COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March, 2015

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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 thirty 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, 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 and who are participating in this proceeding are: AAK, USA K2, LLC, Carbide Industries LLC, Cemex, Clopay Plastic Products Co., Inc., Corning Incorporated, Dow Corning Corporation, E.I duPont de Nemours and Company, Lexmark International, Inc., MeadWestvaco, North American Stainless, Toyota Motor Manufacturing, Kentucky, Inc., and Verso Corporation.

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

A. Yes. I have testified in 16 KU and LG&E cases since 1981.

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 raised by the Company's filings in this case. The first issue that I address concerns the Company's filed cost of service study using the base-intermediate-peak ("BIP") class cost of service methodology. 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. In particular, the BIP method tends to allocate an inappropriately large percentage of the Companies' production and transmission costs to high load factor industrial rate classes because a significant portion of these production and transmission costs are classified as energy related (the base portion of the BIP method). Notwithstanding this general objection to the BIP method, I have identified an error in both of the Companies' BIP studies related to the development of individual rate class demand allocation factors. Specifically, the Companies did not adjust metered hourly loads for losses in the development of the demand allocation factors. There is an additional error in the LG&E cost of service study associated with the RTS rate class. LG&E has improperly allocated distribution plant and expenses to this transmission voltage rate class; because these customers take service from the transmission system, there should be no allocation of distribution facilities to the RTS class. I have corrected these errors and present corrected BIP studies for both Companies in my testimony.

In addition to a corrected BIP study, I believe that it is important for the Commission to consider alternative class cost of service methodologies. I have developed two alternative class cost of service studies for each of the Companies. These studies, a 5 highest coincident peak ("CP") methodology based on the approach used by PJM Interconnection, Inc. ("PJM") and a 12 CP methodology, each allocate production and transmission demand related costs using alternative approaches to the BIP method. Based on the results of the corrected BIP, PJM 5 CP and 12 CP cost of service studies, and in recognition that other factors such as economic development, job retention, job growth and gradualism should to be considered when setting rates, I recommend that the Commission adopt the Companies' proposed uniform percentage increases to each rate class in this case.

I will also address the Companies' proposed revisions to their Curtailable Service Riders (CSR10 and CSR30). I explain why the Companies proposed changes are not reasonable and recommend continuation of the current CSR tariffs, with two modifications. LG&E and KU are proposing to maintain the credit provided to curtailable customers at the current levels. I will recommend that the CSR10 and CSR30 credits be increased to reflect the level of avoided capacity cost used by the Companies' to evaluate the economic reasonableness of their Demand Side Management ("DSM") programs. This credit level also is consistent with other measures of avoided cost based on the cost of a new simple cycle combustion turbine unit. Although I oppose the majority of the Companies' proposed CSR tariff changes, I support the proposal that requires an annual certification by CSR customers of their ability to actually interrupt the CSR load. All other provisions of the current CSR tariffs should be maintained.

I also discuss LG&E's proposal in this case, to merge its Industrial Time-of-Day Primary ("ITODP") and Commercial Time-of-Day Primary ("CTODP") rate schedules. While conceptually I do not oppose such a merger, the proposed merged rate produces an unreasonable level of disparate impact on current ITODP customers and CTODP customers (CTODP customers will receive a 4.5% rate decrease, ITODP customers will receive a 4.5% increase, if the rates are merged). I will recommend continuing with two separate rate schedules, but provide for a 1% higher increase for ITOD customers, on average, than for CTOD customers. This will bring the two rates together more gradually and permit a merger in a future base rate case (subject to an examination of the impacts at that time).

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **The BIP cost of service studies presented by the Companies in this case should be corrected to reflect losses in the calculation of rate class demand allocation factors. The Companies' class cost of service studies appear to have inadvertently omitted this important step in the development of demand allocation factors. The LG&E BIP study should also be corrected to eliminate distribution costs that were incorrectly allocated to LG&E's RTS rate class. The Commission should not rely on the Companies' studies because of these errors. KIUC is presenting corrected BIP class cost of service studies.**

- **The Commission should consider a range of alternative cost of service studies using the PJM 5 CP and 12 CP methodologies, as well as the corrected BIP method to apportion the approved revenue increase for each Company. Based on the KIUC sponsored studies, and in consideration of economic development and gradualism, I recommend that the Companies' proposed uniform percentage increases each rate class be adopted.**

- **The Companies' proposal to modify the CSR10 and CSR30 tariffs should be rejected. The elimination of the buy-through provision and the change to permit the shut-down of CSR customer operations for any reason (as opposed to only system reliability events) are not reasonable.**

  The current versions of these tariffs should be maintained, with two modifications: 1) the CSR10 and CRS30 credits for transmission service paid to customers taking service under these tariffs should be increased from the current level of $5.40/kVa-month and $4.30/kVa-month to

$8.33/kVa-month and $6.63/kVa-month. This would align these CSR credits with the avoided capacity cost used by the Companies in developing their DSM programs. These increased credits are also consistent with avoided capacity cost based on PJM's NET CONE (cost of new entry) calculation and the Department of Energy's Energy Information Administration calculation of the cost of a new simple cycle combustion turbine.

In addition, the Companies' proposed modification to the CSR tariffs to require that customers annually certify their ability to interrupt CSR load pursuant to the requirements of the tariff should be accepted.

- **LG&E' proposed merger of rates CTODP and ITODP should be rejected due to the significant differences in the percentage increases to existing customers on these two rates that will occur under LG&E's merged rate. Rather, rate CTODP should receive a 1% lower rate increase than rate ITODP in this case. Subject to a review of the impacts, the CTODP and ITODP rates can then be merged in future LG&E base rate cases.**

II. CLASS COST OF SERVICE ISSUES

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

A. Yes. The BIP method is the class cost allocation method used by both Companies in prior cases.

The basic methodology, as discussed by Company witness Dr. Martin Blake, first functionalizes the Company's production and transmission 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 and transmission demand-related costs are assigned as follows:

	Assignment of Total P&T Costs
Base	**34.99%**
Winter Peak	**34.10%**
Summer Peak	**30.91%**

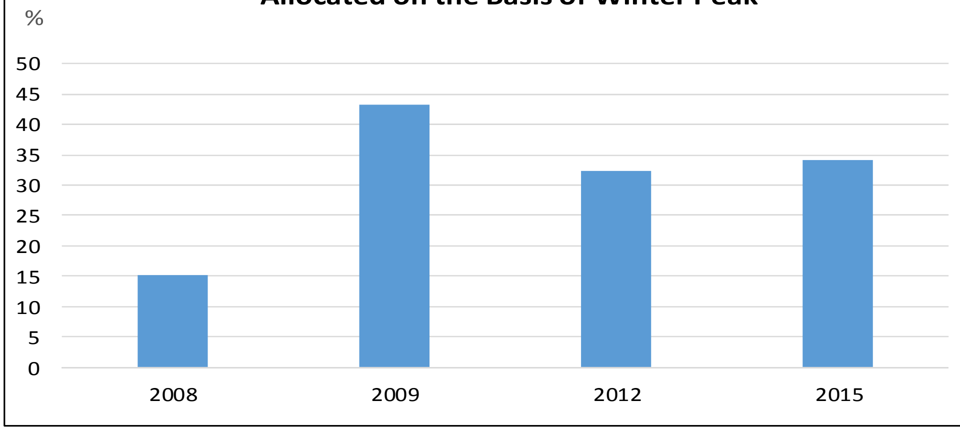
These functional allocators for the base, intermediate and peak periods are identical for both LG&E and KU under the Companies' methodology. Once the total production and transmission demand-related costs have been functionalized to these three categories, they are allocated to rate classes using three different class allocation factors. For the 34.99% of production and transmission 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 30.91% of all production and transmission 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 34.10% of the Company's total production and transmission 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. First, 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 the 2008 study, only 15.32% of the system production and transmission 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 and transmission 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 are approximately equal - 33.26 summer, 32.39 winter). In this current 2015 case, the summer period once again is assigned the least amount of cost responsibility. Figure 1 summarizes the changes from year to year in the amount of production demand costs that are allocated to rate classes on the basis of winter perk demands using the Companies' BIP methodology.

