COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: **ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY**	)))))))))	**Case No. 2016-00371**

Direct Testimony and Exhibit of

James T. Selecky

On behalf of

United States Department of Defense
and all other Federal Executive Agencies

March 3, 2017

BRUBAKER & ASSOCIATES, INC.

Project 10359

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**Case No. 2016-00371**

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

VERIFICATION OF JAMES T. SELECKY

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

James Selecky
James T. Selecky

SUBSCRIBED and SWORN to before me this 2nd day of March, 2017.

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

Tammy S Klossner
Notary Public

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**Case No. 2016-00371**

TABLE OF CONTENTS TO THE DIRECT TESTIMONY OF JAMES T. SELECKY

I. INTRODUCTION **1**

II. SUMMARY AND CONCLUSIONS **2**

III. ELECTRIC COST OF SERVICE STUDIES **3**

IV. TIME-OF-DAY PRIMARY SERVICE ("TODP") **12**

V. SUBSTITUTE GAS SALES SERVICE ("SGSS") **19**

VI. QUALIFICATIONS OF JAMES T. SELECKY ..... **APPENDIX A**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: **ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY**	**Case No. 2016-00371**

DIRECT TESTIMONY OF JAMES T. SELECKY

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA"). The DoD/FEA takes service from Louisville Gas and Electric Company ("LG&E" or "Company") on several electric rate schedules. In addition, Fort Knox takes gas service from LG&E on Commercial Gas Service ("CGS") rate schedule. .

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony will address cost of service, revenue allocation and rate design for DoD/FEA electric service. I will also address the proposed electric Time-of-Day Primary and the Substitute Gas Sales Service rates. My colleague, Christopher Walters, will be addressing the appropriate rate of return that the Kentucky Public Service Commission ("Commission") should utilize to determine LG&E's revenue requirement and revenue deficiency. The fact that I have not addressed an issue should not be construed as an endorsement of LG&E's position.

II. SUMMARY AND CONCLUSIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations can be summarized as follows:

1. LG&E has presented two versions of the electric cost of service study. The Commission should rely on the results of the Loss of Load Probability ("LOLP") cost of service study for the allocation of any increase.

2. The LG&E's proposed Time-of-Day Primary Service rate ("TODP") cost recovery from the base, intermediate and peak demand charges should be adopted by the

Commission. However, the level of charges will be a function of the revenue requirement and allocation of any increase that the Commission ultimately approves.

3. For TODP, the proposed rate design reduces the base demand charge while increasing the intermediate and peak demand charges. This is more reflective of the results of LOLP cost of service study, and consistent with the price signals that a time-of-day rate should send.

4. The TODP rate should provide a discount for customers taking service at 34,500 volts. The rate as proposed does not differentiate between customers who are taking service at 34,500 volts, 2,400/4,160 volts and 7,200/12,470 volts. As a result the 34,500 kV customers are subsidizing the customers who take service at lower voltages.

5. The TODP rate should contain a separate provision to address the setting of a ratchet demand for customers with on-site or distributed generation. When there is a LG&E system fault that interrupts power to customers, who have significant on-site or distributed generation, a demand should not be established for 60 minutes after service is fully restored.

6. LG&E's proposed Substitute Gas Sales Service rate would contain a ratchet provision that will be applied to the previous 11-month highest day demand to establish the minimum billing demand.

7. Since the Substitute Gas Sales Service rate is a new rate, the maximum daily demand that Fort Knox incurred in the previous 12-month period should be ratcheted or reduced by 50% for purposes of establishing the minimum billing demand going forward.

<u>III. ELECTRIC COST OF SERVICE STUDIES</u>

Q DID LG&E PREPARE AN ELECTRIC COST OF SERVICE STUDY?

A Yes. LG&E, prepared two versions of the cost of service study using alternative methodologies to allocate fixed production cost. The first version of the cost of service study, the modified Base-Intermediate-Peak ("BIP") methodology, has been used in prior LG&E rate cases as a means of allocating costs to rate classes. A second version of a cost of service study, is LOLP methodology. Both of these methodologies are discussed in the direct testimony of LG&E witness William Steven Seelye of The Prime Group, LLC.

