COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00371**

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2017

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background and experience.

A. I graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

I have more than forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court.

A complete copy of my resume and my testimony appearances is contained in Baron Exhibit__(SJB-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers ("KIUC"), a group of large industrial customers taking service on the LG&E and KU systems. The KIUC members who take service from the Companies are: AAK, USA K2 LLC, Air Liquide Industrial U.S. LP, Alliance Coal LLC, Carbide Industries LLC, Cemex, Corning Incorporated, Clopay Plastic Products Co. Inc., Dow Corning Corporation, Ford Motor Company, Ingevity, Lexmark International Inc., North American Stainless, The Chemours Company and Toyota Motor Manufacturing, Kentucky, Inc.

Q. Have you previously testified in KU and LG&E rate proceedings before the Kentucky Public Service Commission?

A. Yes. I have testified in 15 KU and LG&E cases since 1981, a period of 36 years.

Q. How have you organized your testimony with regard to LG&E and KU issues?

A. For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic principles associated with cost allocation and rate design. However, since the revenue requirement requests and the specific cost of service study results for LG&E and KU rate classes are different, I will be presenting separate analyses and discussions of these results.

For the purposes of organizing my testimony, when I am discussing an issue that is common to both LG&E and KU, I will refer to these companies as ("the Company" or the "Companies"). For a specific LG&E and KU issues I will refer to each Company by name (LG&E or KU).

Q. What is the purpose of your testimony?

A. I am presenting testimony on a variety of cost of service and rate design issues. The first issue that I address concerns the Company's filed cost of service studies using the base-intermediate-peak ("BIP") class cost of service methodology and the newly proposed Loss of Load Probability ("LOLP") method. I have identified significant and material problems with the Companies' projected test year (12 Months ended June 30, 2018) hourly load data that is used to develop the key demand allocation factors in both cost of service studies, for both utilities. These problems lead me to conclude that neither of the Companies' class cost of service studies are producing reliable results. As such, these studies cannot be used a reasonable guide to allocate the overall revenue increase to rate classes.

I also address the specific cost of service study methodologies filed by the Companies in this case. Putting aside the erroneous demand allocation factors, as I have testified in prior LG&E and KU cases, I do not believe that the BIP methodology is the most reasonable approach to class cost of service analysis. The BIP method tends to allocate an inappropriately large percentage of the Companies' production costs to high load factor industrial rate classes because a significant portion of these production costs are classified as energy related (the base portion of the BIP method). In addition, the Companies' modified BIP method is not consistent with the BIP method that is discussed in the NARUC Electric Utility Cost Allocation Manual ("the NARUC Manual"), which is a standard treatise on electric utility cost allocation methodologies. I will also address the new proposal in this case to allocate production demand costs on the basis of hourly probability each hour that there is insufficient capacity available to meet load in that hour. This new proposal is a radical departure from traditional cost allocation methods that imposes a greater share of the system's fixed production capacity on high load factor classes that serve industrial customers. I will explain why the Commission should reject this new methodology proposal. While I believe that alternative cost allocation methodologies should be considered by the Commission, such as a summer/winter coincident peak method, because of the erroneous hourly load data produced by the

Companies, there is no basis to actually develop such studies in this case. Because the Companies' studies cannot be relied on due to the load data problems, I will recommend an alternative apportionment of the overall revenue increase to rate classes based on a uniform percentage increase to each rate class.

I will also address the Companies' proposed revisions in rate design for its large, demand-metered rate classes. Specifically, the Companies are proposing to implement a 100% demand ratchet for the base demand charges of these rates. As I will discuss, since these charges are associated with distribution costs, I do not oppose the ratchet revision.

Finally, I will discuss the Companies' proposal to recover costs associated with its requests for a full deployment of advanced metering systems ("AMS"). As discussed by KIUC witness Lane Kollen, KIUC opposes the inclusion of AMS costs on a projected test year basis. In the event that the Commission adopts the Companies' request to fully deploy an AMS plan, I discuss an alternative rate recovery approach through a per customer (per meter) rider that would permit recovery of costs that are actually expended, rather than on a projected basis as proposed by the Companies.

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **Both the BIP and LOLP cost of service studies presented by the Companies in this case rely on erroneous hourly load data to develop rate class demand allocation factors that produce unreliable and unusable cost study results. Because of these significant and material errors, the Commission should not rely on either of these studies in this case.**

- **Because of the cost of service errors that make the filed cost study results unreliable, the Commission should apportion the overall approved revenue increases for each Company on a uniform percentage basis to each rate class.**

- **The Commission should accept the Companies' proposed increase to the demand ratchet for the base demand charges of Rates TOD-S, TOD-P, RTS and FLS. This proposal is reasonable and reflects cost causation.**

- **In the event that the Commission accepts the Companies' request for approval of a large scale AMS program, the costs should be recovered in a separate rider, rather than through base rates. This proposal will permit the Companies to adequately recover their costs, while protecting customers from paying forecasted charges that may not be incurred. By using a rider, only actual costs associated with AMS expenditures that are actually incurred (as opposed to projections) will be recoverable from customers. The AMS riders should recover the costs for these advanced meters from all customers on a uniform per customer (per meter) basis.**

II. CLASS COST OF SERVICE STUDIES

Q. What is the purpose and use of a class cost of service study in electric utility ratemaking?

A. As discussed in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual"), the purpose of a class cost of service study is to "aid in the design of rates."

Specifically, the NARUC Manual states that "Regulators design rates, the price charged to customer classes, using the costs incurred by each class as a major determinant."[1] While this is a relatively straightforward, logical statement, it is important to recognize that there are multiple methodologies that can be used to allocate costs to customer classes. The NARUC Manual itself identifies more than 10 methodologies, some of which include multiple variants.[2] The results of a class cost of service study can vary significantly, depending on the methodology used to determine rate class responsibility for each type of costs.

Q. Should the Commission consider alternative methods from those that the Companies have filed in this case?

A. Yes. The Companies have filed two very different class cost of service studies, which produce different results. These studies, the Base Intermediate Peak ("BIP") method and the Loss of Load Probability ("LOLP") method are only 2 of the more than 10 methods discussed in the NARUC Manual. The BIP method used by the Companies for many years is not really the BIP method discussed in the NARUC Manual, but a modified version of it. The LOLP study, which Mr. Seelye appears to place more weight on in this case, has never been used by either Company previously, nor has it been used by Mr. Seelye or other members of his firm [see response to KIUC 1-87 attached as Baron Exhibit__(SJB-2)]. In fact, the

[1] NARUC Electric Utility Cost Allocation Manual at page 13.

Companies are not aware of any utility that uses the LOLP methodology for ratemaking [see response to PSC 2-78 attached as Baron Exhibit__(SJB-3)].

As a general matter, I believe that it is important for the Commission to consider alternative class cost of service methodologies. Ordinarily, as I have done in prior LG&E and KU rate cases, I would present alternative class cost of service studies for each of the Companies. However, because of the significant load data problems that I have identified, any such alternative studies would suffer from the same erroneous demand allocation factors that have been used in the Companies' cost of service studies. I therefore have am not providing alternative cost studies in this case.

Q. Are cost of service results the only factors to consider in allocating the approved overall revenue increase to rate classes?

A. No. As the NARUC Manual discusses, the main purpose of a class cost of service study is its use in the development of rate class rates. In most regulatory jurisdictions, cost of service results are one input into the ratemaking process. Other factors include gradualism, avoidance of rate shocks, competiveness issues and the impact on economic development, as well as other factors that regulators may rely

[2] Among these are: 1 coincident peak (CP), summer/winter CP, 12 CP, multiple CPs, Average and Excess, Equivalent Peaker, Base and Peak, Peak and Average, LOLP, Probability of Dispatch and BIP.

on in a particular state. I will discuss these issues in Section III of my testimony where I address the allocation of the overall revenue increase to rate classes.

Q. What are the main differences between the two class cost of service studies presented by the Companies in this case?

A. These two studies allocate production demand related costs differently, based on two alternative measures of cost causation. Production demand costs are the fixed costs associated with a rate of return on the Companies generating unit investment, depreciation of these investments, operation and maintenance expenses, property and income taxes, as well as other related costs directly associated with the investment in generation resources. The cost of service studies allocate these fixed, demand related costs to individual rate classes on the basis of various demand allocation factors that are calculated for the projected test year using hourly loads for each rate class. In addition, these same hourly loads are used to allocate transmission and distribution costs to each rate class.

Q. Are these hourly loads the primary factor in determining the dollar amount of costs that are assigned to each rate class?

A. Yes. The test year hourly loads (8,760) are the basis for all of the demand allocation factors used to allocate costs in both the BIP and LOLP cost studies – these allocation factors thus determine the results of the cost allocation study. If the loads estimated for each rate class are not correct, the studies themselves cannot be relied on and are essentially erroneous.

Q. Have you identified any problems with the Companies' projected hourly load data that is used to calculate the demand allocation factors in the BIP and LOLP class cost of service studies?

A. Yes. There is a significant problem with the Companies' projected hourly demands. As such, the demand allocation factors that are derived from this data are incorrect. This means that the cost of service results are also incorrect, regardless of the demand allocation method used, because each study uses the hourly data that are erroneous.

Q. Would you explain why you believe that the Companies' hourly load data is erroneous?

A. The starting point for the development of the Companies' projected test year hourly load data for each rate class is actual hourly load data for the 12 months ending June 30, 2016. For most rate classes, the actual data are based on load research sample data for this 12 month period, adjusted to match the actual billed energy that is a known factor. For KU's FLS rate class, however, KU has hourly (actually, 5 minute) loads for the entire 12 month period ending June 30, 2016. As is the case for each rate class (KU, LG&E), the historic hourly loads are slightly adjusted so that the energy (sum of the hourly loads) matches the actual energy sales for the class for the same 12 month period. I will refer to these hourly loads as the "actual" hourly load data for the period ending June 30, 2016.

Q. What do the Companies do next, to develop hourly loads by rate class for the projected test year, 12 months ending June 30, 2018?

A. Based on my review of the workpapers supplied by the Companies (response to AG 1-274, PSC 2-97), the actual 12 month ending June 30, 2016 data ("actual data") is adjusted multiple times, ostensibly to:

1. Match the 2018 test year energy forecasted for each rate class
2. Match the 2018 test year hourly load data for the system that is referred to in the Companies' workpapers as "EMS" data.

This process is briefly summarized in the Companies' response to AG 1-274 (KU version) attached as Baron Exhibit__(SJB-4).

Q. Is the Companies' description of the process in its response to AG 1-274 entire accurate?

A. No. I have summarized the actual process used by the Companies in Baron Exhibit__(SJB-5). As I explain in this exhibit, the actual hourly load analysis developed by the Companies involves numerous adjustments to a set of actual hourly load data for the period 12 months ending June 30, 2016. These adjustments include a daily re-ordering of the projected class hourly load data that was intended to match the Companies' Energy Management System ("EMS") hourly load projection. The EMS hourly load projection is a separate forecast of system hourly loads for the test year (12 months ending June 30, 2018) that is used for generation planning. However, as I discuss in Exhibit__(SJB-5), the Companies made an error in this re-ordering that has led to significant errors in the test year class hourly loads. These loads are directly used to develop the class cost of service study demand allocation factors in both of the Companies' cost studies (BIP, LOLP). As such, as I will discuss, these studies cannot be relied on in this case.