Figure 1
BIP Percent of Production Demand Costs
Allocated on the Basis of Winter Peak



These dramatic changes in the BIP percentages 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. In particular, given the Companies current IRP projections that the summer system peak will continue to substantially exceed the winter peak, the BIP allocation certainly raises questions regarding the reasonableness of the method to reflect cost causation.

Q. **Have you identified any specific errors in the Companies' BIP class cost of service studies?**

A. Yes. A review of the Companies' workpapers supporting the development of class demand allocation factors from hourly loads indicates that the Companies have not adjusted the class demands at the meter for losses. While the Companies have properly adjusted energy at the meter for losses, no such adjustment was made to demands. Specifically, the Companies' demand allocation factors only reflected demands at the meter. These demands at the meter should have been adjusted to include losses. Table 1 below shows the corrected BIP demand allocation factors, compared to the Companies' calculation, for both LG&E and KU.

Table 1
Corrected BIP Allocation Factors

	LG&E		KU	
	As-Filed	**Corrected**	**As-Filed**	**Corrected**
RS	0.44958	0.45105	0.42177	0.42432
GS	0.11108	0.11139	0.09787	0.09839
AES			0.00842	0.00847
PS-Sec	0.14581	0.14620	0.10147	0.10199
PS-Pri	0.01163	0.01153	0.01273	0.01262
TOD-Sec	0.07348	0.07367	0.07084	0.07118
TOD-Pri	0.13360	0.13249	0.18649	0.18501
RTS	0.05156	0.05047	0.07023	0.06837
FLS			0.02240	0.02185

Similar adjustments to reflect losses were also made to the NCP demand allocation factors.

In addition, I also identified an error in the LG&E BIP cost of service study associated with an improper allocation of distribution plant and expenses to the RTS class. Rate RTS serves customers at the transmission voltage level who do not rely on or utilize the Company's distribution system. This appears to be an inadvertent error in the Company's study; no distribution plant allocation was made to the RTS class in the KU cost of service study nor in the 2012 LG&E cost study.

Q. Have you corrected the KU and LG&E BIP cost of service studies to fix this problem?

A. Yes. Baron Exhibits__(SJB-2) and (SJB-3) show a summary of the corrected BIP cost of service studies. Table 2 below summarizes the corrected rates of return for LG&E and KU. Also shown are the Companies' results.

Table 2
LG&E -KU Class Cost of Service Summay
Summary of Corrected Rates of Return by Class

	LG&E		KU	
	As-Filed BIP	KIUC Corrected BIP	As-Filed BIP	KIUC Corrected BIP
Residential	3.87%	3.79%	2.77%	2.74%
General Service	12.06%	11.89%	9.01%	8.95%
All Electric Schools			4.43%	4.38%
Power Service Sec	11.51%	11.34%	11.29%	11.21%
Power Service Pri	8.76%	8.77%	8.24%	8.38%
TOD Secondary	8.54%	8.40%	5.42%	5.37%
TOD Primary Lines	6.26%	6.26%	3.34%	3.42%
Retail Transmission Service	2.25%	4.07%	3.41%	3.65%
Fluctuating Load Service			1.53%	1.71%
Lighting	4.26%	4.24%	2.75%	2.74%
Special Contracts	1.35%	1.35%		
Total System	6.18%	6.18%	4.55%	4.55%

As can be seen, the largest impact of this correction is for KU's and LG&E' large power rates (RTS and FLS) that are high voltage rate schedules.

Q. In addition to correcting the Companies' BIP cost of service studies, have you also developed any alternative class cost of service studies using other production and transmission demand allocation methodologies?

A. Yes. In order to develop a better understanding of the cost to serve each of LG&E's and KU's rate classes, I also present a two alternative cost of service studies based on the 5 highest coincident peak method (PJM 5 CP) and the 12 CP method. The purpose of these presentations is to present cost of service results for each rate class under a variety of traditional cost of service studies, and the implications of such alternative methods on the Companies' proposals for rate class revenue apportionment in this case.[1]

Q. Would you please describe the additional studies that you have developed to assess the contributions of each customer class to the Company's overall cost of service

A. Yes. Baron Exhibits **____**(SJB-4) and (SJB-5) contain summary results of the two alternative cost of service studies for KU. Each of these studies incorporates the corrected BIP demand allocation factors. The first alternate cost of service study utilizes a variant of the 5 CP cost allocation methodology, which I am referring to as the PJM 5 CP method. The traditional 5 CP method allocates production and transmission demand costs on rate class contributions to the 5 highest monthly

[1] For example, Kentucky Power Company and Big Rivers Electric Corporation use a 12 CP methodology and East Kentucky Power Cooperative uses a 6 CP methodology.

system peaks. The PJM 5 CP method allocates these demand related costs on rate class contributions to the 5 highest system peaks, regardless of when they occur. This methodology is used by PJM to assign capacity obligations to load serving entities within a load zone and is thus being used by a significant number of utilities.[2] PJM uses this methodology to assign generation capacity obligations within load zones (such as AEP, Duke Energy and East Kentucky).

The second alternative cost of service study that I developed uses a traditional 12 CP production/transmission demand allocation methodology. The Commission recently adopted the 12 CP method for Big Rivers Electric Cooperative and Kentucky Power Company has traditionally used the 12 CP method for retail cost of service studies in Kentucky.

Q. What do the studies show with regard to the rate of return paid by each rate class on the KU system?

A. Table 3 summarizes the rates of return for each rate class produced by each alternative cost of service study, the corrected BIP study and the Company's filed BIP cost study. Also shown is a simple average of these results (excluding the Company's filed study) across all studies and a relative rate of return index.

[2] Kentucky Power Company, an AEP subsidiary is a member of PJM and East Kentucky Power Cooperative is proposed to be a PJM member.

