - Primary	5.41%	5.59%	15.97%	16.18%	10.79%
Rate TOD - Secondary	3.14%	3.31%	2.48%	2.63%	2.89%
Rate TOD - Primary	0.88%	1.15%	0.39%	0.67%	0.77%
Rate RTS	0.15%	0.42%	0.47%	0.77%	0.45%
Rate FLS	1.04%	1.48%	-0.20%	0.17%	0.62%
Rate LS & RLS	10.88%	11.39%	10.69%	11.11%	11.02%
Rate LE	4.85%	6.27%	1.23%	2.25%	3.65%
Rate TE	12.60%	13.26%	10.11%	10.66%	11.66%
Rate OSL	19.97%	19.99%	21.00%	21.06%	20.50%
Rate EV	-27.00%	-27.00%	-27.00%	-27.00%	-27.00%
Rate SSP	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Rate BS	4.80%	4.80%	4.80%	4.80%	4.80%
Total KU	4.81%	4.81%	4.81%	4.81%	4.81%

TABLE 22
LG&E
Probability of Dispatch Results
RORs at Current Rates
(Utilizing 100% Primary Demand)

	Historic		Forecasted		
Rate Schedule	Pro- Rata Allocation	Market-Based Allocation	Pro- Rata Allocation	Market-Based Allocation	Average
Rate RS	3.76%	3.50%	4.02%	3.77%	3.76%
Rate GS	10.83%	10.76%	11.32%	11.27%	11.05%
Rate PS - Primary	11.47%	11.78%	8.91%	9.12%	10.32%
Rate PS - Secondary	6.16%	6.19%	7.06%	7.11%	6.63%
Rate TOD - Primary	0.60%	0.94%	0.50%	0.83%	0.72%
Rate TOD - Secondary	2.89%	3.07%	1.66%	1.78%	2.35%
Rate RTS	1.37%	1.84%	-0.06%	0.37%	0.88%
Special Contract	-1.60%	-1.21%	-1.81%	-1.53%	-1.54%
Rate RLS & LS	7.27%	7.70%	7.03%	7.34%	7.33%
Rate LE	-1.18%	-0.05%	-1.86%	-1.12%	-1.05%
Rate TE	8.15%	8.80%	8.07%	8.61%	8.40%
Rate OSL	43.65%	43.01%	61.03%	61.00%	52.17%
Rate EV	-27.07%	-27.07%	-27.07%	-27.07%	-27.07%
Rate SSP	3.60%	3.60%	3.60%	3.60%	3.60%
Rate BS	-4.38%	-4.38%	-4.38%	-4.38%	-4.38%
Total LG&E	4.34%	4.34%	4.34%	4.34%	4.34%

6. <u>OAG Recommended CCOSS</u>

Q. WHAT ARE THE CCOSS RESULTS UTILIZING THE GENERATION ALLOCATION METHODS YOU DISCUSSED EARLIER AND ALSO CLASSIFICATION OF PRIMARY VOLTAGE DISTRIBUTION PLANT AS 100% DEMAND-RELATED?

A. The following provides a summary of my CCOSS results at current rates under each allocation method wherein primary voltage distribution costs are classified as 100% demand-related:

TABLE 23
KU
100% Primary Voltage Demand Distribution Plant
ROR At Current Rates

Class	Probability of Dispatch (Average)	BIP	Average (POD & BIP)
Rate RS	4.40%	4.46%	4.43%
Rate GS	12.53%	12.52%	12.53%
Rate AES	3.90%	3.76%	3.83%
Rate PS – Secondary	8.78%	8.85%	8.82%
Rate PS – Primary	10.79%	16.36%	13.57%
Rate TOD – Secondary	2.89%	2.61%	2.75%
Rate TOD – Primary	0.77%	0.54%	0.66%
Rate RTS	0.45%	0.68%	0.57%
Rate FLS	0.62%	0.42%	0.52%
Rate LS & RLS	11.02%	11.06%	11.04%
Rate LE	3.65%	1.99%	2.82%
Rate TE	11.66%	10.60%	11.13%
Rate OSL	20.50%	21.40%	20.95%
Rate EV	-27.00%	-27.00%	-27.00%
Rate SSP	-1.31%	-1.31%	-1.31%
Rate BS	4.80%	4.80%	4.80%
Total KU	4.81%	4.81%	4.81%

TABLE 24
LG&E
100% Primary Voltage Demand Distribution Plant
ROR At Current Rates

Class	Probability of Dispatch (Average)	BIP	Average (POD & BIP)
Rate RS	3.76%	3.74%	3.75%
Rate GS	11.05%	11.07%	11.06%
Rate PS – Primary	10.32%	9.20%	9.76%
Rate PS – Secondary	6.63%	7.09%	6.86%
Rate TOD – Primary	0.72%	0.77%	0.74%
Rate TOD – Secondary	2.35%	1.91%	2.13%
Rate RTS	0.88%	0.51%	0.69%
Special Contract	-1.54%	-1.13%	-1.33%
Rate RLS & LS	7.33%	7.53%	7.43%
Rate LE	-1.05%	-0.75%	-0.90%
Rate TE	8.40%	9.06%	8.73%
Rate OSL	52.17%	60.95%	56.56%
Rate EV	-27.07%	-27.07%	-27.07%
Rate SSP	3.60%	3.60%	3.60%
Rate BS	-4.38%	-4.38%	-4.38%
Total LG&E	4.34%	4.34%	4.34%

Q. WHAT ARE YOUR CONCLUSIONS REGARDING ELECTRIC CLASS COST ALLOCATIONS IN THIS CASE?

A. As can be seen in the tables above, while absolute class RORs vary across allocation methodologies, there are relative consistencies across several classes.

With respect to KU, the TOD (Secondary and Primary), Retail Transmission Service (Rate RTS), Fluctuating Load Service (Rate FLS) and Lighting Energy (Rate LE) classes are considerably lower than the system average ROR regardless of allocation approach, while the General Service (Rate GS), Power Service (Secondary and Primary), Lighting (Rate LS & RLS), Traffic (Rate TE), and Outdoor Sports Lighting (Rate OSL) RORs tend to be significantly greater than the system average ROR.

With regard to LG&E, the TOD (Secondary and Primary), Retail Transmission Service (Rate RTS), Special Contract, and Lighting Energy (Rate LE) classes are considerably lower than the system average ROR regardless of allocation approach, while the General Service (Rate GS), Power Service (Secondary and Primary) classes, Lighting (Rate LS & RLS), Traffic (Rate TE), and Outdoor Sports Lighting (Rate OSL) RORs tend to be significantly greater than the system average ROR.

These profitability patterns across methodologies can then be used as a tool in evaluating reasonable individual class increases.

B. Electric Class Revenue Distribution

Q. WHAT ARE THE GENERAL CRITERIA THAT SHOULD BE CONSIDERED IN ESTABLISHING CLASS REVENUE RESPONSIBILITY FOR ELECTRIC UTILITY RATES?

A. There are several criteria that should be considered in evaluating class or rate revenue responsibility. First, class cost allocation results should be considered, but as discussed in detail earlier in my testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure;

affordability of electricity across various classes as well as a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria to be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. In this regard, there is no universal mathematical methodology that can be applied across all utilities or across all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases. These include: some movement towards allocated cost of service; and, maximum/minimum percentage changes across individual rate classes.