Q. Would you briefly explain the re-ordering error?

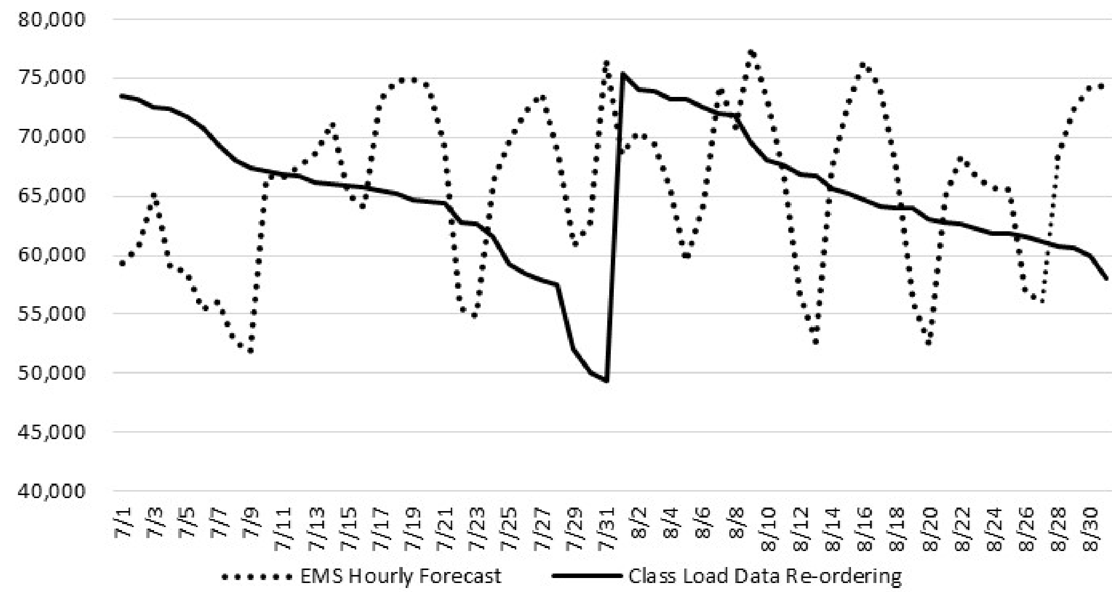
A. Yes. As discussed in detail in Exhibit__(SJB-5), the re-ordering error occurs in one of the final steps in the Companies' calculation of test year rate class hourly loads. The Companies intended to re-order the projected class load data to match the same daily shape as it projected for the EMS data. This was done by assigning a rank to the daily EMS data (1 to 31 for the month of August) and finding the corresponding day's rank for the class load data. For example, if the highest day in the EMS data for August 2017 was August 14th (a rank of 1), then the Companies intended to re-order the class loads so that the highest day's data for class loads August fell on August 14th. Let's say that the highest day for the class loads was August 23rd – this days' data for all the hourly class loads should have been reset to August 14th, the day of highest loads in the EMS data. What the Companies actually did was use the rank value (in this case "1") as the date. In this example, the class load data for August 23rd was reset to August 1st, not the intended August 14th. Baron Exhibit__(SJB-6) illustrates the error in the ranking using the Companies' data for the month of August 2017.

Q. Does the re-ordering error result in the highest daily loads to always be the first day of each month?

A. Yes. The ranking analysis re-orders all of the class load data so that the highest loads are on day one of each month (for example, July 1 or August 1) and the lowest daily loads are on the last day of the month. <u>This clearly illustrates that the Companies' projected load data is incorrect because it is simply not the case that the highest loads on the system always occur on the 1st of each month and the lowest loads occur on the last day of the month.</u>

Figure 1, below, shows the re-ordered data for the projected test year months of July 2017 and August 2017. Also shown on the graph is the system EMS data that the Companies intended to match. As can be seen, the daily load patterns created by the ranking step are totally out of sync with the true load pattern. In the final step of the Companies forecast, this re-ordered data is then scaled to the EMS hourly load data. Because of the incorrect re-ordering, the scaling factors create a final set of data that produces incorrect results.

Figure 1
KU Daily Load Ranking



Q. Is the re-ordering error the only cause of the load data problems that you have identified?

A. No. This error is simply one cause of the problems. Correcting the re-ordering error alone would not fix the problems with the Companies' projected demand allocation factors. The entire methodology of adjusting actual historical data multiple times based on monthly energy forecasts and matching to EMS load shapes (even if with a correction to the re-ordering step) is likely to have caused erroneous results on a class basis. This is especially the case for KU's FLS rate class that has a single customer. <u>In the case of KU's FLS rate, which I discuss in more detail next, the load data problems are clearly related to multiple aspects of</u>

the Company's methodology. Since the class loads are critical inputs into the cost of service study, the resulting cost allocations are not reliable.

Q. Can you illustrate the magnitude of these load data errors that you have identified in the Companies' analysis?

A. Yes. I examined the forecast results for KU's FLS rate class and compared these data to the actual data. The advantage of focusing on KU's FLS rate is that there is only one customer on this rate schedule. Table 1 below summarizes two key data metrics for FLS, comparing results for the test year to the actual, known data for the 12 months ending June 30, 2016. These comparisons, by month are shown for 1) monthly energy and 2) monthly maximum hourly demand.

Table 1
KENTUCKY UTILITIES COMPANY
Impact of Company Forecast Adjustment Methodology - Rate FLS

	Sum of Hourly Loads			Maximum Hourly Peak		
	Historic 2015-2016	Forecast 2017-2018	% Change	Historic 2015-2016	Forecast 2017-2018	% Change
July	44,937,303	46,202,495	2.8%	114,934	148,856	29.5%
August	40,707,621	44,966,330	10.5%	120,784	160,706	33.1%
September	43,148,436	47,304,914	9.6%	122,253	146,639	19.9%
October	45,642,798	47,218,366	3.5%	122,729	139,479	13.6%
November	41,221,057	45,988,054	11.6%	147,700	196,844	33.3%
December	39,660,485	42,092,825	6.1%	122,384	162,809	33.0%
January	47,470,382	48,575,080	2.3%	123,903	163,791	32.2%
February *	43,972,541	45,802,725	4.2%	127,202	199,555	56.9%
March	42,990,565	46,685,885	8.6%	132,557	161,496	21.8%
April	49,767,119	48,385,994	-2.8%	121,797	140,363	15.2%
May	49,757,160	48,772,596	-2.0%	123,765	157,596	27.3%
June	47,984,236	46,556,179	-3.0%	115,410	141,603	22.7%
Total	537,259,703	558,551,443	4.0%			

* Historic period excludes February 29, 2016

As can be seen, there are some stark, inexplicable differences in the maximum monthly demands between the 2018 forecast and the actual 2016 data. <u>These demands cannot be explained by forecasted growth for the FLS customer because that is relatively small based on the growth in energy usage.</u> For example, in February 2018, the FLS maximum hourly demand is shown in the Companies' analysis to be 199,555 kW, compared to the actual February 2016 maximum demand of 127,202 kW. This is an increase in load of 56.9% and compares to the forecasted increase in energy use for February of 4.2%. This is obviously in error and significantly overstates the FLS demand. Similar erroneous results are shown for the other 11 months of the test year.

Q. Could the 19.9% to 56.9% increase in hourly demands assumed by the Companies be justified on the basis that the FLS load shape changed?

A. Absolutely not. First, there is simply no evidence that the FLS load shape will change. The hourly FLS loads are based on the operation of the North American Stainless ("NAS") facility, and this is not changing. Moreover, there is absolutely nothing in the LG&E/KU analysis that considers any change in FLS (or any other rate classes' load shape). This is confirmed in the description of the methodology provided in response to AG 1-274. All of the adjustments that are made to the actual 2016 hourly load data to convert them to 2018 test year data are applied to all customer classes. In other words, the adjustments are uniformly made to each of the hourly loads of all rate classes – there is no information used in the analysis that would reflect a load shape change for any single rate class.

Q. Would this problem impact other hourly demands?

A Yes. All of the hourly demands are incorrect. This would include the summer and winter coincident peak demands used in the BIP cost study to allocate peak and intermediate period costs to rate classes. It would also include the LOLP allocation factors used by Mr. Seelye, since these are derived from the identical

2018 test year hourly load data used in the BIP cost of service analysis. Also, this would include the load data used to allocate transmission and distribution costs.

Q. Does this problem impact all rate classes, not just KU's FLS class?

A. Yes. First of all, it is important to recognize that most of the production demand, transmission demand and distribution demand allocation factors are calculated from this hourly load data. This means that a significant amount of the costs being allocated to rate classes are determined by this hourly load data. Second, even if the problems that I have identified with the FLS hourly load data only impacted FLS and not the other rate classes, because a cost of service study fully allocates 100% of the Company's jurisdictional costs, an over-allocation of costs to FLS (because of the overstated hourly loads) means that the costs for other rate classes are understated and that the entire class cost of service study is incorrect. However, I have concluded that the problems that I have identified are a direct result of a methodological error that impacts all hourly loads in the test year, not just for FLS. Table 2, below, illustrates this problem for each of KU's rate classes. It shows a comparison of the actual 2016 class maximum demand data and the projected 2018 class maximum demand data developed by the Company. Also shown is the forecasted increase in annual energy usage for each rate class for the same period (2016 vs. 2018). I have highlighted a number of large commercial/industrial classes to illustrate the disparities in the Company's calculations. As in the case of Rate FLS, other rate classes shows significant disparities in between the energy forecasts and the hourly load forecasts. For example, Rate RTS is projected to have a 2.2% increase in energy use, yet the Company projects that the RTS maximum demand will increase by 19.7%. Recall that the Company's methodology uses the 2016 hourly loads, with adjustments to reflect the energy forecast for the class (2.2% in this case) and various other energy related adjustments made to tie the combined rate class energy to the system energy use on a daily and monthly basis. There is no adjustment made to any rate classes' hourly load pattern that could justify the disparities in energy use and loads that the Company's has calculated. Another example is TOD Primary where in the future test year energy use is projected to decrease by 0.6%, but the maximum hourly demand is projected to increase by 20.4%.

Table 2
KENTUCKY UTILITIES COMPANY
Impact of Company Forecast Adjustment Methodology

	Sum of Hourly Loads			Maximum Hourly Peak		
	Historic 2015-2016	Forecast 2017-2018	% Change	Historic 2015-2016	Forecast 2017-2018	% Change
Residential	5,763,931,901	6,050,422,654	5.0%	1,876,122	1,958,980	4.4%
General Service	1,743,388,837	1,803,617,944	3.5%	451,903	496,748	9.9%
All Electric Schools	139,736,794	150,689,224	7.8%	42,130	47,739	13.3%
TOD Secondary	1,665,856,076	1,675,697,684	0.6%	297,635	342,637	15.1%
TOD Primary	4,164,291,471	4,137,639,203	-0.6%	675,566	813,494	20.4%
PS Secondary	2,011,483,286	2,153,660,404	7.1%	372,605	437,585	17.4%
PS Primary	150,212,885	170,681,556	13.6%	30,386	35,571	17.1%
RTS	1,468,948,183	1,501,685,508	2.2%	252,730	302,455	19.7%
FLS	537,259,703	558,551,443	4.0%	147,700	199,555	35.1%
Muni Primary	554,146,220	578,327,898	4.4%	112,569	117,733	4.6%
Muni Transmission	1,204,433,902	1,252,251,415	4.0%	231,554	245,859	6.2%
Comp 1	59,554,053	-				
Unmetered Lighting	122,535,013	123,634,478	0.9%	28,417	34,173	20.3%
Traffic Energy Service	1,523,371	1,489,131	-2.2%	174	221	27.3%
Lighting Energy Service	489,629	446,721	-8.8%	114	143	26.1%

Q. Do the same problems occur in the LG&E hourly loads used to develop demand allocation factors that are employed in its class cost of service studies?