Table 3
Kentucky Utilities Company
Comparison of Corrected BIP and Alternative Class Cost of Service Studies

	KU BIP As-Filed	Corrected BIP	12 CP	PJM 5 CP	Average*	Index
Residential	2.77%	2.74%	2.73%	2.76%	2.74%	0.60
General Service	9.01%	8.95%	8.31%	7.89%	8.38%	1.84
All Electric Schools	4.43%	4.38%	3.35%	4.26%	3.99%	0.88
Power Service Sec	11.29%	11.21%	11.06%	10.01%	10.76%	2.36
Power Service Pri	8.24%	8.38%	7.26%	6.79%	7.48%	1.64
TOD Secondary	5.42%	5.37%	5.65%	5.02%	5.35%	1.17
TOD Primary Lines	3.34%	3.42%	3.45%	3.57%	3.48%	0.76
Retail Transmission Service	3.41%	3.65%	3.67%	4.19%	3.84%	0.84
Fluctuating Load Service	1.53%	1.71%	2.81%	7.30%	3.94%	0.86
Lighting	2.75%	2.74%	4.06%	4.70%	3.84%	0.84
Total System	4.55%	4.55%	4.55%	4.55%	4.55%	1.00

* Average of Corrected BIP, 12 CP and PJM 5 CP

As can be seen from each of the exhibits summarizing the studies evaluated, the residential class pays substantially below the average system rate of return, regardless of the cost of service methodology. Under each of these methods, the residential class covers its cost of service expenses and provides only a small portion of its share of KU's return. Even under the Company's BIP method, which generally favors low load factor classes such as the residential class because of its use of an energy allocator for a substantial part of the fixed generation and transmission costs, the Company's residential class is only paying a rate of return on investment of 2.74%, compared to the system average rate of return of 4.55%.

Q. Have you prepared similar analyses for LG&E?

A. Yes. Baron Exhibits ____(SJB-6) and (SJB-7) contain cost of service study results for LG&E reflecting the same two alternative.

Q. How do the alternative cost of service study results compare to the corrected BIP analysis?

A. Table 4 summarizes the results of each of the cost of service studies that I developed for LG&E, compared to the Company's BIP study and the corrected BIP analysis that I previously discussed. As can be seen, the average rate of return index for the residential class is 0.59, which means that the residential class is only paying a rate of return on investment at half the rate of the average customer (the Special Contract class is also at a very low rate of return). All other rate classes, except lighting, are above the system rate of return, some significantly above.

Table 4
Louisville Gas and Electric Company
Comparison of Corrected BIP and Alternative Class Cost of Service Studies

	LGE BIP As-Filed	Corrected BIP	12 CP	PJM 5 CP	Average*	Index
Residential	3.87%	3.79%	3.72%	3.33%	3.61%	0.58
General Service	12.06%	11.89%	10.92%	10.79%	11.20%	1.81
Power Service Sec	11.51%	11.34%	11.04%	11.70%	11.36%	1.84
Power Service Pri	8.76%	8.77%	8.54%	9.10%	8.80%	1.42
TOD Secondary	8.54%	8.40%	8.23%	8.86%	8.50%	1.37
TOD Primary Lines	6.26%	6.26%	6.65%	7.51%	6.80%	1.10
Retail Transmission Service	2.25%	4.07%	5.73%	10.07%	6.62%	1.07
Lighting	4.26%	4.24%	5.38%	6.26%	5.29%	0.86
Special Contracts	1.35%	1.35%	1.92%	2.49%	1.92%	0.31
Total System	6.18%	6.18%	6.18%	6.18%	6.18%	1.00

* Average of Corrected BIP, 12 CP and PJM 5 CP

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. As discussed in Dr. Blake's testimony, both KU and LG&E are proposing uniform percentage increases for each rate class. Tables 5 and 6 below summarize the LG&E and KU rate class revenue increases proposed by the Companies in this case.

Table 5
Louisville Gas and Electric
Proposed Revenue Increases

	Adjusted Revenues	Increase	Percentage Increase
Residential Rate - RS	436,058,181	11,911,869	2.73%
General Service Rate - GS	154,856,602	4,213,025	2.72%
Power Service Rate	193,437,886	5,269,319	2.72%
Time of Day Secondary Service TODS	86,270,519	2,347,732	2.72%
Time of Day Primary Service TODP	153,205,443	4,187,361	2.73%
Retail Transmission Service -- RTS	55,631,555	1,520,807	2.73%
Special Contracts	10,889,812	297,742	2.73%
Curtailable Service Riders	(3,438,312)	-	0.00%
Traffic Energy Service	300,152	8,176	2.72%
Total Lighting Service	19,247,170	524,781	2.73%
TOTAL ULTIMATE CONSUMERS	1,106,459,008	30,280,812	2.74%
Other Revenues	15,170,599	-	0.00%
TOTAL JURISDICTIONAL	1,121,629,607	30,280,812	2.70%

Table 6
Kentucky Utilities
Proposed Revenue Increases

	Adjusted Revenues	Increase	Percentage Increase
Residential Rate - RS	593,998,244	56,839,411	9.57%
General Service Rate - GS	216,871,822	20,741,924	9.56%
All Electric Schools	12,936,297	1,238,148	9.57%
Power Service Rate	219,786,208	21,023,825	9.57%
Time of Day Secondary Service TODS	118,607,258	11,341,999	9.56%
Time of Day Primary Service TODP	284,176,010	27,203,590	9.57%
Retail Transmission Service -- RTS	99,821,566	9,554,633	9.57%
Fluctuating Load Service - FLS	31,466,313	3,010,052	9.57%
Curtailable Service Riders	(11,877,948)	-	0.00%
Traffic Energy Service	138,147	13,216	
Total Lighting Service	25,830,100	2,475,884	9.59%
TOTAL ULTIMATE CONSUMERS	1,591,754,017	153,442,682	9.64%
Other Revenues	25,555,228	-	0.00%
TOTAL JURISDICTIONAL	1,617,309,245	153,442,682	9.49%

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

A. Yes. Based on the results of the alternative class cost of service studies, including the corrected BIP studies, I believe that the Companies' revenue increase proposals should be adopted. As Dr. Blake explains, the Companies' revenue increase apportionment proposal is consistent with gradualism, while moving class rates of return towards cost of service.

Q. Are there other factors that the Commission should consider in deciding the appropriate revenue increases for each rate class?

A. Yes. The Commission should consider the overall impact on large industrial customers, particularly manufacturing customers on the State's economic development. The Companies' proposed uniform percentage increases for LG&E and KU provide some mitigation of the impact of the Companies' requested revenue increases to 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. This is in contrast to large industrial manufacturing customers that face national and international competition. This is consistent with 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. The testimony of KIUC witness Dr. Paul Coombs provides additional information regarding this issue.

Q. KIUC is recommending adjustments to each of the Company's overall revenue increases in these cases. In the event that the Commission adopts KIUC's

position and orders adjustments to each of the Company's requested increases, do you have a recommended allocation of the approved increases?

A. Yes. For the reasons I discussed above, I recommend that any Commission approved revenue increase be allocated on a uniform basis to each rate schedule, for each Company.

IV. CURTAILABLE SERVICE RIDER ISSUES

Q. Would you please discuss the Companies' proposed changes to the Curtailable Service Riders ("CSR")?

A. As discussed in the testimony of Companies' witness David Sinclair, the Companies are proposing to modify their CSR tariffs in this case. The CSR tariffs provide the terms and conditions applicable to customers participating in the Companies' interruptible load program. There are two alternative CSR tariffs, CSR10 and CSR30. These tariffs differ in the notice period provided to participating customers for interruptions; CSR10 requires only a 10 minute notice, CSR30 requires a 30 minute notice. In exchange for a customer's agreement to be interrupted, the customer receives a credit (CSR credit). The credit is designed to compensate the customer for taking non-firm service and generally reflects the avoided cost of generating capacity that the Companies would otherwise have to procure (buy, build, etc.) without the customer's agreement to interrupt its CSR load during emergency events on the KU and LG&E systems. The Companies reflect this CSR interruptible load as a capacity resource in the KU/LG&E IRP.