1. <u>KU Class Revenue Distribution</u>

Q. PLEASE PROVIDE A SUMMARY OF MR. SEELYE'S PROPOSED CLASS REVENUE INCREASE FOR KU.

A. The following table provide a summary of current and Mr. Seelye's proposed revenue by rate class for KU:

TABLE 25
KU's Proposed Class Revenue Increases
($000)

Class	Revenue At Present Rates	Proposed Increase	% Increase
Rate RS	$638,824	$68,196	10.68%
Rate GS	$250,362	$26,735	10.68%
Rate AES	$13,615	$1,454	10.68%
Rate PS – Secondary	$173,817	$18,553	10.67%
Rate PS – Primary	$9,736	$1,040	10.68%
Rate TOD – Secondary	$135,932	$14,531	10.69%
Rate TOD – Primary	$252,230	$26,942	10.68%
Rate RTS	$82,241	$8,787	10.68%
Rate FLS	$32,878	$3,514	10.69%
Rate LS & RLS	$33,374	$0	0.00%
Rate LE	$336	$0	0.00%
Rate TE	$288	$0	0.00%
Rate OSL	$96	-$5	-4.97%
Rate EV	$2	$0	0.00%
Rate SSP	$163	$0	0.00%
Rate BS	$38	$0	0.00%
Curtailable Service Rider	-$18,634	$0	0.00%
Total Rate Revenue	$1,605,296	$169,747	10.57%
Other Revenue	$37,126	$373	1.16%
Imputed Solar & EV	$0	$354	--
Total KU	$1,642,422	$170,474	10.38%

Q. IS MR. SEELYE'S PROPOSED CLASS REVENUE INCREASES REASONABLE FOR KU?

A. Not entirely. That is, Mr. Seelye appears to have given little, to no, consideration of CCOSS results. For example, Mr. Seelye proposes no increase in revenue responsibility to the lighting classes (LS & RLS, LE, and TE) presumably because these classes are producing relatively high RORs at current rates; i.e., significantly above the system average. However, Mr. Seelye proposes equal percentage increases of 10.68% for Rates GS, PS Secondary, and PS Primary even though these classes also exhibit significantly high RORs at current rates.

Furthermore, Mr. Seelye's high rates of return for the lighting classes (RLS & LS, LE and TE) are a result of his LOLP allocation method in which generation costs are allocated almost entirely on peak Summer afternoon hours when lighting is offline. As a result, the lighting classes are assigned exceptionally low generation-related cost responsibility even though these rate classes rely on the Companies' generation facilities every single night (as well as throughout the day for Rate TE).

A comparison of Mr. Seelye's calculated class RORs and his recommended class percentage increases can be seen in the table below:

TABLE 26
KU's Proposed Class Revenue Increases
($000)

Class	Seelye ROR @ Current Rates	OAG Average ROR	% Increase
Rate RS	2.67%	4.43%	10.68%
Rate GS	11.05%	12.53%	10.68%
Rate AES	5.89%	3.83%	10.68%
Rate PS – Secondary	9.95%	8.82%	10.67%
Rate PS – Primary	17.91%	13.57%	10.68%
Rate TOD – Secondary	3.95%	2.75%	10.69%
Rate TOD – Primary	3.20%	0.66%	10.68%
Rate RTS	3.53%	0.57%	10.68%
Rate FLS	2.75%	0.52%	10.69%
Rate LS & RLS	12.32%	11.04%	0.00%
Rate LE	28.05%	2.82%	0.00%
Rate TE	12.39%	11.13%	0.00%
Rate OSL	30.32%	20.95%	-4.97%
Rate EV	-27.00%	-27.00%	0.00%
Rate SSP	-1.31%	-1.31%	0.00%
Rate BS	4.80%	4.80%	0.00%
Curtailable Service Rider	--	--	0.00%
Total Rate Revenue			10.57%
Other Revenue			1.16%
Imputed Solar & EV			--
Total KU			10.38%

Q. DO YOU RECOMMEND ALTERNATIVE KU CLASS REVENUE INCREASES TO THOSE PROPOSED BY MR. SEELYE?

A. Yes. I offer two options for the Commission's consideration. My first option is very similar to Mr. Seeyle's proposal except that the lighting classes (Rates LS & RLS, LE and TE) also share equally in the overall authorized increase.[34]

My second option considers gradualism as well as recognizes movement toward cost of service. In developing my second option, I have relied primarily on my recommended CCOSS results shown in my Table 26. As indicated in my Table 26, Rate TOD (Secondary and Primary), Rate RTS, Rate FLS and Rate LE all are producing significantly low RORs while Rates GS, PS (Secondary and Primary), LS & RLS, and TE are producing significantly high RORs. Therefore, for the above-referenced under contributing classes, I recommend that these classes be increased at 125% of the system average increase while those referenced over contributing classes be increased at 75% of the system average increase.

My recommended KU class revenue increases under Option 1 and Option 2 are provided in the table below:

[34] I have no objection to the slight reduction to Rate OSL.

TABLE 27
OAG Recommended Class Revenue Increases
($000)

Rate Schedule	Revenues @ Current Rates	Dollar Increase Option 1	Dollar Increase Option 2	Percent Increase Option 1	Percent Increase Option 2
Rate RS	$638,824	$66,790	$65,867	10.46%	10.31%
Rate GS	$250,362	$26,176	$19,632	10.46%	7.84%
Rate AES	$13,615	$1,423	$1,404	10.46%	10.31%
Rate PS – Secondary	$173,817	$18,173	$13,630	10.46%	7.84%
Rate PS – Primary	$9,736	$1,018	$763	10.46%	7.84%
Rate TOD – Secondary	$135,932	$14,212	$17,765	10.46%	13.07%
Rate TOD – Primary	$252,230	$26,371	$32,964	10.46%	13.07%
Rate RTS	$82,241	$8,598	$10,748	10.46%	13.07%
Rate FLS	$32,878	$3,437	$4,297	10.46%	13.07%
Rate LS & RLS	$33,374	$3,489	$2,617	10.46%	7.84%
Rate LE	$336	$35	$44	10.46%	13.07%
Rate TE	$288	$30	$23	10.46%	7.84%
Rate OSL	$96	-$5	-$5	-4.97%	-4.97%
Rate EV	$2	$0	$0	0.00%	0.00%
Rate SSP	$163	$0	$0	0.00%	0.00%
Rate BS	$38	$0	$0	0.00%	0.00%
Curtailable Service Rider	-$18,634	$0	$0	0.00%	0.00%
Total Rate Revenue	$1,605,296	$169,747	$169,747	10.57%	10.57%
Other Revenue	$37,126	$373	$373	1.01%	1.01%
Imputed Solar & EV	$0	$354	$354	--	--
Total KU	$1,642,422	$170,475	$170,475	10.38%	10.38%

2. LG&E Electric Class Revenue Distribution

Q. PLEASE PROVIDE A SUMMARY OF MR. SEELYE'S PROPOSED CLASS REVENUE INCREASE FOR LG&E.

A. The following table provides a summary of current and Mr. Seelye's proposed revenue by rate class for LG&E:

TABLE 28
LG&E's Proposed Class Revenue Increases
($000)

Class	Revenue At Present Rates	Proposed Increase	% Increase
Rate RS	$450,298	$53,156	11.80%
Rate GS	$161,806	$19,106	11.81%
Rate PS – Primary	$10,376	$1,226	11.81%
Rate PS – Secondary	$151,745	$17,917	11.81%
Rate TOD – Primary	$138,483	$16,362	11.81%
Rate TOD – Secondary	$103,388	$12,217	11.82%
Rate RTS	$65,181	$7,690	11.80%
Special Contract	$3,688	$435	11.80%
Rate RLS & LS	$24,177	$2,877	11.90%
Rate LE	$257	$0	0.00%
Rate TE	$333	$0	0.00%
Rate OSL	$16	-$2	-10.01%
Rate EV	$2	$0	0.00%
Rate SSP	$237	$0	0.00%
Rate BS	$10	$0	0.00%
Curtailable Service Rider	-$2,468	$0	0.00%
Total Rate Revenue	$1,107,530	$130,983	11.83%
Other Revenue	$21,265	$90	0.42%
Imputed Solar & EV	$0	$176	--
Total LG&E	$1,128,794	$131,249	11.63%

Q. IS MR. SEELYE'S PROPOSED CLASS REVENUE INCREASES REASONABLE FOR LG&E?

A. Not entirely. That is, Mr. Seelye appears to have given little, to no, consideration of CCOSS results. For example, Mr. Seelye proposes no increase in revenue responsibility to Rate TE presumably because this class is producing a relatively high ROR at current rates; i.e., significantly above the system average. However, Mr. Seelye proposes an equal percentage increase of 11.81% for Rate PS Primary even though this class also exhibits a significantly high ROR at current rates.

Furthermore, Mr. Seelye's high rates of return for the lighting classes (RLS & LS, LE and TE) are a result of his LOLP allocation method in which generation costs are allocated almost entirely on peak Summer afternoon hours when lighting is offline. As a result, the lighting classes are assigned exceptionally low generation-related cost responsibility even though these rate classes rely on the Companies' generation facilities every single night (as well as throughout the day for Rate TE).