A. Yes. The methodologies employed to develop the LG&E projected test year hourly loads are identical to the methods used for KU and there are similar erroneous results. Table 3, below, shows a comparison for LG&E between the 2016 and 2018 energy forecasts and the class maximum demands. As can be seen, there are significant disparities for a number of rate classes (RTS, Large

TOD, ITOD Secondary, for example). For example, in the future test year RTS energy usage is projected to increase by 4.3%, but the maximum hourly demand is projected to increase by 50.6%.

Table 3
LOUISVILLE GAS AND ELECTRIC COMPANY
Impact of Company Forecast Adjustment Methodology

	Sum of Hourly Loads			Maximum Hourly Peak		
	Historic 2015-2016	Forecast 2017-2018	% Change	Historic 2015-2016	Forecast 2017-2018	% Change
Residential	4,061,112,511	4,163,815,429	2.5%	1,300,274	1,420,688	9.3%
General Service	1,311,124,067	1,350,031,112	3.0%	348,984	407,670	16.8%
CPS Primary	150,315,919	152,001,520	1.1%	27,658	32,505	17.5%
CPS Secondary	1,682,079,746	1,634,881,254	-2.8%	330,949	360,602	9.0%
CTOD Primary	534,868,894	422,902,067	-20.9%	120,964	104,755	-13.4%
CTOD Secondary	802,531,798	799,392,315	-0.4%	138,803	167,894	21.0%
IPS Secondary	231,721,256	242,300,379	4.6%	49,925	63,463	27.1%
IPS Primary	10,271,148	13,981,478	36.1%	4,650	5,399	16.1%
ITOD Secondary	276,366,426	279,075,570	1.0%	46,756	61,158	30.8%
Large TOD	1,321,718,168	1,434,641,160	8.5%	223,706	295,681	32.2%
RTS	1,107,757,135	1,155,446,418	4.3%	169,782	255,713	50.6%
Comp 2	56,344,951	58,522,346	3.9%	10,328	12,791	23.8%
Comp 3	130,559,788	110,891,989	-15.1%	21,958	24,760	12.8%
Unmetered Lighting	103,084,459	101,763,757	-1.3%	23,840	26,916	12.9%
Traffic Energy Svc	3,099,411	3,108,713	0.3%	354	392	10.8%
Lighting Energy Svc	3,360,194	3,317,374	-1.3%	777	861	10.8%

Q. What do you conclude from your analysis of the Companies' load data and demand allocation factors?

A. Based on my review, the KU and LG&E hourly loads that are used to produce the demand allocation factors directly used in the Companies' class cost of service studies (both BIP and LOLP) are incorrect and therefore the cost of service results themselves cannot be relied on in this case.

Q. Have you reviewed the Companies' proposed "base-intermediate-peak" cost allocation study?

A. Yes. While I believe that the erroneous load data used in the Companies' cost of service studies makes the results of these studies invalid and unreliable, I have reviewed the BIP methodology independently.

The BIP method is the class cost allocation method used by LG&E in its prior cases for many years and has been used for by KU since 2003 (Case No. 2003-00434). It was first presented by LG&E in 1981 in Administrative Case No. 203(b), which investigated the cost of service standard included in the Public Utilities Regulatory Policies Act (PURPA).

The basic methodology, as discussed by Company witness Seelye, first functionalizes the Company's production demand-related costs into three periods. Under the Company's BIP functionalization that is used in both the LG&E and KU studies, total system production demand-related costs are assigned as follows:

- Base – 34.38%
- Intermediate – 36.02%
- Peak – 29.60%

These functional allocators for the base, intermediate and peak periods are identical for both LG&E and KU under the Companies' methodology. Once the total production demand-related costs have been functionalized to these three categories, they are allocated to rate classes using three different class allocation factors. For the 34.38% of production demand-related costs that are assigned to the base period, costs are allocated using class energy use. For the summer peak period costs that comprise 29.60% of all production demand-related costs, costs are allocated to classes based on class contributions to the summer system peak demand. Finally, for winter peak period costs that comprise 36.02% of the Company's total production demand-related costs under the BIP method, costs are assigned based on each customer classes' contribution to the winter coincident peak.

Q. Have these BIP percentages changed materially from the Companies' 2008, 2009 and 2012 base rate cases?

A. Yes. In the 2008 rate case, the "peak" period in the BIP method was the summer peak. This is consistent with the importance of the summer peak in driving generating capacity additions on the Companies' systems. In 2008, only 15.32% of the system production costs were assigned to the winter ("intermediate") period, with over 50% of costs assigned to the summer period. In the 2009 case, the "peak" period became the winter peak, with 43.3% of the system production demand costs allocated based on rate class winter demands. In the 2012 case, the BIP model assigned slightly more costs to the summer peak than to the winter peak (though the percentages were approximately equal). In this current 2016 case, the summer period is allocated the smallest share of costs, despite the fact that the combined Companies are strongly summer peaking during the projected test year (the summer peak is projected to be 11% higher than the winter peak). Table 1 below shows a comparison of the BIP percentage factors used to assign production demand costs to the base, intermediate and peak periods in the Companies' current and previous three rate cases.

Table 4
Comparison of BIP Classification Percentages

	2016	2012	2009	2008
Base	34.38%	34.35%	34.89%	33.89%
Intermediate (Winter)	36.02%	32.39%	43.25%	15.32%
Peak (Summer)	29.60%	33.26%	21.86%	50.78%

These dramatic changes in the BIP percentages over the past 8 years demonstrate that the BIP methodology produces questionable results that should not be the sole basis for cost allocation if rate continuity and consistency are considered important policy goals.

Q. Are there more fundamental problems with the Companies' modified BIP methodology?

A. Yes. The Companies' BIP methodology assigns production demand costs to each of three rating periods (base, intermediate, peak) using only mW loads in these three periods and does not reflect the actual operating costs of generation on the combined

LG&E/KU system. This is contrary to the description of the BIP methodology in the NARUC Manual. This BIP methodology is designed to recognize that base load plants have lower operating costs than intermediate and peaking plants. While I do not agree with the BIP methodological framework, it is clear that the Companies' modified BIP method does not consider these differences in operating costs that is the underlying rationale behind the BIP method. I have attached pages 60 through 62 of the NARUC Manual as Baron Exhibit__(SJB-7).

The Companies' modified BIP method assignment of production demand costs to the three rating periods is described in Mr. Seelye's exhibits WSS-16 (LG&E) and WSS-11 (KU).[3] As shown in Mr. Seelye's exhibit, the base period costs allocation is based on the simple ratio of minimum system load to maximum system summer demand – no assessment is made with regard to the Companies' generating unit operating costs, as discussed in the NARUC Manual. Costs are assigned to the Intermediate period based on a somewhat convoluted factor that is derived as follows:

1. Calculate the ratio of the winter peak demand to the summer peak demand and subtract the base period allocation percentage.

2. Multiply the result in Step 1 by the ratio of winter peak period hours divided by total summer peak period plus winter peak period hours.

[3] These two exhibits are identical since the same rating period allocation is used for each Company.

Again, there is no consideration of intermediate generating unit operating costs. The remaining costs are assigned to the summer peak period. Once again, there is no consideration at all given to peaking unit operating costs as discussed in the NARUC Manual.

Q. What are the implications of relying on the Companies' BIP cost studies?

A. As the BIP method shifts greater cost responsibility to the intermediate, winter peak from the summer peak, the results of the class cost of service study shifts. Given the significance of the Companies' summer peak, this tends to shift costs from the residential class to higher load factor large customer classes, particularly for LG&E.

Q. Has the Commission previously accepted the BIP methodology for use in LG&E and KU class cost service allocation studies?

A. Yes. However, the Commission has never, to my knowledge, accepted the Companies' BIP methodology proposed in this case that allocates transmission costs on the basis of class maximum demands, an allocation factor that is used to allocate distribution demand costs. In prior cases, the Companies' BIP allocator was used to allocate transmission costs, consistent with the Companies' approach of allocating production and integrated transmission system costs using the same allocation method. For the first time, to my knowledge, Mr. Seelye is proposing to allocate transmission plant using a distribution plant demand allocator.

Q. Doesn't Mr. Seelye state in his testimony at page 68, lines 9 and 10 (KU version) that he used the BIP allocator to allocate transmission costs to rate classes?

A. Yes. He testifies as follows: "Using this methodology 34.38% of KU's production and transmission fixed costs were assigned to the winter peak period…." In addition, his Figure 1 on page 66 of his testimony (KU version) clearly shows that transmission demand costs are assigned in the same manner as production demand costs, consistent with his approach in prior rate cases. However, that is not what Mr. Seelye's BIP and LOLP cost of service studies have used to assign and allocate transmission costs. As I discussed above, he used the same class maximum demand allocator that he uses to allocate more localized distribution costs.[4]

Q. Have you reviewed the Companies' alternative class cost of service studies using the LOLP methodology?

A. Yes. For the first time ever, the Companies' have prepared alternative class cost of service studies based on the LOLP methodology. In addition, the Companies' cost of service witness, Steven Seelye appears to place a greater reliance on the LOLP study results than on the BIP studies that the Companies have supported for many years.[5] The LOLP cost allocation method allocates production demand costs to rate classes based on a weighted hourly load allocator, with the weights based on the relative probability that there will be a loss of load (the inability to actually serve the load) in the hour. The hourly LOLP values are calculated in a production cost analysis that evaluates the system load in the hour, the generating capacity and firm purchases available to meet the load, and the expected availability of these resources to operate in the hour.

Based on Mr. Seelye's workpapers, of the total 8,760 hours during the projected test year, 12 months ending June 30, 2018, there were only 1,516 hours that had any material probability of such a loss of load; the other 7,244 hours had a "0" probability of load loss.[6] More importantly, when the amount of load loss is considered (referred to as Expected Unserved Energy), the total unserved energy for the year is 2,210 kWh. Of this, all but 4 kWh occurs during the summer months (2 kWh in the fall period, 2 kWh in the winter).[7]

Q. Mr. Seelye testifies on page 69 of his testimony (KU version) that LOLP is "a key measurement used by KU and LG&E to plan the system." Do the Companies actually use LOLP to plan generation resource additions?

A. Not really. Rather, the Companies use the results of an LOLP analysis, along with other information (for example, the cost of unserved energy) to determine an optimal

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[4] The only difference is that for rate classes that are served at transmission voltages and do not use the distribution system, these classes are excluded from the maximum class demand allocation of distribution costs.