Q. What changes are the Companies' proposing to the CSR tariffs?

A. KU and LG&E are proposing 4 changes to the current CSR tariffs. The current tariff permits up to 375 hours of curtailment. Of that amount, 275 hours can be interrupted at the sole discretion of the Companies, but the CSR customer has the option to buy-through the curtailment and pay an energy price pursuant to a formula tied to market natural gas prices. The remaining 100 hours of interruption can only occur during "system reliability events." These system reliability event interruptions (e.g. emergencies) cannot be bought-through. The Companies are proposing in this case to eliminate the buy-through option, but reduce the maximum hours of interruption to 100 hours.

Q. Would the 100 hours of potential interruption be subject to a system reliability event?

A. No. This is a very significant change in the CSR tariff. Under the proposed CSR tariff, the Companies could interrupt a CSR customer for up to 100 hours, at the sole discretion of the Companies – meaning for any reason or for no reason. There would no longer be a requirement for a system reliability event to occur ("Limitation on curtailment request – None").[3] Since the buy-through option is also being eliminated, this means that a customer would likely face 100 hours of shut-down of its manufacturing operations, without the opportunity to buy-through, whenever the Companies deem that such an interruption should occur. Moreover, since under the proposed tariff (and the current tariff, as well), interruptions can be for as little as 30 minutes, a CSR customer could be subject to up to 200 days of shut down without any opportunity to buy-through the interruption, regardless of whether or not energy is available. This is a punitive proposal that will significantly degrade the quality of service under the CSR tariff and unnecessarily reduce the competitiveness of participating customers.

Q. Would you explain why this is a punitive proposal?

A. The current CSR tariff, while permitting up to 375 hours of interruptions, allows customers to buy-through 275 hours of such potential interruptions. Only in the event of a true system emergency, would a customer be required to shut down its manufacturing operations. This means that CSR customers, if they are willing to pay the "Automatic Buy-Through Price" would only be subject to 100 hours of physical interruption, and then only during a system reliability event. The Companies new proposal is punitive because even if there are no system emergencies, and power is available, a CSR customer would have to shut down its

[3] Sinclair direct testimony, Table 6.

production facilities. As explained by North American Stainless witness Mary Jean Riley, there are significant costs associated with each shut down of manufacturing operations. It is simply irrational to prohibit an interruptible customer, who is willing to curtail significant amounts of capacity during emergency situations, to also curtail when power is available and the customer is willing to pay the Automatic Buy-Through rate. The customer should be permitted to make the economic calculation of whether or not to buy-through the interruption based on its own economics, if power is available (i.e., there is not a system reliability event). This is in contrast to the current CSR tariff that only requires physical interruption in true system reliability emergencies. This is the intended basis for an interruptible rate such as the CSR tariffs.

Q. Is it your understanding that the Companies' intend to interrupt CSR customers, within the 100 hour limitation, to reduce fuel expenses, in addition to providing system reliability?

A. Yes. In response to KIUC Question No. 1-55, LG&E stated: "The Companies will attempt to optimize the utilization of the 100 hours to address system conditions and reduce system fuel and purchase power costs." [Baron Exhibit__(SJB-8) contains a copy of this response.]

While CSR customers receive a credit based on the value to the Companies of interruptible load as a capacity resource, the Companies are clearly intending to use their new unlimited ability to interrupt CSR customers in order to avoid fuel and purchase energy costs.[4] Even though not stated in the data response, the Companies could also use the ability to shut down CSR customers for 100 hours per year in order to make additional off-system sales, the profits of which are retained by utility shareholders in between base rate cases. CSR customers are not being compensated for this "energy" value.

I should note that in the PJM Demand Response program, PJM separates the payments to demand response customers into emergency program payments (which are reliability related), and energy payments (Economic program) that are determined by the value of avoided energy costs based on hourly Locational Marginal Prices ("LMP"). These are two separate attributes of demand response and participating customers receive separate payments for each demand response product that is offered and accepted by PJM.

The Companies' proposed modifications to the CSR tariffs represent a bad public policy that would potentially hurt economic activity (and jobs) in Kentucky. My recommendation is to maintain the current 375 hours of interruption; 275 hours with a buy-through option that provides the Companies with flexibility to interrupt at their sole discretion and 100 hours of physical interruption, without a buy-through

[4] In response to KIUC Question No. 1-58 to LG&E (attached as Baron Exhibit__(SJB-9), the Companies state that: "The Companies' practice of modeling CSR is to use it as a resource to meet load obligations."

option pursuant to a system reliability event. The Commission should continue the current CSR tariff provisions, subject to two recommended changes that I will discuss next.

Q. Would you discuss the first modification that you propose to the current CSR tariffs?

A. The first change that I recommend is to increase the CSR10 and CSR30 credits to reflect avoided capacity costs of the Companies. The current CSR10 credit, paid to participating customers (transmission voltage) based on the ability of the Companies' to use CSR interruptible load as a capacity resource, is $5.40/kVa-month (the CSR30 credit is $4.30/kVa-month for transmission voltage customers, reflecting a lower amount in recognition of the 30 minute notice requirement). As I discussed above, the Companies treat CSR load as a peaking capacity resource. This is confirmed by Companies' witness David Sinclair at page 27 of his Direct Testimony in this case. These credits are substantially below the avoided cost of capacity used by the Companies to screen DSM measures and programs for cost-effectiveness.

Q. What is the System avoided capacity cost level used by the Companies in their DSM program cost effectiveness analyses?

A. In its response to Sierra Club's Initial Data Requests Dated January 8, 2015, Question No 10(d), KU states as follows: "System avoided capacity cost are [sic]

$100/kW-yr." This response is attached as Baron Exhibit__(SJB-10). A $100/kW-year avoided capacity cost is equivalent to an $8.33/kVa-month credit. In its response to Question No. 21 of the Attorney General's Initial Data Requests in the 2014 IRP case (Case No. 2014-00003), LG&E stated as follows: "For example, any energy-efficiency measure incentive is capped at the Companies' avoided cost of capacity ($100/kW-year), as it would be otherwise more economical to serve energy from supply-side resources." [Baron Exhibit__(SJB-11) contains a copy of this data response.]. For its DSM programs, the Companies' use a capacity value of $8.33/kVa-month, which is almost $3.00/kVa-month greater than the CSR10 transmission voltage credit of $5.40/kVa-month.

Q. How does the Companies' $8.33/kVa-month avoided capacity cost compare to other measures of avoided capacity cost?

A. I have reviewed three alternative measures of avoided capacity cost. The first is based on the Companies' cost of a new simple cycle combustion turbine ("SSCT"). Baron Exhibit__(SJB-12) is a copy of page 15 of the 2014 Reserve Margin study included in Volume III of the Companies' 2014 Integrated Resource Plan. Based on the Companies' current planning assumptions, the 2018 annual capacity cost of a SCCT is $88.2/kW-year. Discounting this value back to 2016 and applying a 16% reserve margin adjustment produces an annual value of $98.73/kW-year or $8.23/kW-month.