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

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

Q DO YOU SUPPORT THAT PREMISE?

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

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

Q WHAT ARE THE MAJOR STEPS IN A COSS?

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

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

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

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

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

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

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

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

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

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

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

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

Q PLEASE COMMENT ON LG&E'S BIP COSS.

A Under this COSS methodology, production and transmission demand related costs were assigned to three categories – base, intermediate and peak. These three categories of demand related costs are allocated to the various rate classes using different allocation factors.

Q UNDER THE BIP METHODOLOGY, ARE ALL DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS ALLOCATED BASED ON DEMANDS?

A No. Under the BIP methodology, the base load costs are allocated to the various rate classes based on average demand or energy. However, the intermediate and peak demand related or fixed production and transmission costs are allocated using the winter and summer demands, respectively. As a result, approximately 35% of the production and transmission fixed costs are allocated to the various rate classes based on energy rather than peak demands.

Q DO YOU SUPPORT THE USE OF THE BIP METHOD FOR ALLOCATING FIXED AND/OR DEMAND RELATED PRODUCTION AND TRANSMISSION COSTS?

A No. Generally, those who endorse the methodology similar to the BIP argue that it reflects resources planning because it accounts for both coincident peak and average demand. Typically, the reasons for using this type of method is because this method assumes that the electric utility will invest in more expensive types of generation capacity solely because of more fuel cost associated with that capacity. As a result, this assumes a substitution of capital investment for fuel costs.

Q WHAT ARE THE FLAWS WITH THE BIP METHOD?

A The basic flaws with utilizing the BIP method are:

1. Energy consumption or average demand is double counted in the allocation process.

2. The BIP method, which is used as capital substitution, fails to approximately recognize the tradeoffs between capital and operating costs. This is sometimes referred to as fuel symmetry problem.

3. The BIP method is an over-simplification of the utility planning process.

Q WHY DO YOU SAY THAT THE BIP METHOD DOUBLE COUNTS AVERAGE DEMAND OR ENERGY?

A Double counting occurs because the average demand, which is equivalent to the year-round energy consumption divided by 8,760 hours, is also a component of the coincident peak demand. By allocating some capital costs relative to average demand, and some relative to coincident peak demand, energy is counted twice − once by itself and the second time as a subset of the coincident peak. If the year-round energy is analogous to base load units, which supply capacity on a continuing basis throughout the year, then it follows that the only time when intermediate and peaking units would be needed to meet the system demands are when they are in excess of the average year demand. The BIP method improperly allocates the cost of this additional capacity relative to the total coincident demand, rather than the excess demand.

Q TURNING TO YOUR SECOND CRITICISM, HOW DOES THE BIP METHOD, AS A CAPITAL SUBSTITUTION METHOD, FAIL TO PROVIDE A SYMMETRICAL ALLOCATION OF BOTH CAPITAL AND OPERATING COSTS?

A The BIP method focuses on the allocation of fixed production and transmission costs. For example, the BIP method allocates more production and transmission plant to high load factor classes than the peak demand method. Allocating fixed production costs on average demand or energy is claimed to be fair by proponents of these allocation methodologies because high load factor customers require more base load capacity and because the capital cost of base load units tends to be higher than peaking plants. However, the BIP method, as applied, makes no attempt to recognize the other side of the capital cost/operating cost trade-off. To ignore the fuel cost differential creates a mismatch between the theory and application

Q IS THE BIP METHOD APPROPRIATE FOR ALLOCATING PRODUCTION AND TRANSMISSION COSTS?

A No. It is inappropriate for allocating fixed production and transmission cost for the reasons I have previously stated.

Q HOW ARE COSTS ALLOCATED IN THE LOLP COST OF SERVICE STUDIES?