[5] Seelye Direct Testimony at page 70, lines 15-19 (KU version).

[6] KU response to AG Set 1, Question 277, Attachment A. Also see KU response to PSC 3-46.

[7] The LOLP analysis does not assume any reliance on purchases from neighboring utilities, which ordinarily would prevent an actual loss of load event.

economic reserve margin. This is fully discussed in the Companies' 2014 Integrated Resource Plan, which contains the Companies' 2014 Reserve Margin Study. On page 25 of the 2014 Reserve Margin Study, the conclusions of the study are presented [see Baron Exhibit__(SJB-8)]. While on a straightforward LOLP basis, the Companies state that they would require a 21% reserve margin, the optimal economic reserve margin for the system is 16%, which is the planning criterion for adding additional resources. Based on the Companies' forecasts, the 16% reserve margin would be applied to the summer system peak. As such, summer system peak drives the need for capacity and individual class contributions to this summer CP would reflect a planning-based cost allocation method (this is generally referred to as the 1 CP cost allocation method).

Q. Does Mr. Seelye include capacity purchases in his LOLP analysis?

A. No. This is confirmed in the response to AG Set 1, Question 275(c) – "No market purchases were modeled for the LOLP study." Essentially, the LOLP analysis assumes that the KU/LG&E system is an "island" with no ties to the outside world. In reality, that is not true and that is one of the reasons why the actual planning reserve margin is 16% and not the 21% dictated by the LOLP analysis.

Q. Has the Companies' cost of service witness, Mr. Seelye ever presented a cost study using the LOLP methodology?

A. No. Based on his response to KIUC 1- 87, neither Mr. Seelye nor anyone else at his firm, The Prime Group, ever used or presented a class cost of service study based on the LOLP methodology.

Q. Are the Companies' aware of any other electric utility in the country that uses the LOLP methodology in a class cost of service study?

A. Apparently, the Companies are unable to identify a single other electric utility or regulatory commission that uses the LOLP method [(see response to PSC 2-78. Baron Exhibit__(SJB-3)].

Q. Should the Commission consider the results of the LOLP cost of service studies in deciding on an appropriate apportionment of the overall approved revenue increase to rate classes?

A. No. I don't believe that the Companies have presented anywhere near a sufficient level of evidence to support the adoption of this untried methodology. Furthermore, the LOLP cost of service studies for both Companies rely on the same erroneous hourly class load data as used in the BIP studies. The Commission should therefore not give any weight to the LOLP studies in this case.

III. APPORTIONMENT OF THE REVENUE INCREASE TO RATE CLASSES

Q. How are the Companies proposing to apportion the overall revenue increase to rate classes in this case?

A. Tables 5 and 6 below summarize the LG&E and KU rate class revenue increases proposed by the Companies in this case.

Table 5
LG&E Proposed Rate Class Revenue Increases

Rate Class	Total Revenue at Current Rates	Total Revenue at Proposed Rates	Change in Total Revenue	Percent Change
RS	$ 441,462,416	$ 483,588,845	$ 42,126,429	9.54%
RTOD	$ 55,652	$ 60,958	$ 5,306	9.53%
GS, GS3	$ 170,461,520	$ 182,642,225	$ 12,180,705	7.15%
PSS	$ 164,895,598	$ 176,526,765	$ 11,631,167	7.05%
PSP	$ 12,536,325	$ 13,570,842	$ 1,034,517	8.25%
TODS	$ 84,439,205	$ 90,137,293	$ 5,698,088	6.75%
TODP	$ 126,370,424	$ 136,755,655	$ 10,385,231	8.22%
RTS	$ 68,895,503	$ 74,719,968	$ 5,824,465	8.45%
FLS	$ -	$ -	$ -	
LE	$ 244,537	$ 244,537	$ -	0.00%
TE	$ 304,220	$ 324,800	$ 20,580	6.76%
LS, RLS	$ 23,389,325	$ 25,309,553	$ 1,920,228	8.21%
Sp Contracts	$ 10,274,768	$ 11,167,899	$ 893,131	8.69%
Total	$ 1,103,329,493	$ 1,195,049,340	$ 91,719,847	8.31%
CSR	$ (4,334,522)	$ (2,414,251)	$ 1,920,271	44.30%
Retail Revenues	$ 1,098,994,971	$ 1,192,635,089	$ 93,640,118	8.52%

Table 6
KU Proposed Rate Class Revenue Increases

Rate Class	Total Revenue at Present Rates	Total Revenue at Proposed Rates	Change in Total Revenue	Percent Change
RS	$ 622,779,411	$ 659,777,674	$ 36,998,263	5.94%
RTOD	$ 30,441	$ 32,241	$ 1,800	5.91%
GS, GS3	$ 239,171,377	$ 251,265,831	$ 12,094,454	5.06%
AES, AES3	$ 14,562,100	$ 15,339,251	$ 777,151	5.34%
PSS	$ 187,147,175	$ 196,625,481	$ 9,478,306	5.06%
PSP	$ 14,972,312	$ 15,678,164	$ 705,852	4.71%
TODS	$ 123,707,658	$ 130,573,606	$ 6,865,948	5.55%
TODP	$ 262,428,533	$ 279,764,084	$ 17,335,551	6.61%
RTS	$ 89,717,941	$ 95,740,763	$ 6,022,822	6.71%
FLS	$ 30,814,610	$ 33,049,624	$ 2,235,014	7.25%
LE	$ 35,467	$ 35,467	$ -	0.00%
TE	$ 173,457	$ 181,632	$ 8,175	4.71%
LS, RLS	$ 30,389,694	$ 32,256,178	$ 1,866,484	6.14%
Total	$1,615,930,178	$1,710,319,998	$ 94,389,820	5.84%
CSR	$ (17,395,776)	$ (8,707,401)	$ 8,688,375	49.95%
Retail Revenues	$1,598,534,402	$1,701,612,597	$ 103,078,195	6.45%

Both Companies relied on the results of the filed BIP and LOLP cost of service studies to determine the revenue increases for each rate class.[8]

Q. Do you support the Companies' proposed rate class revenue apportionments?

A. No. As I discussed in the previous section of my testimony, there are significant and material problems with the Companies' class cost of service studies. These problems are primarily due to the use of erroneous projected hourly load data and

[8] Seelye LG&E Direct Testimony at page 7; Seelye KU Direct Testimony at page 6.

the reliance on these data to calculate production, transmission and distribution demand allocation factors. As a result, even if the Commission were inclined to accept either the BIP or LOLP cost of service methods, the studies presented by the Companies cannot be relied on in this case. Moreover, I have identified significant methodological problems with the BIP and LOLP cost of service studies irrespective of the load data issues. <u>For these reasons, I believe that the Companies' proposed revenue increase apportionment should be rejected and a simple, uniform percentage increase be used to allocate the approved revenue increase in this case to rate classes.</u> Since the cost of service results cannot be relied on, the only reasonable alternative is to uniformly increase the rates to each rate class.

Q. Are there other factors that the Commission should consider?

A. Yes. The Commission should consider the overall impact on large industrial customers, particularly manufacturing customers on the State's economic development. KIUC's recommended uniform percentage increases for each of LG&E's and KU's rate classes provides some mitigation of the impact of the Companies' requested revenue increases to both residential customers and large industrial customers who, unlike smaller commercial customers, face competition from outside Kentucky and bring export dollars into the economy. Commercial customers tend to be population based and face local competition so that there are minimal differences in power costs among competitors. That is one important reason why there are big box retailers and fast food restaurants in Alaska and Hawaii paying electric rates multiple times higher than in Kentucky, but there are no steel, chemical or auto plants in those states. This is in contrast to large industrial manufacturing customers that face national and international competition. KIUC's recommendation considers cost of service principles and serves a broader interest by helping to insure the competiveness of Kentucky high wage, high benefit and family supportive manufacturing jobs. I should also note that manufacturing jobs tend to have high job multipliers. That is, for every one manufacturing job created or saved about two additional support-related jobs are created.

Tables 7 and 8 present KIUC's proposed rate schedule revenue increases for LG&E and KU. These revenue increases do not reflect the KIUC recommended CSR rates discussed by KIUC witness Dennis Goins. Of course, to the extent that the Commission authorizes a lower overall increase for either Company, the increases shown in Tables 7 and 8 should be adjusted on a proportionate basis consistent with the Commission's authorized revenue increase.

Table 7
KIUC Proposed LG&E Rate Class Revenue Increases*

Rate Class	Total Revenue at Current Rates	Total Revenue at Proposed Rates	Change in Total Revenue	Percent Change
RS	$ 441,462,416	$ 478,161,213	$ 36,698,797	8.31%
RTOD	$ 55,652	$ 60,278	$ 4,626	8.31%
GS, GS3	$ 170,461,520	$ 184,631,996	$ 14,170,476	8.31%
PSS	$ 164,895,598	$ 178,603,379	$ 13,707,781	8.31%
PSP	$ 12,536,325	$ 13,578,470	$ 1,042,145	8.31%
TODS	$ 84,439,205	$ 91,458,641	$ 7,019,436	8.31%
TODP	$ 126,370,424	$ 136,875,605	$ 10,505,181	8.31%
RTS	$ 68,895,503	$ 74,622,790	$ 5,727,287	8.31%
FLS	$ -	$ -	$ -	
LE	$ 244,537	$ 264,865	$ 20,328	8.31%
TE	$ 304,220	$ 329,510	$ 25,290	8.31%
LS, RLS	$ 23,389,325	$ 25,333,681	$ 1,944,356	8.31%
Sp Contracts	$ 10,274,768	$ 11,128,910	$ 854,142	8.31%
Total	$ 1,103,329,493	$ 1,195,049,340	$ 91,719,847	8.31%

* Does not reflect any Commission approved revenue requirement adjustments, such as those recommended by KIUC.

Table 8
KIUC Proposed KU Rate Class Revenue Increases*

Rate Class	Total Revenue at Present Rates	Total Revenue at Proposed Rates	Change in Total Revenue	Percent Change
RS	$ 622,779,411	$ 659,157,243	$ 36,377,832	5.84%
RTOD	$ 30,441	$ 32,219	$ 1,778	5.84%
GS, GS3	$ 239,171,377	$ 253,141,871	$ 13,970,494	5.84%
AES, AES3	$ 14,562,100	$ 15,412,702	$ 850,602	5.84%
PSS	$ 187,147,175	$ 198,078,828	$ 10,931,653	5.84%
PSP	$ 14,972,312	$ 15,846,876	$ 874,564	5.84%
TODS	$ 123,707,658	$ 130,933,678	$ 7,226,020	5.84%
TODP	$ 262,428,533	$ 277,757,526	$ 15,328,993	5.84%
RTS	$ 89,717,941	$ 94,958,551	$ 5,240,610	5.84%
FLS	$ 30,814,610	$ 32,614,556	$ 1,799,945	5.84%
LE	$ 35,467	$ 37,539	$ 2,072	5.84%
TE	$ 173,457	$ 183,589	$ 10,132	5.84%
LS, RLS	$ 30,389,694	$ 32,164,819	$ 1,775,125	5.84%
Total	$1,615,930,178	$1,710,319,998	$ 94,389,820	5.84%

* Does not reflect any Commission approved revenue requirement adjustments, such as those recommended by KIUC.