Q. Why did you increase the cost by 16% to reflect the Companies' 16% planning reserve margin?

A. This reserve margin adjusted cost reflects the cost that would be incurred by the Companies, and thus all of their customers, if 1 kW of load were considered firm, instead of interruptible (CSR). In effect, if the customer did not agree to be interruptible, then the Companies would have to plan for 1.16 kW of capacity (1 kW plus 16% reserves). Thus, by agreeing to curtailment, the 1 kW of load that would otherwise would be on at the peak, the Companies will avoided about $8.23 (the cost of owning a new SSCT plus associated reserves). In the case of one of KU's CSR10 customers that takes service on Rate FLS, this might mean that the Companies could avoid capacity for 185 mW that might otherwise be on during the peak.[5] The point is, the benefit to the KU/LG&E system is the ability to avoid that potential increase in capacity resources – this is due to the availability of the CSR10 tariff. It is reasonable to reflect the full avoided capacity cost in the CSR credit to participating customers.

Q. Do you have other examples of avoided capacity cost that provides support for setting the CSR10 credit to the Companies' avoided capacity cost rate of $8.33/kVa-month?

[5] Based on KU's response to KIUC Question No. 1-53, the maximum forecasted FLS hourly load during the period 2015 to 2016 is about 185 kVa. The data response is attached as Baron Exhibit__(SJB-13).

A. Yes. PJM calculates a number of inputs that are used each year in its Reliability Planning Model ("RPM") Base Residual Auction ("BRA"). The PJM BRA, which is held in May of each year, is used by PJM to acquire capacity from market participants to meet the reliability needs of PJM 3 years into the future. The most recent PJM BRA was held in May 2014 and was used to acquire capacity for PJM's 2017/2018 Planning Year. Among the inputs used by PJM to establish the parameters of the BRA is an estimate of Net CONE. Net CONE is the net cost of new entry and is calculated as the levelized cost of a new simple cycle combustion turbine, net of revenues that can be achieved through sales of ancillary services and energy into the PJM market. It is thus a measure of the "pure" cost of providing reliability or capacity. The RPM Net CONE value calculated by PJM for use in the 2017/2018 BRA was $352.63/MW-day in PJM CONE Area 3, which includes AEP and Duke Energy. The $352.63/MW-day value translates into a monthly capacity rate of $10.73/KW. Baron Exhibit__(SJB-14) contains the planning parameters used for the 2017/2018 BRA.

The second example is based on an analysis developed by the U.S. Energy Information Administration ("EIA"). As part of its Annual Energy Outlook each year, EIA develops cost estimates for various types of generating units. Baron Exhibit__(SJB-15) contains a copy of the EIA report "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014," prepared April 2014. Page 6 of this report shows cost data for a conventional combustion turbine unit (SSCT). Using this data, I developed an equivalent $/kW – month estimate of the cost of a new combustion turbine in 2016, the test year in this case. Table 7 below presents the results of the calculation, which produces an avoided capacity rate of $10.11/kW-month, before adding 16% reserves.

Table 7
2014 Energy Information Administration - AEO2014
Levelized SSCT Cost

Levelized Capital Cost (2012$/mWh)	40.20
Fixed O&M (2012$/mWh)	2.80
Total Levelized Fixed Cost (2012 $/mWh)	43.00
Annual Escalation Rate	1.80%
Total Levelized Fixed Cost (2016 $/mWh)	46.18
Annual Capacity Factor	30.00%
Levelized Annual Cost of CT Capacity $/kW-Year - 2016	121.36
Levelized Annual Cost of CT Capacity $/kW-Month - 2016	10.11

Q. What do you conclude from these multiple sources of avoided capacity cost data?

A. Both the PJM Net CONE and the EIA avoided capacity cost data confirm that the Companies' $8.33/kVa-month avoided capacity cost measurement is reasonable and is an appropriate measure of the value of CSR load.

Q. Why is it appropriate to set the CSR credits at a long-term avoided capacity cost rate, rather than short term market rates that might be lower?

A. The Companies consider CSR interruptible load as a capacity resource. This is clear from both the Companies' response to KIUC 1-58 (LG&E) shown in Baron Exhibit__(SJB-9) and the Companies' 2014 IRP, in which CSR load is treated as a capacity resource in a manner consistent with all of the Companies' supply side generation resources. Because CSR load is considered (and correctly so) a resource available to the Companies to meet load obligations over time, it is a long-term resource. The IRP projects CSR capacity for many years. As Companies' witness Sinclair states on page 27 of his testimony, CSR is a substitute for CT capacity that the Companies would otherwise have to obtain to meet its load obligations. Because CSR load substitutes for capacity, the CSR credit should reflect long term avoided capacity cost, not short-term market prices. It is not reasonable to price CSR credits based on short-term market prices, while supply-side capacity acquisitions over time reflect the cost of new construction. CSR load has existed on the Companies' systems for many years. It is no more reasonable to re-price CSR credits at short-term market prices than it would be to re-price an LG&E or KU CT each year based on market-prices.

Q. Is this consistent with the method used by the Companies' to evaluate DSM projects for cost effectiveness?

A. Yes. The Companies use long-term avoided capacity costs ($100/kW-year) to make their cost-effectiveness evaluations of DSM projects. CSR load credits should reflect the same framework. Long-term avoided capacity costs are the appropriate basis for developing the CSR10 and CSR30 credits.

Q. Are there other reasons to utilize long-term avoided capacity costs as the basis for the CSR credits?

A. Yes. First, CSR customers incur costs to participate in the CSR program. This might include both actual investments and also may include production design arrangements that are geared around the ability to interrupt. To the extent that a customer operates its production facilities in anticipation of possible interruptions in a manner less efficient than it would be, absent the risk of interruption, this is a cost that a CSR customer incurs in exchange for the CSR credit. If the CSR credit was set at short-term market capacity prices, the risk of participating in the CSR program would likely increase.

Q. What is your recommendation regarding the appropriate CSR10 and CSR30 monthly credits?

A. I recommend that the CSR10 credit be set at $8.33/kVa-month, the Companies' avoided capacity cost. Following the current practice, the CSR30 credit should be set at 80% of this amount, or $6.63/kVa-month. For primary voltage service, the respective CSR10 and CSR30 credits would be $8.43/kVa-month and $6.73/kVa-month

Q. Please discuss the second change to the CSR tariffs that you are recommending?

A. The second change to the current CSR tariffs is the Companies' proposal to require annual certification of a CSR customer's ability to actually physically interrupt its load. This is a reasonable requirement and should be adopted by the Commission.

V. RATE DESIGN ISSUES

Q. Do you have any concerns regarding LG&E's proposal to merge its Commercial Time of Day Primary ("CTODP") and Industrial Time of Day Primary ("TODP") rates in this case?