A The LOLP represents the probability that LG&E's system demand will exceed its generation during any given hour. LG&E calculates a LOLP for each hour. The

LOLP takes into account the magnitude of the hourly load, installed generation capacity, forced outage rates, maintenance schedules and other generating operating statistics. The LOLP is a critical measurement used by LG&E and KU in planning its generation resources. Therefore, the LOLP can serve as a method for allocating fixed generation and transmission costs to customer rate classes. In other words, allocating fixed production and transmission costs on the basis of the LOLP links the cost of service allocation methodology to the measurements used by LG&E and KU to plan the system.[1]

LG&E witness Mr. Seelye discussed the LOLP methodology in detail in his prefiled direct testimony.

Q DO YOU BELIEVE IT IS MORE APPROPRIATE TO USE THE LOLP METHODOLOGY THAN THE BIP METHODOLOGY FOR ALLOCATING FIXED PRODUCTION AND TRANSMISSION COSTS TO THE VARIOUS RATE CLASSES?

A Yes. The costs that are allocated using the LOLP allocator are fixed production costs and do not vary with energy consumption. The LOLP methodology does not allocate any fixed costs on energy while the BIP methodology allocates base fixed production costs on energy.

[1]Direct Testimony of William Steven Seelye, pages 90-91.

Q UNDER THE LOLP METHOD, IS EACH HOURLY LOAD GIVEN SIMILAR LOSS OF LOAD PROBABILITIES?

A No. In fact, reviewing the development of the hourly LOLP allocators, it only takes approximately the top 50 peak hours when the loss of load probability is the greatest to develop the LOLP allocator. That is, after the 50 highest LOLP hours, the loss of load probability is so small it does not significantly contribute to the development of the allocator. As a result, the LOLP methodology gives much greater weight to the peak hours.

Q WHAT IS YOUR RECOMMENDATION REGARDING WHICH COST OF SERVICE STUDY SHOULD BE UTILIZED TO ALLOCATE ANY REVENUE INCREASE IN THIS CASE?

A I would recommend that the Commission abandon the BIP method for the reasons stated above and utilize the LOLP method for purposes of determining the allocation of fixed costs. I would like to state that I specifically would endorse the use of a peak allocator for the summer months, but am not proposing that in this case.

IV. TIME-OF-DAY PRIMARY SERVICE ("TODP")

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

A Yes. First, the TODP, the proposed rate design reduces the base demand charge while increasing the intermediate and peak demand charges. This is more reflective of the LOLP cost of service study, and consistent with the price signals that the time-of-day rate should send. Also recovering any of the fixed production and transmission cost through the energy rate would produce intra-class rate subsidies.

Second, the TODP rate should reflect a voltage discount for customers who take service at 34.5 kV. Third, for those customers that have on-site generation of at least 1 MW, the TODP rate should include a demand waiver provision when a LG&E system fault occurs that interrupts power to the customer. A billing demand should be established 60 minutes after power is restored by LG&E, and not 15 minutes as stated in the TODP tariff. When an interruption occurs, a customer's on-site or distributed generation will trip for safety reasons, as to avoid back feeding the LG&E system, and/or because the generation is unable to supply all the installation's load. Once the LG&E power is restored, the customer should be given a 60-minute window, not 15 minutes, to safely bring back on line its on-site generation. After the 60 minute period, the customer will establish a billing demand that may be used to develop ratcheted demand for the next 11 months.

Q WHY DO YOU BELIEVE A DISCOUNT FOR CUSTOMERS TAKING SERVICE ON THE TODP RATE AT 34.5 KV IS REQUIRED?

A The cost of service study combines all of the distribution costs for the TODP customers in the base demand charge and does not distinguish by service voltage. The TODP distribution costs include cost for customers that are served at 2,400/4,160 volts, 7,200/12,470 volts and 34,500 volts. In response to a Data Request Question 10 by DoD/FEA, LG&E responded that less than 1% of the TODP customers take service at 34.5 kV. There are 107 customers currently taking service at this rate so the response indicates that there is probably only one customer currently taking service at 34.5 kV. (Exhibit DSS-1)

By requiring the 34.5 kV customers to support the lower voltage distribution cost results in creating subsidies within that rate class. Therefore, a discount should be afforded for customers that take service at 34.5 kV.