Q. KIUC is recommending significant adjustments to the Companies' overall revenue increases in this case. In the event that the Commission adopts KIUC's position, do you have a recommended allocation of such a decrease?

A. Yes. I recommend that any approved overall revenue increase (or decrease) be allocated on a uniform basis to each rate schedule.

IV. RATE DESIGN ISSUES

Q. Are the Companies proposing any significant rate design changes for its large customer, demand metered rate classes?

A. Yes. As discussed by Companies' witness Steven Seelye, the Companies are proposing to increase the current 75% demand ratchet to a 100% ratchet for the based demand charges for rate schedules TOD-S, TOD-P, RTS and FLS. This change would only apply to the base demand charges of these rates, not the peak and intermediate period demand charges.

Q. Have you reviewed the Companies' support for this change?

A. Yes. The Companies' argument in support of this rate design change is that the base demand charge is designed to recover distribution and transmission related fixed demand costs that are incurred on the basis of maximum rate class demands and maximum customer demands.[9] As such, a 100% ratchet tied to a customer's maximum demand in the current month or the preceding 11 months more closely followings cost, than the current 75% ratchet. The Companies' argument appears to be reasonable and I therefore do not oppose this rate design revision.

[9] This is confirmed by the Companies' in response to KIUC 1-96.

V. AUTOMATIC METERING SYSTEM COST RECOVERY

Q. Would you please discuss the Companies' proposal to deploy AMS on their respective systems beginning in 2017?

A. As described by Companies' witness John Malloy in his testimony, the Companies are proposing to replace their entire stock of electric meters with AMS beginning in the third quarter of 2017, 4 months or more after intervenor testimony is due to be filed in this case. LGE is anticipating deploying 418,000 electric meters and KU will deploy 530,000 meters in its Kentucky jurisdiction. These deployments will continue through 2019. As more fully discussed by KIUC witness Kollen, the Companies have included substantial revenue requirements associated with these investments in the projected test year ending June 2018. He is recommending denying the Companies request in this case, effectively reducing each Companies test year rate increase by the amounts of projected costs associated with AMS.

Q. Do you have an alternative recommendation to recover the AMS costs, in the event that the Commission authorizes this deployment and recovery of the costs in the test year?

A. Yes. Given the uncertainty surrounding the test year projections associated with AMS, I recommend that the Commission adopt a separate AMS rider for each Company that would only recover costs that are actually expended instead of including such costs in the base revenue requirements. This would include a return on CWIP and plant associated with the AMS deployment, depreciation, incremental O&M expenses, taxes and other revenue requirement related items. Mr. Kollen discusses the specific items that should be permitted in the rider revenue requirement calculation.

Q. Would you explain how often the rider would be adjusted?

A. My proposal is to permit the Companies to adjust the rider quarterly, as new AMS investment is actually incurred. The Companies would not be permitted to include forecasted costs. This approach is similar to the Companies' environmental surcharge riders, where costs are included only after they are actually incurred. A rider would take the guess work out of this future test year projection for this new AMS undertaking by ensuring recovery of only actually incurred and Commission approved costs.

Q. How should the AMS costs be recovered from ratepayers?

A. The new AMS rider should be recovered on a per customer (per meter) basis. AMS investment costs are primarily, and perhaps fully, included in FERC Account No. 370, meters. Normally, meter costs are assigned to rate classes in a class cost of service study on a weighted customer basis. The weights reflect the different investment costs associated with secondary, primary and higher voltage transmission level meters. However, the Companies have stated that they do not intend to replace their current MV90 type meters with AMS [see response to KIUC 2-23 attached as

Baron Exhibit__(SJB-9)]. Based on the Companies' response to KIUC Set 2, Question No. 22, these MV90 meters serve almost 100% of the customers on rate schedules TOD-S, TOD-P, RTS and FLS [(see Baron Exhibit__(SJB-10)]. As such, it is likely that very little, if any, of the AMS investment and expenses is attributable to these larger rate schedules. However, to simplify cost recovery of AMS in a rider, my recommendation is to simply recover the revenue requirement on a per customer basis.[10]

Q. Have other jurisdictions used a per meter rider to recover AMS type investments?

A. Yes. PPL Electric Utilities Corporation, an affiliate of LGE and KU, recovers smart meter costs through a per meter rider that is adjusted quarterly. Baron Exhibit__(SJB-11) contains a copy of the PPL Smart Meter Riders for Phase 1 and Phase 2.

In Ohio, AEP Ohio recovers AMS type costs through a "gridSmart" rider. This rider, which is updated and trued-up annually recovers other advanced smart grid type costs, in addition to advanced metering costs. AEP Ohio's gridsmart costs are recovered on a per customer (per meter) basis. Attached as Baron Exhibit__(SJB-12) is a copy of the AEP Ohio gridSmart rider.

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[10] As confirmed in the Companies' response to KIUC

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Sworn to and subscribed before me on this
28th day of February 2017.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00371**

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has more than thirty-five years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, he joined the consulting firm of Kennedy and Associates as a Vice President and Principal. Mr. Baron became President of the firm in January 1991.

During the course of his career, he has provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

**Expert Testimony Appearances
of
Stephen J. Baron
As of January 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

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	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

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8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

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8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

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8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

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4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035- E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

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7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177- E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider

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Date	Case	Jurisdict.	Party	Utility	Subject
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1272 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012-00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider

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Date	Case	Jurisdict.	Party	Utility	Subject
6/12	12-0399- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A- 12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A- 12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/13	13-0462-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764-E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013-2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
5/14	14-0344-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
7/14	PUE-2014-00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014	VA	Old Dominion Committee	Appalachian Power	Biennial Review Case - Cost

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Date	Case	Jurisdict.	Party	Utility	Subject
	-00026			Company	of Service Issues
9/14	14-841-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
12/14	EL14-026	SD	Black Hills Power Industrial Intervenors	Black Hills Power, Inc.	Cost of Service Issues
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design transmission, lost revenues
2/15	14-1297 El-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Interruptible load
615	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
5/15	15-0301-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/15	D2015-6.51	MT	Montana Large Customer Group	Montana Dakota Utilities Co.	Class Cost of Service, Rate Design
11/15	15-1351-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")

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Date	Case	Jurisdict.	Party	Utility	Subject
3/16	EL01-88 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Bandwidth Tariff
5/16	16-0239-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
6/16	E-01933A-15-0322	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
6/16	16-00001	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
6/16	14-1297 El-SS0-Rehearing	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
7/16	160021-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/16	16AL-0048E	CO	CF&I.Steel LP Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
7/16	16-0403-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Response
10/16	16-1121-E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost (“ENEC”)
11/16	16-0395-EL-SSO	OH	Ohio Energy Group	Dayton Power & Light	Electric Security Rate Plan
11/16	EL09-61-004 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/16	1139	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design
1/17	E-01345A-16-0036	AZ	Kroger	Arizona Public Service Co.	Cost of Service, Rate Design
2/17	16-1026-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Purchase Power Agreement

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017**

Question No. 87

Responding Witness: William S. Seelye

Q.1-87. Please provide any testimony, papers or presentations prepared by Mr. Seelye or any other employee of the Prime Group in the past ten years which addresses the LOLP cost of service methodology. This would include all testimony, papers or presentations supporting the LOLP method and testimony opposing the LOLP method.

A.1-87. These are the first proceedings in which Mr. Seelye or other employees of The Prime Group have submitted a cost of service study using the LOLP methodology.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to Commission Staff's Second Request for Information
Dated January 11, 2017**

Question No. 78

Responding Witness: William S. Seelye

Q-78. Refer to the Seelye Testimony, page 2, lines 7-10.

a. State whether KU is aware of the Commission's approving a Loss of Load Probability Cost of Service Study ("LOLP COSS") in another proceeding. If so, provide the case number of the proceeding.

b. State whether KU is aware of a LOLP COSS's having been approved in other state jurisdictions. If so, provide the state and docket number.

A-78.

a. The Company is unaware of the Commission's ever having approved a LOLP COSS in another proceeding.

b. The Company is unaware of a LOLP COSS being approved in another state jurisdiction. The Company is introducing the LOLP COSS *as an alternative* because an LOLP allocator is consistent with the way that generation resources have been planned for several decades.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 274

Responding Witness: William S. Seelye / David S. Sinclair

Q-274. With regard to Mr. Seelye's Loss of Load Probability ("LOLP") study, he indicates that hourly loads were utilized for individual classes. In this respect, provide:

a. a detailed narrative description of how class hourly loads were developed;

b. each class hourly load for the forecasted test year (or the period utilized by Mr. Seelye within his CCOSS). Because of the joint dispatch of the Companies' generation facilities, include both KU and LG&E classes (showing KU and LG&E classes separately). In addition, also include each non-jurisdictional class;

c. a detailed explanation of how curtailable load or curtailable load credits are reflected within the class hourly loads;

d. all workpapers, analyses, spreadsheets, etc. showing the development of each hourly load for each class; and,

e. an explanation of whether the hourly loads provided in (b) are measured at the meter or generation level.

Provide all data in hardcopy as well as in executable electronic format. Excel preferred. If data is not available in Excel format, provide ASCII comma-delimited format with all fields defined.

A-274.

a. The following process was used to develop hourly class load profiles for the forecasted test year.

1. Hourly class load profiles for the 12 months ending June 2016 ("Historical Period") are developed using 5- and 15-minute interval data from the MV-90 system.
    a. For each month in the Historical Period, the sum of each class's hourly loads equals the class's actual monthly energy

consumption derived from monthly billing data in the Customer Care System ("CCS").

b. For each hour in the Historical Period, each class's share of the Company's actual hourly load is computed with an appropriate adjustment for losses ("Hourly Class Ratio").

c. For each hour in the Historical Period, the sum of all class loads plus distribution and transmission losses and company uses equals the Company's actual hourly load in the Energy Management System ("EMS").

2. For each month in the Historical Period, the Company's hourly class loads are totaled for each day and the daily totals are sorted from highest to lowest.
3. For each month in the forecasted test period, the Company's hourly load forecast is totaled for each day and the daily totals are sorted from highest to lowest.
4. To develop hourly class load profiles for the forecasted test period (July 2017 to June 2018), the hourly load for each day in the hourly load forecast (as ordered in Step 3) is multiplied by the corresponding day's Hourly Class Ratios (as ordered in Step 2).
   a. For each month in the forecasted test period, the sum of each class's hourly loads equals the class's forecasted monthly energy consumption.
   b. For each hour in the forecasted test period, the sum of class loads plus forecasted distribution and transmission losses and forecasted company uses equals the Companies' forecasted hourly load.

b. See the attachment to PSC 2-97.

c. The impact of curtailable loads is not reflected in the hourly class load profiles. See the response to KIUC 1-56.

d. See the attachments being provided in Excel format.

e. The hourly loads used in developing the LOLP allocator were based on hourly loads including losses. Therefore, the loads measured were at the generation level.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

DISCUSSION OF KU/LG&E HOURLY LOAD DATA PROJECTION ERROR

The Companies' developed a set of 8,760 hourly loads for each rate class for the 12 month period ending June 30, 2018. As discussed below in detail, the process began with actual hourly loads for an historic period (12 months ending June 30, 2016). Through multiple adjustments, the historic hourly load data was projected and then re-ordered to match a separate Energy Management System hourly load forecast for the total system. As discussed below, there was a significant error made in the re-ordering process that resulted in erroneous hourly load data and cost of service study demand allocation factors. Because the class cost of service studies rely directly on rate class demand allocation factors to assign cost responsibility, the errors in the Companies rate class demand allocation factors result in unreliable and unusable cost of service study results. The specific process used by the Companies is explained below:

1. Adjust the actual hourly loads, based either on actual data for the class in the case of KU FLS or sample load research data for all other classes to match the actual kWh sales for the class on a monthly basis. This adjustment sums the hourly loads for the month and compares this monthly total to the actual kWh sales. This produces a set of actual hourly loads for the 8,760 hours during the period July 1, 2015 through June 30, 2016.