A comparison of Mr. Seelye's calculated class RORs and his recommended class percentage increases can be seen in the table below:

TABLE 29
LG&E's Proposed Class Revenue Increases
($000)

Class	Seelye ROR @ Current Rates	OAG Average ROR	% Increase
Rate RS	0.60%	3.75%	11.80%
Rate GS	10.96%	11.06%	11.81%
Rate PS – Primary	14.43%	9.76%	11.81%
Rate PS – Secondary	10.30%	6.86%	11.81%
Rate TOD – Primary	6.45%	0.74%	11.81%
Rate TOD – Secondary	5.33%	2.13%	11.82%
Rate RTS	7.23%	0.69%	11.80%
Special Contract	5.52%	-1.33%	11.80%
Rate RLS & LS	9.74%	7.43%	11.90%
Rate LE	31.88%	-0.90%	0.00%
Rate TE	15.01%	8.73%	0.00%
Rate OSL	89.10%	56.56%	-10.01%
Rate EV	-27.07%	-27.07%	0.00%
Rate SSP	3.60%	3.60%	0.00%
Rate BS	-4.38%	-4.38%	0.00%
Curtailable Service Rider	--	--	0.00%
Total Rate Revenue	4.34%	4.34%	11.83%
Other Revenue			0.42%
Imputed Solar & EV			--
Total LG&E			11.63%

Q. DO YOU RECOMMEND ALTERNATIVE LG&E CLASS REVENUE INCREASES TO THOSE PROPOSED BY MR. SEELYE?

A. Yes. I also offer two options for the Commission's consideration. My first option is very similar to Mr. Seeyle's proposal except that the lighting classes (Rates LE and TE) also share equally in the overall authorized increase.[35]

My second option considers gradualism as well as recognizes movement toward cost of service. In developing my second option, I have relied primarily on my recommended CCOSS results shown in my Table 29. As indicated in my Table 29, Rate TOD (Secondary and Primary), Rate RTS, Special Contract and Rate LE all are producing significantly low RORs while Rates GS, PS Primary, RLS & LS, and TE are producing significantly high RORs. Therefore, for the above-referenced under contributing classes, I recommend that these classes be increased at 125% of the system average increase while those referenced over contributing classes be increased at 75% of the system average increase.

My recommended LG&E class revenue increases under Option 1 and Option 2 are provided in the table below:

[35] I have no objection to the reduction to Rate OSL.

TABLE 30
OAG Recommended Class Revenue Increases
($000)

Rate Schedule	Revenues @ Current Rates	Dollar Increase Option 1	Dollar Increase Option 2	Percent Increase Option 1	Percent Increase Option 2
Rate RS	$450,298	$53,150	$50,627	11.80%	11.24%
Rate GS	$161,806	$19,098	$14,324	11.80%	8.85%
Rate PS – Primary	$10,376	$1,225	$919	11.80%	8.85%
Rate PS – Secondary	$151,745	$17,911	$17,061	11.80%	11.24%
Rate TOD – Primary	$138,483	$16,346	$20,432	11.80%	14.75%
Rate TOD – Secondary	$103,388	$12,203	$15,254	11.80%	14.75%
Rate RTS	$65,181	$7,694	$9,617	11.80%	14.75%
Special Contract	$3,688	$435	$544	11.80%	14.75%
Rate RLS & LS	$24,177	$2,854	$2,140	11.80%	8.85%
Rate LE	$257	$30	$38	11.80%	14.75%
Rate TE	$333	$39	$29	11.80%	8.85%
Rate OSL	$16	-$2	-$2	-10.00%	-10.00%
Rate EV	$2	$0	$0	0.00%	0.00%
Rate SSP	$237	$0	$0	0.00%	0.00%
Rate BS	$10	$0	$0	0.00%	0.00%
Curtailable Service Rider	-$2,468	$0	$0	0.00%	0.00%
Total Rate Revenue	$1,107,530	$130,983	$130,983	11.83%	11.83%
Other Revenue	$21,265	$90	$90	0.42%	0.42%
Imputed Solar & EV	$0	$176	$176	--	--
Total LG&E	$1,128,794	$131,249	$131,249	11.63%	11.63%

C. Electric Residential Rate Design

1. Residential Customer Charges

Q. DO THE COMPANIES PROPOSE TO INCREASE THEIR FIXED RESIDENTIAL ELECTRIC CUSTOMER CHARGES?

A. Yes. Witness Seelye proposes the following increases to electric residential customer charges:

TABLE 31
Electric Residential Customer Charges

	Current Rate		Proposed Rate		Monthly	Percent
	Daily	Monthly	Daily	Monthly	Increase	Increase
KU	$0.53	$16.12	$0.61	$18.55	$2.43	15.1%
LG&E	$0.45	$13.69	$0.52	$15.82	$2.13	15.6%

Q. HOW DOES MR. SEELYE SUPPORT THESE INCREASES IN FIXED RESIDENTIAL CUSTOMER CHARGES?

A. Mr. Seelye offers three rationale for high customer charges. First, Mr. Seelye is of the opinion that because the majority of the Companies' total costs of providing service are "fixed" in nature, a large portion of revenue should be collected from fixed charges. Second, Mr. Seelye claims that higher fixed charges will help eliminate intra-class subsidies within the residential class. Third, Mr. Seelye claims that his "methodology for classifying costs as customer-related also corresponds to one of the standard methodologies set forth in the *Electric Utility Cost Allocation Manual* published by the National Association of Utility Regulatory Commissioners (NARUC)."[36]

Q. IS MR. SEELYE'S ASSERTION THAT FIXED COSTS SHOULD BE COLLECTED FROM FIXED CHARGES IN ACCORDANCE WITH SOUND ECONOMIC PRINCIPLES OR ACCEPTED PRICING PRACTICES?

A. No. Mr. Seelye has a profound misunderstanding of sound economic principles, and their assertions are contrary to accepted pricing practices. First, I will discuss the theoretical aspects of sound economic pricing principles and then I will discuss accepted pricing practices in our economy.

The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for

[36] Seelye Direct Testimony at 16-17.

competition to the greatest extent practical.[37] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[38] It is well known that all costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

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[37] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

[38] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS KU AND LG&E.

A. Due to the Companies' investments in system infrastructure, there is no debate that many of their short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity and natural gas usage, i.e., the level of kWh or CCF consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. ARE THE ELECTRIC AND NATURAL GAS UTILITY INDUSTRIES UNIQUE IN THEIR COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing, agricultural, and transportation industries are comprised of cost structures predominated with "fixed" costs. Obvious examples of these industries include: automobile and truck manufacturing; petroleum production; farming; airline; rail transportation; and shipping transportation. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated.

Accordingly, Mr. Seelye's position that fixed costs should be recovered through fixed monthly charges is misplaced. Pricing should reflect the Companies' long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Companies' products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. CAN YOU PROVIDE AN ANALOGY OF THE COMPETITIVE PRICING STRUCTURE FOR AN INDUSTRY SIMILAR TO KU AND LG&E?

A. Yes. Products pipelines which transport petroleum products, anhydrous ammonia, etc. are generally not regulated and are very competitive in nature.[39] These pipeline's pricing structures are based on a per barrel, or per barrel-mile basis, wherein there are no "fixed" customer charges. Indeed, simply because of competition, the only way in which KU and LG&E can substantiate such fixed charges is due to its monopoly power.

Q. DO SOME COMPETITIVE INDUSTRIES HAVE PRICING STRUCTURES THAT ARE LARGELY COMPRISED OF FIXED MONTHLY CHARGES?

A. Yes, there are a few – namely, the telecommunications industries (telephone, internet and cable). However, there are two important points to consider in evaluating the pricing structures of these industries. First and foremost, the incremental cost of an additional minute or kilobyte of usage is miniscule in that it is not cost effective to meter such usage. Second, is the fact that these pricing structures are not truly "fixed" in nature. For example, in the cable industry, a customer will subscribe to various packages such that the more services that are provided, the more the customer will pay. Similarly, for internet and cell phone services, there tends to be blocked usage packages available

[39] The FERC does regulate products pipelines for those markets in which there is no competition. However, for markets in which competition exists, there is no price regulation.

with prices higher for larger amounts of data or minutes of use. Finally, from a public policy perspective, these industries differ from electric and natural gas utilities in that the telecommunications industries do not produce or provide energy, which are scarce natural resources.

Q. ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. Yes. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[40] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[41] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[42]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the

[40] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.
[41] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.
[42] *Id.* p. 8 (alteration in original).