Q DOES NOT HAVING A DISCOUNT FOR CUSTOMERS TAKING SERVICE AT 34.5 KV CREATE AN INTRA-CLASS RATE SUBSIDY?

A Yes. In fact, LG&E believes that intra-class subsidies should be avoided. In response to the Sierra Club's Initial Data Request, Question No. 17 a., LG&E witness Seelye stated the following:

> "The Company believes that it is good business practice to avoid intra-class subsidies. Individual customers should not be subsidized by other customers.
>
> The rationale for eliminating intra-class subsidies is the same as for eliminating inter-class subsidies. Section 278.030(1) of the Kentucky Revised Statutes requires regulated utilities to charge fair, just, and reasonable rates for all ratepayers. Inter-class subsidies are readily determined from a cost of service study through the calculation of class rates of return. The rate of return calculation demonstrates whether a class's revenue is sufficient to cover the cost of providing service, including financing costs. In theory, each class' rate of return would be the same with perfectly fair, just, and reasonable rates. It is common in the utility industry to reduce subsidies with each rate increase and move each class rate of return toward an equalized rate of return. Classes with rates of return above the overall company rate of return are said to be paying a subsidy, while classes with rates of return below the overall rate of return are said to be receiving a subsidy.
>
> Intra-class subsidies are no different. They are simply subsidies that occur between customers in a class rather than between different classes. Accepting the principle that it is important to correct subsidies between classes in order to have fair, just, and reasonable rates, it

> necessarily follows that it is also important to correct intra-class subsidies.
>
> Intra-class subsidies cannot be readily determined from a class cost of service study. However, the rate factors that cause intra-class subsidies are well understood. Intra-class subsidies are caused when the rate components fail to match the cost-based components derived from a cost of service study. It is typically caused by recovering fixed costs through variable rate components. This creates a situation where a portion of the fixed costs are collected from the wrong customers. For example, if the basic service charge is too low, and those costs are recovered through the energy/commodity charge, then customers who purchase more than the average amount of energy/commodity will pay more than their fair share of those fixed costs. Customers that purchased less than the average amount of energy/commodity will pay less than their fair share of those fixed customer costs. This creates a subsidy where high use customers subsidize low use customers. The actual rate design compared to a cost based rate design determines the direction of the subsidy within each class of service."

The same logic applies to the recovery of distribution costs. Since the 34.5 kV customers do not utilize the lower voltage distribution system their rates should be adjusted accordingly.

Q WHAT IS YOUR RECOMMENDATION?

A My recommendation is to reduce the Basic Demand Period charge for any customer taking service at 34.5 kV by 25%.

Q HOW DID YOU DEVELOP THE 25% DISCOUNT?

A The 25% discount was developed by reviewing the transmission and distribution plant cost allocated to Rate TODP. The result of this analysis is shown on Exhibit JTS-1.

The analysis shown on Exhibit JTS-1 developed a transmission and distribution revenue requirement that reflects a return on and of the investment allocated to the

TODP rate plus the operating and maintenance expense. This analysis indicates that 52% of the bases demand charge, which only recovers transmission and distribution costs, is distribution cost related. Applying this ratio to the base demand charge of $3.18/kVA indicates that the distribution component of the distribution charge is $1.65/kVA ($3.17/kVA x 52%). Because only one customer takes service at 34.5 kV, it is reasonable to assume that less than 50% of the distribution cost included in the cost of service is related to voltages lower than 34.5 kV. Just so it is clear, customers taking service at 34.5 kV do not use or rely on the lower voltage distribution system included in the TODP rates. Reducing the distribution component of the basic demand charge by 50% produces a credit for 34.5 kV customers of $0.825/ kVA. I am proposing that the TODP tariff reflect a 25% reduction in the Basic Demand Period charge.