2. For each hour of the historic year, these actual data are then summed for all rate classes (except FLS, Lighting and a few others) and adjusted to match the

Companies' Energy Management System ("EMS") actual hourly mW loads. The EMS loads are the actual loads from the Companies' dispatch system.

3. Adjust the historic period hourly loads (from Step 2) to reflect the 2018 forecasted test year energy, by rate class, by month. This calculation is performed on a rate class by rate class basis by summing the historic period hourly loads for each month for the class (this produces the implied kWh energy for the class that corresponds to the hourly loads) and adjusting each hourly load so that the monthly total (kWh energy) matches the test year sales forecast for the rate class that month.

4. The results of Step 3 are then re-ordered so that, on a daily basis, the day's hourly loads during the month for the forecast based on the buildup of class data matches the same order of daily loads in the month for the system load shape used in generation planning (the projected test year EMS load shape). Thus, for example, if the EMS load shape forecast shows that the 9th highest day in August 2017 is August 29th, then the 9th highest day of the class load forecast (from Step 3) now becomes August 29th. This process was designed to re-order the daily load shape of the class forecast to match the EMS forecast. In the Companies' workpapers, the 9th highest day for the class based hourly load forecast is August 12th, so the class loads on this day should now become the class loads for August 29th (based on the data in Step 3). Again, the purpose was to conform the class load forecast to the separate EMS load forecast used for generation planning.

5. Finally, the last step in the Companies' process is to sum up the loads in each hour for all rate classes (except Lighting) and adjust them by a factor calculated for that hour so that the total of the class loads matches the EMS hourly system load forecast.

Unfortunately, the Companies erred in implementing their intended method for the re-ordering process in Step 4. In this re-ordering process, the Companies intended for August 12th class load shape data to become August 29th data – thus matching the EMS load shape ordering used for generation planning on the 9th highest day expected for the System in August 2017, and described in Step 4 above. In error, the Companies re-ordered the class hourly loads for that day (August 12th) as August 9th (substituting the rank number for the day of the month), not the intended August 29th. These incorrectly ordered hourly loads are then adjusted as described in Step 5, and used to determine the demand allocation factors Mr. Seelye uses in his class cost of service studies. Attachment 1 contains an excerpt from the KU re-ordering calculation ("ranking"). It shows that the 9th highest day ("rank") in the class load data (the right-hand set of columns) is August 12th, while the 9th highest day in the EMS data (left-hand set of columns) is August 29th. The column in the middle, under the phrase "Day in Forward Test Year", identifies that August 12 in the class load data is the appropriate match, and so the class loads for August 12th should have been re-ordered to have a date of August 29th. Instead, they were incorrectly assigned to be the loads for August 9th. The final adjustment in Step 5 attempts to match the hourly class loads to the EMS load for the same date and hour, but the matching adjustment is meaningless because of the wrong dates assigned in the ranking. <u>As a result, the resulting hourly adjustment factors (Step 5) are much more extreme than they would be had the</u>

ordering been done correctly. This was a major cause of the erroneous demand allocation factors, but not the only cause, as I will explain later.

This re-ordering problem can easily be seen in the Companies' workpapers. Attachment 2, pages 1 to 3 show the problem. As I indicated above, the hourly class loads for August 12th were the 9th highest of the month. Page 1 of Attachment 2 shows an excerpt from the Companies' workpapers [AG 1-274(d)], highlighting the residential load on August 12th from hour 15. This is the value for the residential class developed in Step 2 above (1,083,626 kW). Page 2 shows the same residential data for August 12th at hour 15, except that it has been adjusted by the final EMS load shape factor of 1.14257 (1,238,118 kW, after adjustment by this factor). This adjustment was discussed in Step 5.

This same factor is applied to the loads of each rate class in that hour. The factor is based on a reconciliation of the class hourly loads with the EMS loads on August 9th at hour 15. Recall that the 9th highest EMS load occurred on August 29th, not August 9th. The adjustment was intended to reconcile the class loads of August 12th to the EMS load on August 29th (the 9th highest day in the EMS load shape). Page 3 of Attachment 2 shows the final re-ordering that now changes the date for these class loads (residential load of 1,238,118 kW) to August 9th at hour 15, rather than the intended August 29th at hour 15.

Forecast Year	Month	Day	Sum of KU	Rank	Day in Forward Test Year	Forward Test Year Year	Month	Day	Sum of Total KU	Rank
2017	8	1	68,528	13	14	2017	8	1	64,047,393	18
2017	8	2	70,463	11	20	2017	8	2	61,224,240	27
2017	8	3	69,536	12	13	2017	8	3	73,884,203	3
2017	8	4	65,756	20	15	2017	8	4	75,349,177	1
2017	8	5	59,455	25	23	2017	8	5	71,938,605	7
2017	8	6	64,388	24	27	2017	8	6	65,221,251	15
2017	8	7	74,318	4	11	2017	8	7	64,115,234	17
2017	8	8	70,844	10	17	2017	8	8	61,511,394	26
2017	8	9	77,631	1	4	2017	8	9	62,274,905	23
2017	8	10	73,030	7	5	2017	8	10	73,161,415	5
2017	8	11	66,978	18	1	2017	8	11	73,252,963	4
2017	8	12	56,718	27	2	2017	8	12	69,532,259	9
2017	8	13	52,761	30	26	2017	8	13	66,883,031	12
2017	8	14	67,337	17	7	2017	8	14	66,725,274	13
2017	8	15	72,685	8	31	2017	8	15	63,033,079	20
2017	8	16	76,449	2	19	2017	8	16	63,995,690	19
2017	8	17	74,292	5	10	2017	8	17	68,080,129	10
2017	8	18	67,607	16	28	2017	8	18	72,584,441	6
2017	8	19	55,954	29	25	2017	8	19	74,021,659	2
2017	8	20	52,444	31	22	2017	8	20	67,604,902	11
2017	8	21	65,017	23	9	2017	8	21	62,618,901	22
2017	8	22	68,393	14	24	2017	8	22	57,992,348	31
2017	8	23	66,499	19	16	2017	8	23	61,788,106	25
2017	8	24	65,702	21	29	2017	8	24	65,643,657	14
2017	8	25	65,596	22	21	2017	8	25	60,579,193	29
2017	8	26	56,728	26	8	2017	8	26	59,949,005	30
2017	8	27	56,174	28	30	2017	8	27	61,875,284	24
2017	8	28	68,300	15	6	2017	8	28	64,657,162	16
2017	8	29	72,380	9	12	2017	8	29	62,734,839	21
2017	8	30	74,242	6	18	2017	8	30	60,689,098	28
2017	8	31	74,339	3	3	2017	8	31	71,901,798	8

ObsTime	Year	Month	Day	Hour	Order Day	S Residential 1	S General Service 100	GS 1Phase 101
8/12/2017 13:00	2017	8	12	13	9	889,011	403,944	164,193
8/12/2017 14:00	2017	8	12	14	9	967,095	393,168	159,813
8/12/2017 15:00	2017	8	12	15	9	1,083,626	324,504	131,903
8/12/2017 16:00	2017	8	12	16	9	1,157,009	279,976	113,803
8/12/2017 17:00	2017	8	12	17	9	1,179,204	260,500	105,887
8/12/2017 18:00	2017	8	12	18	9	1,118,640	258,092	104,908
8/12/2017 19:00	2017	8	12	19	9	1,058,071	231,403	94,060
8/12/2017 20:00	2017	8	12	20	9	994,669	203,873	82,869
8/12/2017 21:00	2017	8	12	21	9	843,819	180,456	73,351
8/12/2017 22:00	2017	8	12	22	9	680,088	159,391	64,789
8/12/2017 23:00	2017	8	12	23	9	575,695	145,163	59,005
8/17/2017 0:00	2017	8	17	0	10	607,162	139,059	56,524
8/17/2017 1:00	2017	8	17	1	10	553,349	137,627	55,942
8/17/2017 2:00	2017	8	17	2	10	511,541	133,833	54,400
8/17/2017 3:00	2017	8	17	3	10	503,730	136,616	55,531
8/17/2017 4:00	2017	8	17	4	10	527,719	152,141	61,841
8/17/2017 5:00	2017	8	17	5	10	551,614	213,843	86,922
8/17/2017 6:00	2017	8	17	6	10	563,492	302,277	122,868
8/17/2017 7:00	2017	8	17	7	10	562,825	316,976	128,843
8/17/2017 8:00	2017	8	17	8	10	584,268	342,335	139,151
8/17/2017 9:00	2017	8	17	9	10	666,853	350,200	142,348

Attachment to Response to AG-1 Question No. 274(d)
Page 1 of 1
Seelye/Sinclair

ObsTime	Year	Month	Day	Hour	Order Day	S Residential 1	S General Service 100	GS 1Phase 101
8/12/2017 8:00	2017	8	12	8	9	573,195	433,837	176,344
8/12/2017 9:00	2017	8	12	9	9	696,827	445,081	180,914
8/12/2017 10:00	2017	8	12	10	9	823,407	456,425	185,526
8/12/2017 11:00	2017	8	12	11	9	883,590	459,178	186,645
8/12/2017 12:00	2017	8	12	12	9	936,759	453,862	184,484
8/12/2017 13:00	2017	8	12	13	9	1,019,510	463,240	188,296
8/12/2017 14:00	2017	8	12	14	9	1,095,114	445,214	180,968
8/12/2017 15:00	2017	8	12	15	9	1,238,118	370,768	150,708
8/12/2017 16:00	2017	8	12	16	9	1,319,718	319,348	129,807
8/12/2017 17:00	2017	8	12	17	9	1,336,382	295,223	120,001
8/12/2017 18:00	2017	8	12	18	9	1,292,151	298,124	121,180
8/12/2017 19:00	2017	8	12	19	9	1,254,647	274,395	111,535
8/12/2017 20:00	2017	8	12	20	9	1,167,131	239,222	97,238
8/12/2017 21:00	2017	8	12	21	9	961,096	205,537	83,546
8/12/2017 22:00	2017	8	12	22	9	768,013	179,998	73,165
8/12/2017 23:00	2017	8	12	23	9	633,298	159,688	64,909
8/17/2017 0:00	2017	8	17	0	10	664,145	152,110	61,829
8/17/2017 1:00	2017	8	17	1	10	591,949	147,227	59,844
8/17/2017 2:00	2017	8	17	2	10	562,447	147,152	59,814
8/17/2017 3:00	2017	8	17	3	10	529,776	143,679	58,402