> use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[43]

Recently, some public utilities have begun to advocate SFV residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. ARE CONSERVATION AND EFFICIENCY GAINS A NEW RISK TO PUBLIC UTILITIES?

A. No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average residential electric and natural gas usage per appliance has been declining, utilities have remained financially healthy and have continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and

[43] *Id.* pp. 128-129.

efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status (and regulator approval). In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. PLEASE RESPOND TO MR. SEELYE'S CONCERN THAT FIXED COSTS TYPICALLY WILL NOT CHANGE IF A CUSTOMER USES MORE ENERGY OR IF A CUSTOMER USES LESS ENERGY.

A. First, it should be remembered that the concept of "fixed" costs are an accounting concept. These so-called fixed costs are more properly referred to as sunk costs in that these are costs that are required to provide service to customers for the purchase and use of energy. As discussed earlier, there are numerous industries with a high degree of sunk costs required to provide their products and services to customers. Second, Mr. Seelye's concern appears to also relate to the Companies' desire for revenue stability and any risk associated with not collecting revenues due to lower than requested fixed customer charges. In order to evaluate any concern over revenue stability and/or risk associated with not collecting revenues due to reasonably low fixed customer charges, the following tables provide the average residential usage per customer (on a weather normalized basis) for each of the last six years:[44]

TABLE 32
KU
Average Residential (RS) Electric Use per Customer
(Weather Normalized)

Year	MWH	Avg. Cust.	Avg. Use KWH	Variance from Avg.
2015	6,034,195	422,871	14,270	2.41%
2016	5,820,433	425,366	13,683	-1.80%
2017	5,855,239	428,637	13,660	-1.97%
2018	6,048,994	430,710	14,044	0.79%
2019	5,966,249	433,776	13,754	-1.29%
2020	6,216,223	437,947	14,194	1.87%
	Average		13,934	

TABLE 33
LG&E Electric
Average Residential (RS) Electric Use per Customer
(Weather Normalized)

Year	MWH	Avg. Cust.	Avg. Use KWH	Variance from Avg.
2015	4,099,225	357,122	11,479	1.72%
2016	4,052,621	360,099	11,254	-0.27%
2017	4,117,743	363,331	11,333	0.43%
2018	4,097,359	365,005	11,225	-0.53%
2019	4,105,776	368,800	11,133	-1.35%
2020	4,221,189	374,077	11,284	-0.01%
	Average		11,285	

Considering that the Companies have rate cases every two to three years and that the rate application in this case is based on a weather normalized forecasted test year, the above tables clearly demonstrate there is little chance that the Companies will not collect its

[44] For the years 2015 through 2017, per the Companies' response to KIUC 1-8 in Case nos. 2018-00294 and 2018-00295. For the years 2018 through 2020, per the Companies' response to AG-KIUC 1-180 in this case.

revenues from residential customers absent higher fixed customer charges.

Q. PLEASE RESPOND TO MR. SEELYE'S ASSERTION THAT HIGHER FIXED CUSTOMER CHARGES HELP REDUCE INTRA-CLASS SUBSIDIES.

A. Although I have already explained why the notion that fixed costs should be recovered from fixed charges does not comport with accepted economic theory and practice, the genesis of Mr. Seelye's rationale relating to intra-class subsidies rests on the premise that the revenue derived from small volume customers does not sufficiently recover the total costs to provide service, such that the revenue generated from large volume customers subsidize the small volume customers. Mr. Seelye's rationale and opinion is incorrect and fails to consider two important aspects of cost causation and ratemaking principles and practices.

First, one must compare the "cost causation" of "small volume and large volume" customers within a particular rate class particularly as it relates to residential customers. Based on the seasonal nature of the demand for electricity, residential customers use much more electricity in the Winter and Summer months than during the Spring and Fall months due to the use of electricity for heating and air conditioning. Some residential customers do not use electricity for space heating purposes and may not have air conditioning (or use in a limited fashion). As such, these annual small volume customers use electricity at a much more constant rate throughout the year than do residential large volume customers; i.e., small volume customer's usage is more constant throughout the year.

To illustrate, on a weather normalized basis, KU's average residential customer uses about 1,555 kWh during the winter months of January and February and about 1,276 kWh during the summer months of July and August. However, during the Spring and Fall months of April, May, October, and November, the average residential customer uses only about 912 kWh.[45] As a result, the load factor of small volume (non-heating/air conditioning customers) tends to be much higher than that for large volume (heating/air conditioning customers). As a matter of cost causation, the Companies must plan and install relatively more capacity for heating/air conditioning customers than for small

[45] Per AG-KIUC 1-180.

volume customers. This additional capacity obviously comes at a cost such that the cost to serve a high load factor (low annual volume) customer is significantly less than that for a low load factor (high annual volume) customer.

The second aspect concerns the pricing structure of goods and services generally, and public utility rates specifically. That is, taken to the extreme, it could be argued that every consumer of a good or service (whether competitive or regulated) imposes a different cost upon the good or service provided such that a different price could theoretically be calculated for every individual customer. This of course is not done in practice as it is not practical or reasonable. For example, if two customers purchase gasoline from a gas station at the same time, one driving a very large vehicle with a large fuel tank and the other driving a very small car with a small fuel tank, the customer purchasing a small amount of gasoline does not pay more per gallon than the customer purchasing significantly more gasoline. This is true even though the ultimate delivered price of gasoline includes a significant level of "fixed" costs such as the cost of the store, gas pumps, labor, etc.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH THE COMPANIES' RESIDENTIAL ELECTRIC CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO KU'S AND LG&E'S ELECTRIC RESIDENTIAL CLASSES?

A. Yes. I conducted a direct customer cost analyses for KU's and LG&E's electric residential classes separately. The details of these analyses are provided in my Schedule GAW-25. As indicated in this Schedule, the residential direct customer cost is at most $4.57 per month for KU and $4.15 per month for LG&E. It should be noted that my customer cost analyses is based on the Companies' proposed return on equity of 10.00%. If a lower cost of equity is used, the resulting customer costs are somewhat reduced.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all utilities, the Companies are in the business of providing electricity and natural gas to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to the Companies' services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric charges.

Q. MR. SEELYE CLAIMS THAT HIS "COST-BASED" ELECTRIC RESIDENTIAL CUSTOMER CHARGE IS $24.94 PER MONTH FOR KU AND $20.99 PER MONTH FOR LG&E. PLEASE EXPLAIN HOW MR. SEELYE ARRIVED AT THESE LEVELS.

A. Mr. Seelye's figures include a portion of distribution plant investment costs associated with poles, overhead lines, underground conductors, conduit, and transformers. In addition, his calculated residential customer costs includes an assignment of intangible plant and general plant. With regard to O&M expenses, Mr. Seelye has included a large portion of administrative and general expenses as well as other overhead expenses. Finally, Mr. Seelye's customer cost analysis includes the entire amount of uncollectible expenses. These costs should not be reflected within the determination of an appropriate fixed customer charge.

Q. IN TERMS OF MAGNITUDE, WHAT LEVEL OF COSTS HAS MR. SEELYE CLASSIFIED AS "CUSTOMER-RELATED" AND INCLUDED WITHIN HIS ELECTRIC CUSTOMER COST DETERMINATION?