A. Yes. As in its last base rate case, LG&E is proposing to merge rate schedules CTODP and ITODP. While I do not oppose this merger conceptually, I do oppose LG&E's specific proposal to merge these two rates in this case because of the very large, disparate rate increases that the Company is proposing for CTODP and ITODP customers. Table 8 below shows the proof of revenue calculations for the CTODP and ITODP rates. Based on LG&E witness Dr. Blake's proposal to uniformly increase each rate class by the same uniform percentage, the merged CTODP/ITODP rate will receive a base rate increase of 2.73%, the same as the LG&E retail average increase.

Table 8
Time-of-Day Primary
LG&E Proposed Revenue Increases

	Present Rates	Proposed Rates	Present Revenues	Proposed Revenues	% Change
COMMERCIAL					
Basic Service Charges	$ 300.00	$ 300.00	142,200	142,200	0.00%
All Energy	$ 0.03810	$ 0.03823	14,198,005	14,246,450	0.34%
Demand kVa Base	$ 3.98	$ 3.54	3,530,133	3,139,867	-11.06%
Demand kVa Intermediate	$ 4.13	$ 3.69	3,395,170	3,033,457	-10.65%
Demand kVa Peak	$ 5.83	$ 5.04	4,688,002	4,052,750	-13.55%
Total Calculated			25,953,510	24,614,723	
Correction Factor			1.000000308	1.000000308	
Net FAC, ECR, DSM Revenues			3,984,681	3,984,681	0.00%
Total			29,938,183	28,599,396	**-4.47%**
INDUSTRIAL					
Basic Service Charges	$ 300.00	$ 300.00	252,600	252,600	0.00%
All Energy	$ 0.03538	$ 0.03823	59,100,300	63,861,065	8.06%
Demand kVa Base	$ 3.63	$ 3.54	14,897,887	14,528,518	-2.48%
Demand kVa Intermediate	$ 3.79	$ 3.69	14,121,385	13,748,789	-2.64%
Demand kVa Peak	$ 4.63	$ 5.04	17,022,024	18,529,374	8.86%
Total Calculated			105,394,195	110,920,344	
Correction Factor			0.9999999430	0.9999999430	
Net FAC, ECR, DSM Revenues			17,873,059	17,873,059	0.00%
Total			123,267,260	128,793,410	**4.48%**
TOTAL					
Basic Service Charges		$ 300.00	394,800	394,800	0.00%
All Energy		$ 0.03823	73,298,305	78,107,514	6.56%
Demand kVa Base		$ 3.54	18,428,019	17,668,384	-4.12%
Demand kVa Intermediate		$ 3.69	17,516,554	16,782,245	-4.19%
Demand kVa Peak		$ 5.04	21,710,026	22,582,123	4.02%
Total Calculated			131,347,704	135,535,067	
Correction Factor			1.000000015	1.000000015	
Net FAC, ECR, DSM Revenues			21,857,740	21,857,740	0.00%
Total			153,205,442	157,392,805	**2.73%**

As I discussed earlier in my testimony, I support the Company's apportionment of the increase to rate classes, including the TODP class. However as shown in Table 8, current commercial customers on the consolidated TODP rate would receive a

<u>4.47% decrease</u>, while current industrial customers would receive a <u>4.48% increase</u>. This decrease of 4.47% and increase of 4.48%, compared to the average 2.73% increase for the rate reflects an unreasonable level of disparity that is not supported by any cost of service analysis or, more importantly, any principle of gradualism.

Q. What is your recommendation on this issue?

A. Consistent with the principle of gradualism, I recommend that the individual CTODP and ITODP rates be continued as separate rate schedules. However, in recognition that these rate should be merged in the future, I recommend that the CTODP rate receive an increase 1% less than the ITODP rate. These rates can then be consolidated in future base rate cases, subject to evaluating the impacts on customers.

Q. Have you developed alternative CTODP and ITODP rates, reflecting your 1% differential proposal?

A. Yes. Table 9 shows the rates reflecting this differential, based on the Company's requested increase level. These rates would, of course, need to be adjusted in the event that the Commission approves a lower overall increase in this case.

Table 9
Time-of-Day Primary
KIUC Proposed Revenue Increases

	Present Rates	Proposed Rates	Present Revenues	Proposed Revenues	% Change
COMMERCIAL					
Basic Service Charges	$ 300.00	$ 300.00	142,200	142,200	0.00%
All Energy	$ 0.03810	$ 0.04122	14,198,005	15,361,929	8.20%
Demand kVa Base	$ 3.98	$ 3.82	3,530,133	3,385,714	-4.09%
Demand kVa Intermediate	$ 4.13	$ 3.98	3,395,170	3,270,973	-3.66%
Demand kVa Peak	$ 5.83	$ 5.43	4,688,002	4,370,075	-6.78%
Total Calculated			25,953,510	26,530,891	2.22%
Correction Factor			1.000000308	1.000000308	
Net FAC, ECR, DSM Revenues			3,984,681	3,984,681	0.00%
Total			29,938,183	30,515,564	**1.93%**
INDUSTRIAL					
Basic Service Charges	$ 300.00	$ 300.00	252,600	252,600	0.00%
All Energy	$ 0.03538	$ 0.03757	59,100,300	62,755,335	6.18%
Demand kVa Base	$ 3.63	$ 3.48	14,897,887	14,276,962	-4.17%
Demand kVa Intermediate	$ 3.79	$ 3.63	14,121,385	13,510,734	-4.32%
Demand kVa Peak	$ 4.63	$ 4.95	17,022,024	18,208,545	6.97%
Total Calculated			105,394,195	109,004,176	3.43%
Correction Factor			0.9999999430	0.9999999430	
Net FAC, ECR, DSM Revenues			17,873,059	17,873,059	0.00%
Total			123,267,260	126,877,241	**2.93%**
TOTAL					
Basic Service Charges			394,800	394,800	0.00%
All Energy			73,298,305	78,117,264	6.57%
Demand kVa Base			18,428,019	17,662,676	-4.15%
Demand kVa Intermediate			17,516,554	16,781,707	-4.20%
Demand kVa Peak			21,710,026	22,578,620	4.00%
Total Calculated			131,347,704	135,535,067	
Correction Factor			1.000000015	1.000000015	
Net FAC, ECR, DSM Revenues			21,857,740	21,857,740	0.00%
Total			153,205,442	157,392,805	**2.73%**

Q. Are there any additional rate design issues that you would like to address?

A. Yes. KIUC witness Lane Kollen is recommending that the operating expenses associated with the Green River Units 3 and 4 be deferred in this case due to their expected retirement. As a secondary recommendation, Mr. Kollen is recommending that a Retirement Rider be established to recover these operating expenses. These expenses would then be removed from base rate recovery.

Currently, these operating expenses are recovered in base rates and are allocated to rat classes in the Company's class cost of service study using the BIP production demand allocation factor. If Mr. Kollen's secondary recommendation to implement a Retirement Rider is adopted by the Commission, the Retirement Rider costs should be allocated to rate classes in the same manner as they are allocated in base rates – that is, using the BIP rate class production demand allocation factors developed by the KU in its class cost of service study. This would result in each rate class being allocated approximately the same amount of these operating expenses in the rider as was allocated in base rates. Specifically, there should be a separate charge for each rate class in the Retirement Rider that would be derived by applying KU's test year BIP allocation factors to the total amount of Retirement Rider revenue recovery for the month. The individual charges for each rate class would be calculated on a $/kWh basis for rate classes, such as the residential class, that are not demand metered. For larger rate classes, such as TODP or RTS, the allocated Retirement Rider charge should be calculated on a $/kW basis.