Q WHAT IS YOUR SUPPORT FOR YOUR CONTENTION THAT THE BASE DEMAND CHARGE ONLY CONTAINS TRANSMISSION AND DISTRIBUTION RELATED COST?

A In response to DoD/FEA Data Request No. 5, LG&E responded the following:

> "The base demand charge is designed to recover 100% of transmission and distribution demand related costs as determined by the class cost of service study."

It is clear from this response that the base demand charge is designed to recover only transmission and distribution costs.

Q YOU ARE ALSO PROPOSING A CHANGE IN THE DETERMINATION OF THE BILLING DEMAND FOR CUSTOMERS THAT HAVE SIGNIFICANT ON BASE GENERATION. IS THAT CORRECT?

A Yes. When a customer, who takes service from LG&E and has substantial on-site generation, is interrupted because of a system fault on LG&E's system, the customer's on-site generation will shut down. The on-site generation is shut down for several reasons. The first being for safety reasons. If the generation continues to run, it will back flow power to LG&E's system. This could produce a hazardous condition for LG&E employees. Second, even if the generation could be isolated from LG&E's system, it may not be capable of supplying the entire total load requirements of the installation. This condition would require a shut down. Finally it is necessary to synchronize the on-site generation with LG&E's system to avoid equipment damage. As a result, the on-site generation has to be shut down and restarted once LG&E's power is restored.

When there is a LG&E interruption, the on-site generation is not brought back on line until service is restored by LG&E. Under the current TODP rate provisions, a billing demand is set based on a 15-minute period. If the customer cannot bring its generation on within this 15-minute window, the customer could set a new billing demand based on an event that was out of its control. If this billing demand sets a new high, it would also be used to establish a new ratchet demand. This ratchet demand could set a minimum demand for billing purposes for the next 11 months. This could result in the customer paying demand charges that are a result of an incident that is out of its control.

It should be noted that customers may operate some of its on-site generation during the peak periods. If the interruption and restoration occurs during the peak period, the customer may face additional costs simply because the generation cannot be brought back on line safely in 15 minutes.

Q WHAT IS YOUR RECOMMENDATION TO CORRECT FOR THIS SITUATION?

A I am proposing that when this occurs a new billing demand should not be established for 60 minutes. That is, after service has been restored the customer has 60 minutes to bring back its generation. The demand that occurs in the 15-minute block after the 60 minute interval would be utilized to determine the billing demand and possibly the ratchet demand for the next 11 months. Of course, if this is not the highest demand in the previous 11 months, it will not be used as the minimum ratcheted billing demand.

Q WHAT ARE THE RATCHET PROVISIONS IN THE PROPOSED TODP RATE?

A For the peak and intermediate demand periods, the demand charge is based on the maximum demand measured in the current billing period, or a minimum of 50% of the highest measured load in the preceding 11 monthly billing period. For the base demand period, the billing demand is the maximum demand measured in the current billing period, or the highest load in the preceding 11 monthly billing period. Therefore, setting an artificially high demand based on an event that is out of the control of the customer should not be used to establish future billings.

Q HAVE YOU DEVELOPED TARIFF LANGUAGE FOR THE IMPLEMENTATION OF THE TWO PROVISIONS OR REVISIONS THAT YOU ARE PROPOSING FOR THE TODP RATE?

A Yes. To address the discount for customers taking service on the TODP rate at 34,500 volts, a clause should be added at the end of the "Rate" section of the TODP tariff that states the following:

> "For customers taking service at 34,500 volts, the Base Demand Period charge should be reduced by 25%."

To address the issue of setting a billing demand after a LG&E fault for a customer with on-site generation, the following should be added to the "Determination of Maximum Load" section of Rate TODP:

> "If a customer has at least 1,000 kW of on-site distributed generation other than solar, and the customer's power is interrupted by LG&E, the customer's billing demand will not be established for 60 minutes. The first 15 minute period after the 60 minute waiting period will be used to establish a billing demand for that month."