A. On a total Company basis, Mr. Seelye has included the following electric costs in his customer analyses:

TABLE 34
KU
Seelye Inappropriate Costs Included in "Customer Costs"
($ Millions)

	Customer Amount	Total Company	Customer % Of Total
Rate Base:			
Gross Intangible Plant	$14,396	$105,751	13.6%
Gross OH Lines & Poles	$589,854	$921,791	64.0%
Gross UG Lines	$185,467	$247,686	74.9%
Gross Transformers	$148,192	$326,559	45.4%
Gross General Plant	$33,341	$244,919	13.6%
Plant Held for Future Use	$526	$907	58.1%
Construction Work in Progress	$19,227	$155,824	12.3%
Cash Working Capital	$17,795	$130,078	13.7%
Materials & Supplies	$8,155	$59,891	13.6%
Prepayments	$2,590	$19,024	13.6%
Total Rate Base	$1,019,544	$2,212,429	46.1%
O&M Expenses:			
OH Lines-Operations	$4,222	$6,598	63.99%
Misc. Distribution Expenses	$4,931	$8,492	58.06%
Maintenance of OH Lines	$17,963	$28,072	63.99%
Maintenance of UG Lines	$362	$483	74.88%
Maintenance of Transformers	$48	$106	45.33%
Uncollectible Expense	$4,646	$4,646	100.00%
Customer Service Expenses	$5,261	$5,261	100.00%
Administrative & General	$30,780	$112,306	27.41%
Total O&M Expenses	$68,213	$165,964	41.10%

TABLE 35
LG&E
Seelye Inappropriate Costs Included in "Customer Costs"
($ Millions)

	Customer Amount	Total Company	Customer % Of Total
Rate Base:			
Gross Intangible Plant	$0	$2	18.18%
Gross OH Lines & Poles	$437,842	$684,236	63.99%
Gross UG Lines	$284,955	$476,036	59.86%
Gross Transformers	$65,167	$182,077	35.79%
Gross General Plant	$3,514	$21,026	16.71%
Plant Held for Future Use	$1,644	$2,909	56.50%
Construction Work in Progress	$11,411	$67,177	16.99%
Cash Working Capital	$15,129	$124,454	12.16%
Materials & Supplies	$7,383	$44,127	16.73%
Prepayments	$2,458	$14,688	16.73%
Total Rate Base	$829,503	$1,616,732	51.31%
O&M Expenses:			
OH Lines-Operations	$3,701	$5,784	63.99%
UG Lines-Operations	$3,784	$6,321	59.86%
Misc. Distribution Expenses	$4,179	$7,396	56.50%
Maintenance of OH Lines	$10,091	$15,769	63.99%
Maintenance of UG Lines	$1,110	$1,854	59.86%
Maintenance of Transformers	$66	$186	35.80%
Uncollectible Expense	$2,226	$2,226	100.00%
Customer Service Expenses	$3,423	$3,423	100.00%
Administrative & General	$20,457	$86,141	23.75%
Total O&M Expenses	$49,036	$129,099	37.98%

Q. WHY IS IT INAPPROPRIATE TO INCLUDE A PORTION OF ELECTRIC DISTRIBUTION OVERHEAD LINES, UNDERGROUND LINES, AND TRANSFORMER COSTS IN THE DETERMINATION OF REASONABLE FIXED CUSTOMER CHARGES?

A. Every electric utility's investment in distribution lines and transformers reflects the backbone of the company's distribution system and indeed, serves as the infrastructure supporting the company's entire existence. In other words, distribution lines and transformers are the conduit to move electricity from the transmission system to individual customers. Residential customers do not subscribe to the Companies' service simply to be "connected," rather, they rely upon the Companies to distribute their energy requirements throughout the year.

Q. MR. SEELYE ASSERTS THAT THE COSTS ASSOCIATED WITH THE MINIMUM SYSTEM ARE APPROPRIATE IN THE DETERMINATION OF CUSTOMER CHARGES. PLEASE RESPOND TO THIS ASSERTION.

A. On pages 18 and 19 of his direct testimony, Mr. Seelye states:

> A cost of service study is performed for the purpose of allocating costs as accurately as possible based on cost causation. In a cost of service study, it is important to distinguish the distribution system costs related to demand from the distribution system costs that are related to the minimum system that are not related to demand, as discussed in the NARUC *Electric Cost Allocation Manual*.

In this regard, Mr. Seelye is confusing the manner in which joint costs are allocated to classes as compared to how rates should be designed and collected from customers. The reason that some distribution costs are reasonably allocated to various customer classes has nothing to do with cost causation per se, but rather, due to differences in densities across customer classes.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT DISTRIBUTION POLES, LINES, AND TRANSFORMERS SHOULD NOT BE CONSIDERED AS "CUSTOMER-RELATED" COSTS FOR PURPOSES OF DETERMINING THE REASONABLENESS OF FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. In his well-known treatise <u>Principles of Public Utility Rates</u>, Professor James C. Bonbright states:

> . . . if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of

> their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customers costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories. (Second Edition, page 492)

Q. EARLIER YOU NOTED THAT MR. SEELYE CONFUSES THE CONCEPT OF COST ALLOCATION WITH RATE DESIGN. IN THERE A NARUC PUBLICATION THAT DISCUSSES THE DETERMINATION OF RESIDENTIAL CUSTOMER CHARGES FOR RATE DESIGN PURPOSES?

A. Yes. In a NARUC Publication entitled <u>Charging for Distribution Utility Services: Issues in Rate Design</u>, the authors found as follows as it relates to the determination of fixed monthly customer charges:

> As one moves along the continuum of rate designs from usage-based to fixed, the benefits of the former give way more and more to the difficulties of the latter. This is the kind of trade-off that commissions are often faced with balancing: our analysis concludes that the balance strongly favors a rate structure that allows consumers to avoid charges, when there cost-effective alternatives that they value more highly. Usage-based rates fit this bill; so do hook-up fees (page 46).

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR KU AND LG&E'S RESIDENTIAL CUSTOMERS?

A. Although my customer cost analysis indicates that electric residential customer charges of no more than \$4.57 per month for KU and \$4.15 for LG&E are warranted, I recommend that the current electric residential customer charges for both KU and LG&E be maintained at their current levels of \$16.12 per month, or \$0.53 per day for KU and \$13.69 per month, or \$0.45 per day for LG&E Electric.

Maintaining the current customer charges will promote rate continuity as well as promoting conservation as any increase authorized in this case will be collected from residential energy charges, thereby sending a more appropriate price signal for customers to conserve and use energy more efficiently.

By maintaining the current electric customer charges of $16.12 (KU) and $13.69 (LG&E) per month, leaves at least $11.55 for the recovery of non-direct customer-related costs including overhead and other costs for KU and $9.50 for LG&E's electric operations.

2. Residential Demand Charges

Q. ON PAGE 15 OF HIS DIRECT TESTIMONY, MR. SEEYLE STATES THAT "SEVERAL UTILITIES IN THE U.S. HAVE IMPLEMENTED THREE- AND MULTI-PART RATES FOR RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS. THIS IS A TREND IN THE INDUSTRY THAT I BELIEVE THE COMPANIES AND THE COMMISSION SHOULD CLOSELY MONITOR." PLEASE COMMENT ON THIS STATEMENT.

A. Mr. Seeyle claims that these approaches are being implemented by utilities. In this regard, Mr. Seeyle is mischaracterizing the implementation of demand-based rates (three-part rates) for residential customers. While residential demand-based rates are available as an option by several utilities, this is not the case for the mandatory demand-based rates for residential customers. Although mandatory demand charges have been proposed by a handful of utilities throughout the United States, not a single one has been approved. Typical residential customers do not understand the concept of power versus energy usage and therefore, do not understand the concept of demand charges. As a result and universally, residential customers have expressed nothing short of outrage over utilities' proposals to implement mandatory demand charges. Indeed, this Commission needs to look no further than Glasgow, Kentucky as it relates to the mandatory residential demand charge initially implemented by the Glasgow Electric Plant Board. This utility initially implemented mandatory residential demand charges (which is not subject to this Commission's jurisdiction). Almost immediately, there was public outcry relating to these mandatory demand charges. As a result, the utility was forced to continue offering energy only-based rates. Other examples include mandatory demand charge proposals in Arizona that were supported by the Commission Staff. Once again, there was as much public outcry against this change as has ever been seen. Ultimately, the Arizona

Corporation Commission denied the utilities' request for mandatory residential demand charges.

Q. WHY ARE SOME UTILITIES ADVOCATING MANDATORY RESIDENTIAL DEMAND CHARGES?

A. Maximum peak load (demand) is considerably more inelastic than energy consumption; i.e., a customer's total demand will not vary as much as its energy consumption regardless of a consumer's attempts to reduce consumption or engage in conservation practices. As a result, this creates more guarantee of revenue recovery to the utility, which in turn, reduces the utility's risks.

Q. DO KU AND LG&E CURRENTLY HAVE ALTERNATIVE RESIDENTIAL RATE DESIGN OPTIONS AVAILABLE TO ITS CUSTOMERS?

A. Yes. Both KU and LG&E offer an optional Time of Day energy-based rate schedule as well as an optional demand-based rate schedule. For KU, there are currently only 6 customers subscribed to the demand-based rate schedule and 99 customers subscribing to the Time of Day energy-based rate schedule. For LG&E, there are currently only 12 customers subscribed to the demand-based rate schedule and 138 customers subscribing to the Time of Day energy-based rate schedule.[46] This lack of participation is evidence of the fact that residential customers do not like nor do they want demand-based rates. In this regard, this is a very important public policy issue. That is, in competitive markets, consumers (the market) dictate how pricing structures are developed. However, public utilities are monopolists and consumers have no other option for these public goods and services. Under the tried and true energy only-based rates, utilities have, and will continue to have, the realistic opportunity to recover their costs and provide a reasonable profit to their shareholders. As such, these proposals advocated by KU, LG&E and other utilities are nothing more than a red herring in that the utilities are using these rate design approaches to reduce their risk and increase shareholder value at the expense of the consuming public.