ObsTime	Year	Month	Day	Hour	Order Day	S Residential 1	S General Service 100
8/9/2017 8:00	2017	8	12	8	9	573,195	433,837
8/9/2017 9:00	2017	8	12	9	9	696,827	445,081
8/9/2017 10:00	2017	8	12	10	9	823,407	456,425
8/9/2017 11:00	2017	8	12	11	9	883,590	459,178
8/9/2017 12:00	2017	8	12	12	9	936,759	453,862
8/9/2017 13:00	2017	8	12	13	9	1,019,510	463,240
8/9/2017 14:00	2017	8	12	14	9	1,095,114	445,214
8/9/2017 15:00	**2017**	**8**	**12**	**15**	**9**	**1,238,118**	370,768
8/9/2017 16:00	2017	8	12	16	9	1,319,718	319,348
8/9/2017 17:00	2017	8	12	17	9	1,336,382	295,223
8/9/2017 18:00	2017	8	12	18	9	1,292,151	298,124
8/9/2017 19:00	2017	8	12	19	9	1,254,647	274,395
8/9/2017 20:00	2017	8	12	20	9	1,167,131	239,222
8/9/2017 21:00	2017	8	12	21	9	961,096	205,537
8/9/2017 22:00	2017	8	12	22	9	768,013	179,998
8/9/2017 23:00	2017	8	12	23	9	633,298	159,688

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

THESE COLUMNS ARE FROM THE COMPANY'S WORKPAPER

EMS FORECAST SUMMED BY DAY

Forecast

Year	Month	Day	Sum of KU	Rank	Day in Forward Test Year
2017	8	1	68,528	13	14
2017	8	2	70,463	11	20
2017	8	3	69,536	12	13
2017	8	4	65,756	20	15
2017	8	5	59,455	25	23
2017	8	6	64,388	24	27
2017	8	7	74,318	4	11
2017	8	8	70,844	10	17
2017	8	9	77,631	1	4
2017	8	10	73,030	7	5
2017	8	11	66,978	18	1
2017	8	12	56,718	27	2
2017	8	13	52,761	30	26
2017	8	14	67,337	17	7
2017	8	15	72,685	8	31
2017	8	16	76,449	2	19
2017	8	17	74,292	5	10
2017	8	18	67,607	16	28
2017	8	19	55,954	29	25
2017	8	20	52,444	31	22
2017	8	21	65,017	23	9
2017	8	22	68,393	14	24
2017	8	23	66,499	19	16
2017	8	24	65,702	21	29
2017	8	25	65,596	22	21
2017	8	26	56,728	26	8
2017	8	27	56,174	28	30
2017	8	28	68,300	15	6
2017	8	29	72,380	9	12
2017	8	30	74,242	6	18
2017	8	31	74,339	3	3

CLASS LOADS ADJUSTED TO FORECAST BY DAY

Forward Test Year

Year	Month	Day	Sum of Total KU	Rank
2017	8	1	64,047,393	18
2017	8	2	61,224,240	27
2017	8	3	73,884,203	3
2017	8	4	75,349,177	1
2017	8	5	71,938,605	7
2017	8	6	65,221,251	15
2017	8	7	64,115,234	17
2017	8	8	61,511,394	26
2017	8	9	62,274,905	23
2017	8	10	73,161,415	5
2017	8	11	73,252,963	4
2017	8	12	69,532,259	9
2017	8	13	66,883,031	12
2017	8	14	66,725,274	13
2017	8	15	63,033,079	20
2017	8	16	63,995,690	19
2017	8	17	68,080,129	10
2017	8	18	72,584,441	6
2017	8	19	74,021,659	2
2017	8	20	67,604,902	11
2017	8	21	62,618,901	22
2017	8	22	57,992,348	31
2017	8	23	61,788,106	25
2017	8	24	65,643,657	14
2017	8	25	60,579,193	29
2017	8	26	59,949,005	30
2017	8	27	61,875,284	24
2017	8	28	64,657,162	16
2017	8	29	62,734,839	21
2017	8	30	60,689,098	28
2017	8	31	71,901,798	8

CLASS LOADS RE-SORTED HOW THE COMPANY WANTED TO

Year	Month	Day	Sum of Total KU	Rank
2017	8	14	66,725,274	13
2017	8	20	67,604,902	11
2017	8	13	66,883,031	12
2017	8	15	63,033,079	20
2017	8	23	61,788,106	25
2017	8	27	61,875,284	24
2017	8	11	73,252,963	4
2017	8	17	68,080,129	10
2017	8	4	75,349,177	1
2017	8	5	71,938,605	7
2017	8	1	64,047,393	18
2017	8	2	61,224,240	27
2017	8	26	59,949,005	30
2017	8	7	64,115,234	17
2017	8	31	71,901,798	8
2017	8	19	74,021,659	2
2017	8	10	73,161,415	5
2017	8	28	64,657,162	16
2017	8	25	60,579,193	29
2017	8	22	57,992,348	31
2017	8	9	62,274,905	23
2017	8	24	65,643,657	14
2017	8	16	63,995,690	19
2017	8	29	62,734,839	21
2017	8	21	62,618,901	22
2017	8	8	61,511,394	26
2017	8	30	60,689,098	28
2017	8	6	65,221,251	15
2017	8	12	69,532,259	9
2017	8	18	72,584,441	6
2017	8	3	73,884,203	3

HOW THE COMPANY ACTUALLY RE-SORTED THE CLASS LOADS

Year	Month	Day	Sum of Total KU	Rank
2017	8	4	75,349,177	1
2017	8	19	74,021,659	2
2017	8	3	73,884,203	3
2017	8	11	73,252,963	4
2017	8	10	73,161,415	5
2017	8	18	72,584,441	6
2017	8	5	71,938,605	7
2017	8	31	71,901,798	8
2017	8	12	69,532,259	9
2017	8	17	68,080,129	10
2017	8	20	67,604,902	11
2017	8	13	66,883,031	12
2017	8	14	66,725,274	13
2017	8	24	65,643,657	14
2017	8	6	65,221,251	15
2017	8	28	64,657,162	16
2017	8	7	64,115,234	17
2017	8	1	64,047,393	18
2017	8	16	63,995,690	19
2017	8	15	63,033,079	20
2017	8	29	62,734,839	21
2017	8	21	62,618,901	22
2017	8	9	62,274,905	23
2017	8	27	61,875,284	24
2017	8	23	61,788,106	25
2017	8	8	61,511,394	26
2017	8	2	61,224,240	27
2017	8	30	60,689,098	28
2017	8	25	60,579,193	29
2017	8	26	59,949,005	30
2017	8	22	57,992,348	31

THESE RANKS MATCH

FINAL RANKS MATCH THE DAY OF THE MONTH

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
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$25.00

principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

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.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

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.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. 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 occurring 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 manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

2014 Reserve Margin Study

PPL companies

Generation Planning & Analysis
March 2014

higher and 25% lower. Changing scarcity prices has a notable impact on scarcity costs but a relative small impact on the economic reserve margin range.

5.2.4 Unit Availability

As units become less available, the likelihood of experiencing generation shortages during scarcity events increases and the economic reserve margin range increases. Based on benchmarking data, the Companies' generating units rank in the top quartile for unit availability metrics; the risk of poorer performance is greater than the risk of better performance. For this reason, the Companies considered the following unit availability sensitivities:

- Increase EFOR by 1.5 points
- Decrease EFOR by 0.5 points

Compared to other sensitivities, unit availability has a fairly significant impact on the economic reserve margin range. If EFOR increases by 1.5 percentage points, the economic reserve margin range is 2.25% to 2.75% higher. If EFOR decreases by 0.5 percentage points, the economic reserve margin range is 0.5% to 1.0% lower. Based on these results, maintaining top quartile unit availability is very important for the Companies.

5.2.5 Power Import Capability

As mentioned in Section 4.2, reserve margins in neighboring regions are expected to decline precipitously over the next several years with the retirement of coal units. In addition, availability of transmission capacity to import power from neighboring markets is limited. For these reasons, the Companies evaluated a case that assumed the Companies had no ability to import power from neighboring markets.

The impact of this change is fairly significant. If the Companies do not have access to neighboring markets during scarcity events, the economic reserve margin is 18% to 18.5%.

5.3 Final Recommendation

The Companies' ability to import power from neighboring markets remains a key uncertainty, considering the declining reserve margins in MISO, PJM, and TVA. With base case inputs, the economic reserve margin is 15.5% to 16.25%. If the Companies cannot import power from neighboring regions, the economic reserve margin is higher, at 18.0% to 18.5%.

At either of these reserve margin levels, the Companies do not meet the 1-in-10 LOLE physical reliability guideline. In the base case, a reserve margin of 21% is needed to meet the 1-in-10 LOLE guideline.

For the 2011 IRP, the Companies utilized a 15% to 17% economic reserve margin range and targeted the midpoint of that range for developing expansion plans. For the 2014 IRP, the Companies will continue to target a minimum reserve margin of 16% for expansion planning. However, there are benefits to customers of maintaining a higher reserve margin to address the uncertainties associated with access to markets, extreme weather events, and unexpected unit performance issues.

COMMONWEALTH OF KENTUCKY

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AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF ITS BASE RATES	)	**2016-00371**

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 7, 2017**

Question No. 23

Responding Witness: John P. Malloy

Q.2-23. The Companies have indicated that they do not plan to replace MV90 meters with AMS. Are there other meters in use for rate schedules TOD-Secondary, TOT-Primary, RTS, or FLS that will not be replaced by AMS. If so, identify, by rate schedule, the number of such meters (other than MV90) that will not be replaced by AMS.

A.2-23. No. The Companies plan on exchanging all of the electric meters excluding the MV-90 billable meters with AMS meters.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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OF ITS ELECTRIC AND GAS BASE RATES	**)**	**2016-00370**

AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-10)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 7, 2017

Question No. 22

Responding Witness: John P. Malloy

Q.2-22. Provide the number of MV90 meters in use, by rate schedule, for the most recent 12-month period available. Also provide the total number of meters (all types) by rate schedule for the same 12-month period.

A.2-22.

Count of MV-90 Billable Meters		
Rate	**KU**	**LGE**
Special Contracts		7
FLS	1	
GS 3Ø	2	9
PS Primary	7	4
PS Secondary	11	76
RTOD E	2	2
RTS	29	21
TOD Primary	280	142
TOD Secondary	669	444
Total	1,001	705

For all non-residential meters, the counts provided are as of September 2016, which are the most recent counts readily available. Residential meter counts are as of February 2017, and should be comparable to the numbers of residential meters in service as of September 2016.