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

Stephen J. Baron

Sworn to and subscribed before me on this
6th day of March 2015.

Notary Public

LEAH J WELLBORN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
MAY 28, 2017
FULTON 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 ITS ELECTRIC RATES	**)**	**2014-00371**

IN THE MATTER OF:

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

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

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 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, 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 list of his specific regulatory appearances follows.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

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.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

Date	Case	Jurisdict.	Party	Utility	Subject
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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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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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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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.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

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

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

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

**Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015**

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

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

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

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

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

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

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 -00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2015

Date	Case	Jurisdict.	Party	Utility	Subject
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 EI-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY
KIUC Corrected BIP Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2016

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 1,053,711,901	$ 430,091,952	$ 147,539,590	$ 12,446,987	$ 167,766,803	$ 138,952,298	$ 79,565,770
Pro-Forma Adjustments:										
Remove Off-System ECR revenues			ECRREV	(8,932,269)	(3,166,102)	(1,077,975)	(121,786)	(1,473,810)	(1,498,377)	(766,536)
Customer Account Changes				(127,588)						21,060
Total Pro-Forma Operating Revenue				$ 1,044,652,044	$ 426,925,849	$ 146,461,614	$ 12,325,201	$ 166,292,993	$ 137,453,922	$ 78,820,294
Cost of Service Summary -- Pro-Forma										
Operating Expenses										
Operation and Maintenance Expenses				$ 698,592,652	$ 293,280,328	$ 83,363,103	$ 8,234,866	$ 102,141,690	$ 100,269,243	$ 53,184,805
Depreciation and Amortization Expenses				117,218,435	60,858,458	13,174,647	1,049,976	13,623,285	12,023,175	6,805,963
Regulatory Credits				-	-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs				-	-	-	-	-	-	-
Amortization Expense				-	-	-	-	-	-	-
Property and Other Taxes			NPT	29,879,058	15,422,360	3,356,892	271,053	3,512,409	3,104,461	1,755,581
Amortization of Investment Tax Credit				(1,214,862)	(627,063)	(136,489)	(11,021)	(142,812)	(126,225)	(71,381)
Other Expenses				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	58,309,040	11,776,854	15,566,037	893,994	15,744,133	6,643,275	5,451,000
Specific Assignment of Interruptible Credit				(3,438,312)	-	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	3,438,312	1,724,912	374,721	36,274	468,891	391,153	228,576
Adjustments to Operating Expenses:										
Property insurance expense adjustment			UPT	1,078,924	557,926	121,232	9,749	126,379	111,649	63,158
Eliminate advertising expenses			REVUC	(560,632)	(223,572)	(79,930)	(6,714)	(90,772)	(75,032)	(42,939)
Cane Run Depreciation adjustment			DEPPT	79,118	35,686	8,813	912	11,567	10,483	5,829
Federal & State Income Tax Interest Adjustment			TAXINC	2,204,193	445,188	588,426	33,795	595,158	251,129	206,058
Total Expense Adjustments				2,801,603	815,227	638,540	37,742	642,333	298,228	232,106
Total Operating Expenses		TOE		$ 905,585,926	$ 383,251,076	$ 116,337,451	$ 10,512,885	$ 135,989,929	$ 122,603,310	$ 67,586,650
Net Operating Income -- Pro-Forma				$ 139,066,118	$ 43,674,773	$ 30,124,163	$ 1,812,316	$ 30,303,065	$ 14,850,612	$ 11,233,644
Cost of Service Summary -- Pro-Forma										
Net Operating Income -- Pro-Forma				$ 139,066,118	$ 43,674,773	$ 30,124,163	$ 1,812,316	$ 30,303,065	$ 14,850,612	$ 11,233,644
Net Cost Rate Base				$ 2,250,031,690	$ 1,152,783,456	$ 253,344,655	$ 20,660,731	$ 267,161,152	$ 237,307,551	$ 133,781,296
ECR Plan Eliminations			PLPPT	-	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve			DET	-	-	-	-	-	-	-
Cash Working Capital			OMLF	-	-	-	-	-	-	-
Adjusted Net Cost Rate Base				$ 2,250,031,690	$ 1,152,783,456	$ 253,344,655	$ 20,660,731	$ 267,161,152	$ 237,307,551	$ 133,781,296
Rate of Return				**6.18%**	**3.79%**	**11.89%**	**8.77%**	**11.34%**	**6.26%**	**8.40%**

LOUISVILLE GAS AND ELECTRIC COMPANY
KIUC Corrected BIP Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2016