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[46] As of December 2020 per response to AG-KIUC-180.

III. LG&E'S NATURAL GAS OPERATIONS

A. Natural Gas CCOSS

Q. WITH REGARD TO NATURAL GAS LDCs, ARE THERE ANY ASPECTS OF CLASS COST ALLOCATIONS THAT TEND TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. The area of cost allocation that tends to overshadow all other issues relates to the classification and allocation of distribution mains such that the methodology employed and selection of external allocators for this account (Account 376) has a profound impact on the ultimate calculated class RORs. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution mains.

Q. WHAT METHODS ARE COMMONLY USED TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS?

A. While a myriad of cost allocation methods and approaches have been developed, three (3) methods predominate in the natural gas LDC industry: "peak responsibility," "Peak and Average" and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing mains investments. There are three criteria generally considered when selecting a mains cost allocation method: peak demand (whether coincident, non-coincident, actual, or design day); annual (average day) usage; and, number of customers. Because a LDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of mains investment.[47] Annual (or average day) throughput is also often used to allocate mains as this factor reflects the utilization of a utility's mains investment. Number of customers is also sometimes considered when

[47] Embedded cost allocations are directly only concerned with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that are relevant.

allocating mains. That is, customer counts by class serve as a basis for allocation mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weight and utilize these criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

As noted above, the three most common natural gas LDC cost allocation methods are: the "peak responsibility" method (whether coincident or class non-coincident) in which peak day demands are the only factor utilized to allocate mains; the "Peak and Average" approach in which both peak day and annual (average day) throughput is reflected within the allocation of mains;[48] and the Customer/Demand method that utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Under the Customer/Demand method, the weights given to class customer counts and peak day demands are determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. The second approach used to classify and allocate mains based partially on customers and partially on peak demand is known as the "zero-intercept" method. Under this approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" main. Similar to the minimum size approach, the cost of this estimated zero size pipe per foot is

[48] Under the Peak and Average or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is the ratio of average daily usage to peak day usage. When using a load factor approach to weight Peak and Average usage, the weighting of average day usage is that of the system load factor while the peak day weight is one minus the system load factor.

multiplied by the total system footage and is then divided by total mains investment to arrive at a customer weighting.

Q. WHICH METHOD DID THE COMPANY USE TO ALLOCATE COSTS TO CUSTOMER CLASSES FOR THIS CASE?

A. Company witness Seelye conducted his cost study utilizing the Customer/Demand method to allocate distribution mains.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. The Peak and Average approach is the most fair and equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

Q. HOW APPROPRIATE IS A CUSTOMER/DEMAND SEPARATION FROM A DESIGN OR OPERATIONAL PERSPECTIVE?

A. First and foremost, the classification of distribution plant as partially customer, and partially demand-related results from the view that the assignment of these plant items to classes based solely on a demand allocator would not be equitable to some classes. I emphasize this point, because many analysts "lose sight of the forest for the trees." When classifying individual accounts within distribution plant, analysts sometimes do not consider how a distribution system is designed and connected.

There are several major factors the analyst should keep in mind when classifying natural gas distribution plant. First is the fact that purchasing economies are usually present. For example, there are many types and sizes of pipe manufactured. However, due to purchasing economies, a utility may purchase only a few different sizes of pipe. This will result in some "over capacity," however, the total installed cost will be less than if every segment of the system is optimally sized. Second, most components of the distribution system are somewhat oversized for other reasons, such as pressure equalization, safety, reliability, and growth uncertainty. Third, historical asset records reflecting capitalized labor and material costs by size and type of investment are far from perfect.[49] These asset records are the underlying source for conducting minimum size and zero-intercept studies. Fourth, and particularly relevant to most natural gas LDC's including LG&E is that it generally costs significantly more to install and maintain mains pipes in more urban (densely populated) areas of the Company's service area than in its more suburban (less densely populated) areas. This is because of the infrastructure within, and adjacent to, mains rights-of-way as well as the predominant types of pipe used in various areas. In the more urban parts of a service area, mains are generally buried under roads and sidewalks creating significantly higher costs than suburban areas in which a single trench along a road-side is often the only thing necessary. Moreover, due to the size of pipes required as well as safety needs, larger pipes in the suburban areas tend to be steel as opposed to much cheaper plastic pipe.

Although these factors are reflective of how distribution systems are actually installed and operated, classification studies do not account for these factors. In fact, the presence of these factors can seriously skew the results of such studies.

Q. SHOULD PEAK DAY DEMANDS BE THE ONLY CONSIDERATION WHEN ALLOCATING NATURAL GAS DISTRIBUTION MAINS?

A. No. Perhaps the most fundamental aspect of cost allocation is the desire to reasonably assign costs (plant and expenses) based on cost causation. As indicated earlier, while it is appropriate to consider and reflect class peak demands when allocating distribution mains, it should not be the only criteria. An LDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If LG&E's (or any natural gas LDCs) customers only demanded gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, LG&E's customers' demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it

[49] Reasons for less than perfect record keeping include: the loss of data over time, the changing needs of recordkeeping by a Company, data processing limitation, different record keeping practices and detail by companies prior to mergers/acquisition by other companies.

would be prohibitively expensive to the Company (and ultimately the customer) to provide service as the investment in mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically unfeasible.

Q. IS LG&E'S "MAINS EXTENSION" POLICY CONSISTENT WITH THE REALITY THAT CUSTOMERS UTILIZE NATURAL GAS THROUGHOUT THE YEAR AND NOT ON JUST A SINGLE DAY?

A. Yes. When LG&E evaluates a main extension proposal or project, it considers the maximum load that will be placed on the extension as well as the annual usage of the main extension in determining customer or developer contribution requirements.[50]

Q. EVEN THOUGH MAINS ARE INSTALLED TO MEET THE NATURAL GAS ENERGY NEEDS OF CUSTOMERS THROUGHOUT THE YEAR AND IT WOULD BE PROHIBITIVELY EXPENSIVE TO SERVE A CUSTOMER FOR ONLY ONE DAY PER YEAR, DOES IT COST MORE TO INSTALL A MAIN WITH HIGHER PEAK DEMANDS PLACED UPON IT THAN ANOTHER SEGMENT WITH LOWER PEAK DAY DEMAND REQUIREMENTS?

A. While this is correct as a broadly general statement, there is not a direct and linear relationship between peak demands (capacity requirements) and costs. This is the most important concept. That is, if one were to consider allocating the cost of mains based on the physical relationships of peak day demand (load) one must evaluate whether <u>costs</u> increase proportionally and in a linear manner with <u>peak load</u>. In reality, if the peak load on one line segment of mains is double that of another line segment, the cost of mains for a higher capacity pipe (to meet these additional costs) may be higher but is not double that of the lower capacity main. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates mains entirely on peak day demand) because it is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads (demand), system capacity, and costs. With regard to system capacity, the amount of gas that can be delivered throughout a LDC system is not

[50] LG&E's Tariff, Terms and Conditions, Sheet 106.

only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. In very simple terms, and all else constant, the *capacity* of pipes increases by a factor of exactly 4 to 1 as the diameter of pipe increases.[51] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[52]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. This fact is most relevant for cost allocation purposes for older LDC's with large mains replacement programs. With increases in materials, technology, and pipe coupling improvements, we are seeing that LDCs are replacing their systems with smaller plastic pipes operated at higher pressures. For example, based on current pipe manufacturing specifications, a 2-inch plastic pipe operating at 60 pounds per square inch gauge ("psig") has approximately 3.6 times the capacity of a 4-inch plastic line operating at low pressures (less than 1psig). Because the allocation of mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load by definition assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of mains. This assumption is clearly not accurate.