The two clauses above should be added to the TODP tariff.

V. SUBSTITUTE GAS SALES SERVICE ("SGSS")

Q IS LG&E PROPOSING A NEW GAS RATE FOR THE SERVICE THAT FORT KNOX CURRENTLY TAKES?

A Yes. LG&E is proposing Rate SGSS. This rate is proposed to provide gas service for any customer who desires to meet firm sales service from LG&E in addition to gas received from other sources to which the customer is physically connected.[2] This rate would apply to customers who normally purchase gas directly from a pipeline from

[2] Direct Testimony of William Steven Seelye at page 62.

another local distribution company or from a local producer but relies on LG&E for an alternative substitute supplier of natural gas. LG&E contends that this rate is necessary because it would be required to maintain sufficient storage and distribution delivery capacity on its system to provide firm service to a customer under Rate SGSS just as it would for any other commercial or industrial customer that receives firm sales service from LG&E under another rate. LG&E witness Mr. Seelye discusses the rate in greater details on pages 67 through 76 of his direct testimony.

Q DO YOU PROPOSE ANY REVISIONS TO THE PROPOSED RATE SGSS?

A Yes. The proposed tariff states the following regarding the monthly billing demand:

> "The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered during the current month or the previous 11 monthly billing periods. The term Day or Daily when the time period of correspondence to the gas day as observed by the pipeline transporter as adjusted for local time."

Consistent with the establishment of billing demands for the electric tariffs, such as the TODP rate, I am proposing that a ratchet provision be established to determine the billing demand incurred during the previous 11 months. I am proposing that a ratchet provision of 50% be applied to the highest daily volume of gas delivered during the previous 11 monthly billing periods. A 100% ratchet is punitive and does not reflect any type of usage diversity by LG&E's customers.

As a result, the customer in any given month will pay a demand charge based on the higher of the highest daily volume of gas delivered during the current month, or 50% of the daily volume demand created in the previous 11 monthly billing periods. It should be noted that under LG&E's gas rate proposal in this case, the movement from Fort Knox's current gas rate to the proposed Rate SGSS, would increase Fort Knox's gas bill by over 200%.

Q WITH THE IMPLEMENTATION OF RATE SGSS, HOW SHOULD THE INITIAL BILLING DEMAND BE ESTABLISHED?

A With the implementation of Rate SGSS, I am proposing that the minimum billing demand be applied to the highest billing demand that has occurred in the previous 11 months and that that billing demand is applied to my proposed 50% ratchet provision.

If the Commission rejects the proposed ratchet provision, the initial minimum demand should be based on the average of the ten highest daily billing demands that occurred during the previous 11 months.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

VI. QUALIFICATIONS OF JAMES T. SELECKY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

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

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

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

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

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

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

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

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

\\Doc\Shares\ProlawDocs\TSK\10359\Testimony-BAI\315049.docx

Exhibit JTS-1

Development of 34.5 kV Discount for Time-of-Day Primary Service

Witness: James T. Selecky

Louisville Gas and Electric Compnay

Development of 34.5 kV Discount for Time-of-Day Primary Service

Line	Description	Transmission Rev Req	Distribution Rev Req	Total Rev Req
1	Rate Base	$ 30,228,916	$ 30,248,486	$ 60,477,402
3	Pre-Tax ROR	10.733%	10.733%	10.733%
3	ROR & Inc Tax	$ 3,244,498	$ 3,246,599	$ 6,491,097
4	O&M Exp.	$ 2,658,239	$ 2,910,065	$ 5,568,304
5	Dep Exp	$ 1,412,512	$ 1,748,827	$ 3,161,339
6	Rev Req	$ 7,315,249	$ 7,905,491	$ 15,220,741
7	Percent	48.06%	51.94%	
8	Base Demand ($/kVA)	$ 1.53	$ 1.65	$ 3.18
9	50% 34.5kV Adj		$ 0.826	
10	Reduction in Total Base Demand Charge		26%	