Count of Meters		
Rate	**KU**	**LG&E**
Special Contracts		7
AES 1Ø	341	-
AES 3Ø	265	-
FLS	1	-
GS 1Ø	69,720	30,164
GS 3Ø	19,803	17,383
PS Primary	238	84
PS Secondary	4,722	3,126
RS	440,695	368,764
RTS	31	22
TOD Primary	285	143
TOD Secondary	663	457

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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AND

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-11)

OF

STEPHEN J. BARON

SMART METER RIDER – PHASE 1 **(C)**

A Phase 1 Smart Meter Rider (SMR 1) shall be applied, on a non-bypassable basis, to charges for electricity supplied to customers who receive distribution service from the Company under this Tariff. **(C)**

The SMR 1 shall be computed separately for each of the following three customer classes: **(C)**

(1) Residential: Consisting of Rate Schedules RS and RTS (R),
(2) Small Commercial and Industrial (Small C&I): Consisting Rate Schedules GS-1, GS-3, BL, SA, SM (R), SHS, SLE, SE, TS (R), and GH-2 (R), and
(3) Large Commercial and Industrial (Large C&I): Consisting of Rate Schedules LP-4, LP-5, LPEP, and L5S.

The SMR 1, as computed using the formulae described below, shall be included in the distribution charges of the monthly bill for each customer receiving distribution service from the Company and shall be reconciled on an annual basis for undercollections and overcollections experienced during the previous year. Charges set forth in the applicable rate schedules in this tariff have been adjusted to reflect application of the currently effective SMR 1.

The SMR 1 for the Residential class and the Small C&I class shall be computed using the following formula:

$$\text{SMR 1} = [SM_c / S – E_s / S] \times 1 / (1-T)$$

The SMR 1 for the Large C&I class shall be computed using the following formula:

$$\text{SMR 1} = [SM_c / N – E_s / N] \times 1 / (1-T)$$

Where:

SM_c = An annual budget amount of all costs required for the Company to implement its Commission-approved Smart Meter Plan (SMP) during a compliance year. A compliance year is the 12-month period beginning January 1 of each calendar year and ending December 31 of the same calendar year, except the first compliance year which will also include all smart meter costs incurred prior to January 1, 2011. The annual budget amount is the sum of all direct and indirect capital (e.g., return of and return on applicable smart meter-related investment) and operating (e.g, applicable O&M and taxes) costs, including all deferred design and development costs, and general administrative costs, required to implement the Company's SMP in the compliance year.

The capital and operating costs of each SMP initiative available to only one customer class will be directly assigned to that customer class. The costs of SMP initiatives which cannot be directly assigned to one customer class will be assigned based on the ratio of number of meters assigned to the classes, divided by the number of meters for the entire system.

N = Number of Bills (Customers X 12) per Year

(Continued)

(C) Indicates Change

PPL Electric Utilities Corporation

SMART METER RIDER – PHASE 1 (CONTINUED) **(C)**

Es = Net over or undercollection of the SMR 1 charges as of the end of the 12-month period ending June 30 of each year. Reconciliation of the SMR 1 will be conducted separately for each of the three customer classes based upon the annual EE&C and SMP budgets for each customer class. Interest shall be computed monthly at the legal rate of interest of 6% from the month the over or undercollection occurs to the effective month that the overcollection is refunded or the undercollection is recouped.

S = The Company's total delivered KWH sales to customers in each customer class who receive distribution service under this tariff (including distribution losses), projected for the computation year.

T = The total Pennsylvania gross receipts tax rate in effect during the billing period, expressed in decimal form.

The SMR 1 shall be filed with the Pennsylvania Public Utility Commission (Commission) by August 1 of each year. The SMR 1 charge shall become effective for distribution service provided to all customers on or after the following January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. Upon determination that a customer class's SMR 1, if left unchanged, would result in a material over or undercollection of Smart Meter costs incurred or expected to be incurred during the current 12-month period ending December 31, the Company may file with the Commission for an interim revision of the SMR 1 to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

Minimum bills shall not be reduced by reason of the SMR 1, nor shall charges hereunder be a part of the monthly rate schedule minimum. The SMR 1 shall not be subject to any credits or discounts. The State Tax Adjustment Surcharge (STAS) included in this Tariff is applied to charges under this Rider.

The Company shall file a report of collections under the SMR 1 within thirty (30) days following the conclusion of each computation-year quarter. These reports will be in a form prescribed by the Commission. The third-quarter report shall be accompanied by a preliminary forecast of the SMR 1 for the next computation year.

Application of the SMR 1 shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the SMR 1 and the costs included therein.

(Continued)

SMART METER RIDER – PHASE 1 (CONTINUED) **(C)**

SMART METER RIDER CHARGE **(C)**

Charges under the SMR for the period January 1, 2016 through December 31, 2016, as set forth in the applicable Rate Schedules.

Customer Class	**Large C&I**	**Small C&I**	**Residential**
Rate Schedule / Charge	LP-4, LP-5, LPEP, and L5S $0.00/Bill	GS-1, GS-3, BL, and GH-2 (R) $0.00000/KWH	RS and RTS (R) $0.00000/KWH

Small C&I – Street Lights										
	SA		SM (R)		SHS		SLE		SE	TS (R)
	Nominal Lumens	Charge **(C)**	Nominal Lumens	$/Lamp	Nominal Lumens	$/Lamp	Nominal Lumens	$/Fixture **(C)**	$/KWH	$/Watt
Rate Schedule/ Charge	HPS 9,500	0.000 $/Lamp	3,350	0.000	5,800	0.000	2,600	0.000		
			6,650	0.000	9,500	0.000	3,300	0.000		
			10,500	0.000	16,000	0.000	3,800	0.000	0.00000	0.00000
	LED 4,300	0.000 $/Fixture	20,000	0.000	25,500	0.000	4,900	0.000		
			34,000	0.010	50,000	0.000	7,500	0.000		
			51,000	0.000			15,000	0.000		
							20,000	0.000		

SMART METER RIDER - PHASE 2 **(C)**

A Phase 2 Smart Meter Rider (SMR 2) shall be applied, on a non-bypassable basis, to charges for electricity supplied to customers who receive distribution service from the Company under this Tariff.

The SMR 2 shall be computed separately for each of the following three customer classes:

(1) Residential: Consisting of Rate Schedules RS and RTS (R),
(2) Small Commercial and Industrial (Small C&I): Consisting Rate Schedules GS-1, GS-3, IS-1 (R), BL, and GH-2 (R), and
(3) Large Commercial and Industrial (Large C&I): Consisting of Rate Schedules LP-4, LP-5, LPEP, and L5S.

The SMR 2, as computed using the formulae described below, shall be included in the distribution charges of the monthly bill for each customer receiving distribution service from the Company and shall be reconciled on an annual basis for undercollections and overcollections experienced during the previous year. Charges set forth in the applicable rate schedules in this tariff have been adjusted to reflect application of the currently effective SMR 2.

The SMR 2 for the Residential class, the Small C&I class, and the Large C&I class shall be computed using the following formula:

$$SMR\ 2 = ((SM_c - E_s)\ /\ N\ )\ X\ 1\ /\ (1\text{-}T)$$

Where:

SM_c = A quarterly actual amount of all costs required for the Company to implement its Commission approved Smart Meter Plan (SMP) during a compliance period. The initial SMR 2, effective October 1, 2015, shall be calculated to recover costs not previously reflected in PPL Electric's rates or rate base and that have been recorded on the Company's books and records between February 1, 2015 and August 31, 2015. Thereafter, the SMR 2 will be updated on a quarterly basis to reflect costs during the three-month period ending one month prior to the effective date (a compliance period) of each SMR 2 update. The quarterly amount is the sum of all direct and indirect capital (e.g. return of and return on applicable smart meter-related investment) and operating (e.g., applicable O&M and taxes (dependent upon the Company's tax net operating loss carryforward)) costs, including all deferred design and development costs, and general administrative costs, required to implement the Company's SMP in the compliance period. Deferred costs incurred during 2014 and through May 2015 will be recovered over a three-year period. **(C)**

The costs of SMP will be allocated to the total number of meters on PPL Electric's system based on the ratio of investment in meters for each rate class.

N = Number of Bills (Customers X 3) per Quarter

(Continued)

PPL Electric Utilities Corporation

SMART METER RIDER - PHASE 2 (CONTINUED)

Es = Net over or undercollection of the SMR 2 charges as of the end of the 12-month period ending December 31 of each year. Reconciliation of the SMR 2 will be conducted separately for each of the three customer classes based upon the annual revenue received compared to the actual SMP costs. Interest shall be computed monthly at the residential mortgage lending rate specified by the Secretary of Banking in accordance with Loan Interest and Protection Law (41 P.S. §§ 101, *et. seq.*) from the month the over or undercollection occurs to the effective month that the overcollection is refunded or the undercollection is recouped.

T = The total Pennsylvania gross receipts tax rate in effect during the billing period, expressed in decimal form.

The SMR 2 shall be filed with the Pennsylvania Public Utility Commission (Commission) and served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Auditing, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update. The changes in the SMR 2 rate will occur as follows:

(C)

Effective Date of Change	Date to which SMR 2 - Eligible Costs Reflected
October 1, 2016	June 1 – August 31, 2016
January 1, 2017	September 1 – November 30, 2016
April 1, 2017	December 1, 2016 – February 28, 2017
July 1, 2017	March 1 – May 31, 2017

Minimum bills shall not be reduced by reason of the SMR 2, nor shall charges hereunder be a part of the monthly rate schedule minimum. The SMR 2 shall not be subject to any credits or discounts. The State Tax Adjustment Surcharge (STAS) included in this Tariff is applied to charges under this Rider.

The Company shall file a report of collections under the SMR 2 within thirty (30) days following the conclusion of each computation-year quarter. These reports will be in a form prescribed by the Commission.

Application of the SMR 2 shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the SMR 2 and the costs included therein.

(Continued)

PPL Electric Utilities Corporation

SMART METER RIDER - PHASE 2 (CONTINUED)

SMART METER RIDER - PHASE 2 CHARGES

Charges under the SMR 2 for the period January 1, 2017 through March 31, 2017, as set forth **(C)** in the applicable Rate Schedules.

Customer Class	Large C&I	Small C&I	Residential
Rate Schedule / Charge	LP-4, LP-5, LPEP, and L5S $46.80/Bill **(I)**	GS-1, GS-3, BL, and GH-2 (R) $2.13/Bill **(I)**	RS and RTS (R) $1.08/Bill **(I)**

(I) Indicates Increase **(D)** Indicates Decrease **(C)** Indicates Change

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS BASE RATES	**)**	**2016-00371**

EXHIBIT__(SJB-12)

OF

STEPHEN J. BARON

OHIO POWER COMPANY

4th Revised Sheet No. 484-1
Cancels 3rd Revised Sheet No. 484-1

P.U.C.O. NO. 20

gridSMART PHASE 1 RIDER

Effective with the first billing cycle of June 2015 all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the monthly gridSMART charge. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Residential Customers	$ 1.01/month
Non-Residential Customers	$ 4.22/month

Filed pursuant to Order dated May 28, 2015 in Case No. 14-192-EL-RDR

Issued: June 1, 2015

Effective Cycle 1 June 2015

Issued by
Pablo Vegas, President
AEP Ohio

OHIO POWER COMPANY Original Sheet No. 485-1

P.U.C.O. NO. 20

gridSMART PHASE 2 RIDER

Effective June 1, 2015, all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the monthly gridSMART Phase 2 charge of $0.00.