Q. SINCE THERE IS NOT A DIRECT AND LINEAR RELATIONSHIP BETWEEN PEAK LOAD REQUIREMENTS AND THE COST OF MAINS, IS THERE A COST ALLOCATION METHOD THAT REASONABLY REFLECTS THE COST CAUSATION OF MAINS?

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[51] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[52] The cost of mains investment reflects the cost of capitalized labor to install the main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

A. Yes. When properly applied, the Peak and Average (Demand/Commodity) method reasonably and fairly models the economies of scale reflected in mains investment. If all customers (and classes) demanded and utilized natural gas at a consistent rate throughout the year, LG&E's LDC system would be comprised of smaller size mains. Obviously, such is not the case in that LG&E's peak (design day) demands are about 5.0 times that of its average day firm service demands.[53] Even though the increased capacity required to serve design day peak loads is about five times that required for average day loads, the actual cost of mains is smaller than this relationship. As such, a cost allocation method which allocates about half of LG&E's mains costs based on average demand and the remaining half on peak demand serves as a reasonable proxy for cost causation and fairly assigns class cost responsibility. To summarize, the allocation of mains solely on peak demands does not reflect cost causation due to the economies of scale present in meeting the capacity (design day) needs of the company's distribution system; i.e., as peak demand increases, costs increase at a decreasing rate.

Q. DID YOU FIND MR. SEELYE'S NATURAL GAS CCOSS MODEL TO BE MATHEMATICALLY ACCURATE?

A. Yes. As a result, I was able to utilize Mr. Seelye's natural gas Excel model for purposes of my analysis in this case.

Q. WHAT ARE THE END-RESULTS OF MR. SEELYE'S CLASSIFICATION OF MAINS AS IT APPLIES TO HIS CCOSS?

A. Mr. Seelye bifurcates mains between low/medium pressure and high pressure. With regard to low/medium pressure mains, Mr. Seelye has classified this investment based on a weighting of 68.70% on number of customers and 31.30% on design day demands. With regard to high pressure mains, Mr. Seelye has classified this investment based on a weighting of 47.43% on number of customers and 52.57% on design day

[53] Per Company CCOSS. Total design day demand is 606,908 MCF, whereas average day demand is 119,221 MCF.

demands. On a combined basis, Mr. Seelye's distribution mains classification results in 66.71% customer-related and 33.29% demand-related.[54]

What this means is that for about two-thirds of the Company's cost of mains, the same dollar amount is allocated to a small non-heating apartment customer as is assigned to a huge industrial factory that uses millions of MCF per year and that only about one-third of the Company's largest single investment (distribution mains) is utilized to serve customers with varying load and usage requirements. By any standard, this is grossly unreasonable and simply does not pass any informed or even common sense "smell test."

Q. DOES MR. SEELYE'S CLASSIFICATION OF DISTRIBUTION MAINS RESULT IN A BIAS TO ANY PARTICULAR CLASSES IN HIS CUSTOMER/DEMAND CCOSS?

A. Yes. Mr. Seelye's Customer/Demand split of mains severely over-allocates cost to the Residential class since this class represents more than 92% of the number of customers but only about 53% of design day demand relating to high pressure mains and 63% of design day demand relating to low/medium pressure mains. At the same time, the Residential class accounts for only about 41% of system annual throughput (usage). As such, Mr. Seelye's classification of mains significantly over-assigns mains and mains-related costs to the Residential class. Furthermore, because many other rate base and expense items are allocated to classes based on the previous allocation of mains investment, Mr. Seelye's bias has a compounding effect on the total costs allocated to each class.

Q. HAVE YOU CONDUCTED CCOSS THAT UTILIZE MORE REASONABLE ALLOCATION METHODS AND MORE REASONABLY REFLECT COST CAUSATION?

A. Yes. I have conducted two alternative CCOSS. The first utilizes my preferred method to allocate distribution mains (i.e., the P&A method based on 50% design day demands and 50% on average day demands). The second method utilizes the Peak

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[54] There is much more investment associated with low/medium pressure mains ($445.6 million) than high pressure mains ($46.1 million).

Responsibility method to allocate distribution mains wherein these costs are classified and allocated as 100% demand-related.[55] A comparison of the Company's and my CCOSS RORs at current rates is provided in the table below:

TABLE 36
ROR At Current Rates

Class	Seelye Customer/ Demand	OAG P&A	OAG 100% Demand
Residential (RGS)	4.62%	6.62%	6.29%
Commercial (CGS)	7.56%	4.28%	4.22%
Industrial (IGS)	13.70%	4.60%	6.92%
As Available Gas (AAGS)	-3.24%	-5.72%	-5.32%
Firm Transportation (FT)	-1.75%	-3.70%	-2.80%
Total	5.10%	5.10%	5.10%

The details of my P&A CCOSS are provided in my Schedule GAW-26 through Schedule GAW-28. A summary of my Peak Responsibility (100% demand) CCOSS is provided in my Schedules GAW-29. In this regard, the format for my Peak Responsibility method is identical to that of my P&A study wherein the details of the Peak Responsibility method are provided in my filed workpapers.

Q. HAS THIS COMMISSION PROVIDED GUIDANCE REGARDING THE METHODOLOGIES TO BE EMPLOYED FOR NATURAL GAS CLASS COST OF SERVICE STUDIES?

A. Yes. In a litigated rate case involving Atmos Energy Corporation (Case No. 2013-00148) wherein the Company utilized the Customer/Demand approach and I utilized the same P&A approach recommended in this case, the Commission found:

> "that a Peak and Average COSS such as the AG proposed reflects a reasonable methodology. However, we also find the methodology used by Atmos-Ky to be reasonable . . . ."[56]

[55] I have utilized Mr. Seelye's CCOSS model and also accepted and reflected the bifurcation of distribution mains between low/medium pressure and high-pressure mains.
[56] Case No. 2013-00148, Final Order, page 33, April 22, 2014.

B. LG&E Gas Class Revenue Distribution

Q. PLEASE PROVIDE A SUMMARY OF MR. SEELYE'S PROPOSED CLASS REVENUE INCREASES FOR LG&E'S GAS OPERATIONS.

A. The following table provides a summary of current and Mr. Seelye's proposed margin revenues by rate class for LG&E gas:

TABLE 37
LG&E Gas Proposed Class Revenue Increases
($000)

Rate Class	Margin Revenue At Current Rates[57]	Proposed Increase	% Increase In Margin Revenue
Residential (Rate RGS & VFD)	$164,832.3	$22,318.2	13.54%
Commercial (Rate CGS)	$62,240.3	$4,911.9	7.89%
Industrial (Rate IGS)	$4,962.0	$0.0	0.00%
As-Available (Rate AAGS)	$240.4	$109.5	45.54%
Firm Transportation (Rate FT)	$6,618.5	$2,630.9	39.75%
Special Contract	$2,261.6	$1.6	0.07%
Distributed Generation (Rate DGGS)	$19.9	-$1.9	-9.52%
Substitute Gas Sales – Comm. (Rate SGSS)	$184.5	$9.2	4.97%
Total Rate Revenue	$241,359.5	$29,979.3	12.42%
Other Revenue	$1,372.9	$8.8	0.64%
Total LG&E	$242,732.4	$29,988.1	12.35%

It should be noted that Mr. Seelye's testimony and exhibits include Gas Supply Clause and DSM Rider revenues that are guaranteed recovery mechanisms and are therefore not subject to the margin increases requested by LG&E in this case. In addition, transportation customers do not purchase gas from LG&E such that Mr. Seelye's representation of increases to transportation customers are distorted. Therefore, margin revenues better reflect the true increases across classes.

Q. ARE MR. SEELYE'S PROPOSED CLASS REVENUE INCREASES REASONABLE FOR LG&E GAS?

[57] Includes base rate plus gas line tracker revenues. Excludes Gas Supply and DSM Tracker revenues.

A. No. Although Mr. Seelye gave considerable weight to his CCOSS results, his proposed class revenue increases are unreasonable for two reasons. First, Mr. Seelye relied exclusively on his Customer/Demand method to allocate mains which significantly over assigns cost responsibility to the residential class. Second, and as shown in Table 37, Mr. Seelye proposes exceptionally large increases for Rates AAGS and FT. These very large percentage increases are in conflict with reasonable gradualism principles.

Q. DO YOU RECOMMEND ALTERNATIVE GAS CLASS REVENUE INCREASES TO THOSE PROPOSED BY MR. SEELYE?

A. Yes. In developing my recommended class revenue distribution I considered gradualism as well as recognized movement towards cost of service. In developing my recommendation, I have relied primarily on the results of my P&A and Peak Responsibility (100% demand) CCOSS results and also considered Mr. Seelye's Customer/Demand results as shown in my Table 36.

As indicated in my Table 36, all studies indicate that the As-Available Gas (Rate AAGS) and Firm Transportation (Rate FT) classes are significantly revenue deficient in that they are producing negative RORs. Mr. Seelye proposes to increase these rate schedules by 45.54% and 39.75%, respectively. However, such large increases do not reasonably reflect gradualism. Therefore, I recommend that Rates AAGS and FT be increased at 150% of the system average percentage increase.

With regard to Industrial Gas Service (Rate IGS), Mr. Seelye's Customer/Demand shows that this class's ROR is significantly above the system average ROR. However, my P&A study indicates that this class is somewhat revenue deficient while my Peak Responsibility study indicates that this class is producing an ROR slightly above the system average ROR. As a result, and recognizing all three CCOSS results, I recommend that Rate IGS be increased at the remaining average percentage increase.

Mr. Seelye's CCOSS indicates that Rate CGS is producing an ROR somewhat above the system average such that he recommends a smaller percentage increase to this rate than the system average. However, my studies indicate that this class is somewhat revenue deficient such that I recommend that this rate be increased at the remaining average percentage increase.

With regard to the residential class, Mr. Seelye's study indicates that this class's ROR is somewhat below the system average ROR and therefore proposes to increase this class' margin revenues with a somewhat higher percentage increase than the system average. At the same time, my two CCOSS indicate that the residential class' ROR is above the system average. I recommend that the residential class be increased at the remaining average percentage increase.

With regard to Distributed Generation (Rate DDGS) and Substitute Gas Sales (Rate SGSS), these are not separate classes in the CCOSS and therefore there is no cost basis for Mr. Seelye's proposed 9.52% reduction to Rate DDGS margin revenues or his 4.97% increase to Rate SGSS margin revenues. Given this, I recommend that Rates DDGS and SGSS be increased at the remaining average percentage increase.

Finally, with regard to what has been designated as the Special Contract rate, it is my understanding that this is service provided for intra-company services. Similar to Rate DDGS, there is no cost information related to this customer such that I recommend that this class be increased at the remaining average percentage increase. My recommended LG&E gas class revenue increases are provided in the table below:

TABLE 38
OAG Proposed Gas Class Revenue Increases
($000)

Rate Class	Margin Revenue At Current Rates	OAG Proposed $ Increase	OAG Proposed % Increase
Residential (Rate RGS & VFD)	$164,832.3	$20,174.4	12.24%
Commercial (Rate CGS)	$62,240.3	$7,617.8	12.24%
Industrial (Rate IGS)	$4,962.0	$607.3	12.24%
As-Available (Rate AAGS)	$240.4	$44.8	18.63%
Firm Transportation (Rate FT)	$6,618.5	$1,233.1	18.63%
Special Contract	$2,261.6	$276.8	12.24%
Distributed Generation (Rate DGGS)	$19.9	$2.4	12.24%
Substitute Gas Sales – Comm. (Rate SGSS)	$184.5	$22.6	12.24%
Total Rate Revenue	$241,359.5	$29,979.3	12.42%
Other Revenue	$1,372.9	$8.8	0.64%
Total LG&E	$242,732.4	$29,988.1	12.35%

C. **<u>Natural Gas Residential Rate Design</u>**

Q. DOES MR. SEELYE PROPOSE TO INCREASE THE FIXED RESIDENTIAL GAS CUSTOMER CHARGE?

A. Yes. Witness Seelye proposes the following increase to LG&E's gas residential customer charge:

TABLE 39
Gas Residential Customer Charges

	Current Rate		Proposed Rate		Monthly	Percent
	Daily	Monthly	Daily	Monthly	Increase	Increase
LG&E	$0.65	$19.77	$0.78	$23.73	$3.96	20.0%

Q. DOES MR. SEELYE USE THE SAME RATIONALE FOR HIS PROPOSED INCREASES TO NATURAL GAS FIXED CUSTOMER CHARGES AS HE DOES FOR ELECTRIC CUSTOMER CHARGE INCREASES?

A. Yes. His rationale and arguments are the same for gas as they are for electric.

Q. ARE YOU DISAGREEMENTS WITH MR. SEELYE THE SAME FOR NATURAL GAS AS THEY ARE FOR THE COMPANIES ELECTRIC OPERATIONS?

A. Yes.

Q. MR. SEELYE CLAIMS THAT HIS "COST-BASED" NATURAL GAS RESIDENTIAL CUSTOMER CHARGE IS $0.98 PER DAY OR $29.81 PER MONTH. PLEASE EXPLAIN HOW MR. SEELYE ARRIVED AT THESE LEVELS.

A. Mr. Seelye's figures include a portion of distribution plant investment costs associated with distribution mains. In addition, his calculated residential customer costs includes an assignment of intangible plant and general plant. With regard to O&M expenses, Mr. Seelye has included a large portion of administrative and general expenses as well as other overhead expenses. Finally, Mr. Seelye's customer cost analysis includes the entire amount of uncollectible expenses. These costs should not be reflected within the determination of an appropriate fixed customer charge.

Q. IN TERMS OF MAGNITUDE, WHAT LEVEL OF COSTS HAS MR. SEELYE CLASSIFIED AS "CUSTOMER-RELATED" AND INCLUDED WITHIN HIS NATURAL GAS CUSTOMER COST DETERMINATION?

A. On a total Company basis, Mr. Seelye has included the following natural gas costs in his customer analyses:

TABLE 40
LG&E Gas
Seelye Inappropriate Costs Included in "Customer Costs"
($ Millions)

	Customer Amount	Total Company	Customer % Of Total
Rate Base:			
Gross Distribution Mains	$328,015	$491,696	66.71%
Gross Ind. Meas. & Reg. Equip.	$2,156	$2,156	100.00%
Gross Other Equipment	$1,990	$1,990	100.00%
Gross General Plant	$9,545	$16,821	56.75%
Gross Common Plant	$58,936	$103,861	56.75%
Construction Work in Progress	$14,892	$49,996	29.79%
Cash Working Capital	$14,655	$29,498	49.68%
Materials & Supplies	$915	$1,613	56.75%
Prepayments	$2,307	$4,065	56.75%
Total Rate Base	$433,411	$701,696	61.77%
O&M Expenses:			
Mains/Services Expenses	$8,116	$9,886	82.10%
Other Distribution Expenses	$6,250	$7,924	78.88%
Rents	$21	$27	78.88%
Maintenance of Mains	$8,027	$12,033	66.71%
Maint. of Ind. Meas. & Reg.	$306	$306	100.00%
Maint. of Other Equipment	$442	$560	78.88%
Uncollectible Expense	$472	$472	100.00%
Customer Service Expenses	$1,302	$1,302	100.00%
Sales Expense	$16	$16	100.00%
Administrative & General	$14,227	$27,735	51.29%
Total O&M Expenses	$39,179	$60,261	65.02%

Q. HAVE YOU CONDUCTED A DIRECT CUSTOMER COST ANALYSIS APPLICABLE TO LG&E'S NATURAL GAS RESIDENTIAL CLASS?

A. Yes. I conducted a direct customer cost analysis for LG&E's natural gas residential class. The details of this analysis are provided in my Schedule GAW-30. As indicated in this Schedule, the residential direct customer cost is at most $13.11 per month ($0.43 per day). Similar to my electric customer cost analysis, my natural gas customer cost analysis is based on the Company's proposed rate of return on equity of 10.00%. If a lower cost of equity is used, the resulting customer cost is somewhat reduced.

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR LG&E RESIDENTIAL NATURAL GAS CUSTOMERS?

A. Although my customer cost analysis indicates that natural residential customer charges of no more than $13.11 per month are warranted, I recommend that the current natural gas residential customer charge for LG&E be maintained at its current level of $19.77 per month, or $0.65 per day.

Maintaining the current customer charges will promote rate continuity as well as promoting conservation as any increase authorized in this case will be collected from residential energy charges, thereby sending a more appropriate price signal for customers to conserve and use energy more efficiently.

By maintaining the current natural gas customer charge of $19.77 per month, leaves at least $6.66 for the recovery of non-direct customer-related costs including overhead and other costs.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.