Description	Ref	Name	Allocation Vector	Rate RTS Transmission	Special Contract Customer #1	Special Contract Customer #2	Street Lighting Rate RLS, LS, DSK	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 47,243,012	$ 6,808,592	$ 3,629,277	$ 19,137,138	$ 242,164	$ 288,317
Pro-Forma Adjustments:									
Remove Off-System ECR revenues			ECRREV	(626,615)	(76,746)	(41,139)	(83,182)	-	-
Customer Account Changes					(148,648)				
Total Pro-Forma Operating Revenue				$ 46,616,397	$ 6,583,198	$ 3,588,138	$ 19,053,956	$ 242,164	$ 288,317
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 40,337,931	$ 5,465,681	$ 2,950,172	$ 8,991,511	$ 185,609	$ 187,711
Depreciation and Amortization Expenses				4,000,750	697,081	415,690	4,518,342	26,547	24,521
Regulatory Credits				-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-
Depreciation for Asset Retirement Costs				-	-	-	-	-	-
Amortization Expense				-	-	-	-	-	-
Property and Other Taxes			NPT	1,041,501	180,004	107,459	1,114,286	6,805	6,246
Amortization of Investment Tax Credit				(42,347)	(7,319)	(4,369)	(45,306)	(277)	(254)
Other Expenses				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	1,245,423	45,201	(19,711)	937,082	3,852	21,900
Specific Assignment of Interruptible Credit				(3,438,312)	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	136,618	24,031	16,003	35,707	818	609
Adjustments to Operating Expenses:									
Property insurance expense adjustment			UPT	37,362	6,474	3,863	40,662	245	226
Eliminate advertising expenses			REVUC	(25,434)	(3,615)	(1,889)	(10,448)	(129)	(158)
Cane Run Depreciation adjustment			DEPPT	3,993	609	370	819	20	16
Federal & State Income Tax Interest Adjustment			TAXINC	47,079	1,709	(745)	35,423	146	828
Total Expense Adjustments				63,000	5,176	1,599	66,458	282	911
Total Operating Expenses		TOE		$ 43,344,564	$ 6,409,857	$ 3,466,843	$ 15,618,079	$ 223,637	$ 241,645
Net Operating Income -- Pro-Forma				$ 3,271,834	$ 173,341	$ 121,295	$ 3,435,877	$ 18,526	$ 46,672
Cost of Service Summary -- Pro-Forma									
Net Operating Income -- Pro-Forma				$ 3,271,834	$ 173,341	$ 121,295	$ 3,435,877	$ 18,526	$ 46,672
Net Cost Rate Base				$ 80,460,973	$ 13,719,789	$ 8,155,713	$ 81,665,121	$ 515,886	$ 475,366
ECR Plan Eliminations			PLPPT	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve			DET	-	-	-	-	-	-
Cash Working Capital			OMLF	-	-	-	-	-	-
Adjusted Net Cost Rate Base				$ 80,460,973	$ 13,719,789	$ 8,155,713	$ 81,665,121	$ 515,886	$ 475,366
Rate of Return				**4.07%**	**1.26%**	**1.49%**	**4.21%**	**3.59%**	**9.82%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY
KIUC Corrected BIP Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GS	All Electric Schools AES	Power Service PS-Secondary	Power Service PS-Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 1,416,158,457	$ 539,052,950	$ 194,894,537	$ 11,379,563	$ 176,190,516	$ 18,406,796
Pro-Forma Adjustments:									
Adj to reflect Additional Redundant Capacity Revenue				287,062				$ 4,023	$ 9,750
Adj to reflect Revenue due to Metering changes				(462,863)					
Adj to reflect Lost Lighting Revenue				(270,352)					
Adj to reflect new Standby Service Customer				115,104					
Adj to eliminate Off System ECR revenues			OSSALL	(2,425,076)	$ (938,969)	$ (241,839)	$ (20,183)	$ (257,588)	$ (30,379)
Remove off-system ECR revenues			OSSALL	-	$ -	$ -	$ -	$ -	$ -
To adjust Off-system sales margins			OSSALL	-	$ -	$ -	$ -	$ -	$ -
Eliminate brokered sales revenues			Energy	-	$ -	$ -	$ -	$ -	$ -
Eliminate DSM revenues		DSMREV	DSM01	-	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	-	$ -	$ -	$ -	$ -	$ -
Remove Out of Period Items			RBT	-	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 1,413,402,331	$ 538,113,981	$ 194,652,698	$ 11,359,380	$ 175,936,951	$ 18,386,167
Operating Expenses									
Operation and Maintenance Expenses				$ 957,152,611	$ 372,414,107	$ 109,575,948	$ 7,749,853	$ 96,994,753	$ 10,830,711
Depreciation and Amortization Expenses				189,760,380	89,742,696	21,472,285	1,497,278	16,677,476	2,006,989
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	22,812,447	10,791,681	2,582,269	179,962	2,004,027	241,146
Other Taxes				12,214,063	5,777,998	1,382,579	96,354	1,072,980	129,112
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	58,839,387	$ 5,923,682	$ 19,242,695	$ 427,255	$ 19,899,178	$ 1,626,211
Specific Assignment of Curtailable Service Rider Credit				(11,877,948)	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 11,877,948	$ 5,637,391	$ 1,147,333	$ 102,953	$ 1,143,536	$ 151,265
Total Expense Adjustments				$ 5,579,245	$ 459,478	$ 1,909,113	$ 40,590	$ 1,986,467	$ 161,544
Total Operating Expenses		TOE		$ 1,246,358,133	$ 490,747,033	$ 157,312,222	$ 10,094,245	$ 139,778,417	$ 15,146,977
Net Operating Income (Adjusted)				$ 167,044,198	$ 47,366,948	$ 37,340,476	$ 1,265,135	$ 36,158,534	$ 3,239,190
Net Cost Rate Base				$ 3,669,268,542	$ 1,730,863,509	$ 417,109,458	$ 28,912,953	$ 322,469,108	$ 38,663,232
ECR Plan Eliminations			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ -	$ -	$ -	$ -	$ -	$ -
Cash Working Capital			OMLF	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted Net Cost Rate Base				$ 3,669,268,542	$ 1,730,863,509	$ 417,109,458	$ 28,912,953	$ 322,469,108	$ 38,663,232
Rate of Return				**4.55%**	**2.74%**	**8.95%**	**4.38%**	**11.21%**	**8.38%**

KENTUCKY UTILITIES COMPANY
KIUC Corrected BIP Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Service RTS	Service FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 102,840,966	$ 243,697,740	$ 87,526,248	$ 16,366,724	$ 25,660,590	$ 11,167	$ 130,661
Pro-Forma Adjustments:										
Adj to reflect Additional Redundant Capacity Revenue				$ 95,207	$ 178,082					
Adj to reflect Revenue due to Metering changes					$ (141,053)	$ (321,810)				
Adj to reflect Lost Lighting Revenue								$ (288,163)	$ 17,811	
Adj to reflect new Standby Service Customer					$ 115,104					
Adj to eliminate Off System ECR revenues			OSSALL	$ (186,807)	$ (486,001)	$ (178,828)	$ (59,481)	$ (24,821)	$ (42)	$ (139)
Remove off-system ECR revenues			OSSALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
To adjust Off-system sales margins			OSSALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate brokered sales revenues			Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate DSM revenues		DSMREV	DSM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Remove Out of Period Items			RBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 102,749,366	$ 243,363,872	$ 87,025,610	$ 16,307,242	$ 25,347,606	$ 28,936	$ 130,522
Operating Expenses										
Operation and Maintenance Expenses				$ 71,585,568	$ 183,970,760	$ 65,804,371	$ 22,557,952	$ 15,574,814	$ 18,275	$ 75,498
Depreciation and Amortization Expenses				11,349,554	28,751,626	9,763,862	3,107,197	5,376,046	2,073	13,299
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,363,692	3,454,321	1,172,714	373,192	647,594	249	1,600
Other Taxes				730,137	1,849,486	627,885	199,812	346,730	133	857
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 4,712,033	$ 4,582,216	$ 2,105,051	$ (192,297)	$ 504,588	$ (4,124)	$ 12,899
Specific Assignment of Curtailable Service Rider Credit				-	(662,440)	(253,585)	(10,961,923)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 751,298	$ 1,949,788	$ 725,761	$ 216,300	$ 51,723	$ 85	$ 516
Total Expense Adjustments				$ 452,960	$ 400,859	$ 191,692	$ (21,971)	$ (2,337)	$ (426)	$ 1,276
Total Operating Expenses		TOE		$ 90,945,244	$ 224,296,614	$ 80,137,751	$ 15,278,262	$ 22,499,158	$ 16,266	$ 105,944
Net Operating Income (Adjusted)				$ 11,804,122	$ 19,067,257	$ 6,887,859	$ 1,028,981	$ 2,848,448	$ 12,670	$ 24,578
Net Cost Rate Base				$ 219,922,118	$ 556,869,428	$ 188,899,928	$ 60,299,999	$ 104,957,583	$ 40,816	$ 260,410
ECR Plan Eliminations			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Working Capital			OMLF	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted Net Cost Rate Base				$ 219,922,118	$ 556,869,428	$ 188,899,928	$ 60,299,999	$ 104,957,583	$ 40,816	$ 260,410
Rate of Return				**5.37%**	**3.42%**	**3.65%**	**1.71%**	**2.71%**	**31.04%**	**9.44%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY
KIUC PJM 5CP Cost of Service Study
Class Allocation

12 Months Ended June 30, 2016

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GS	All Electric Schools AES	Power Service PS-Secondary	Power Service PS-Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 1,416,158,457	$ 539,025,309	$ 195,316,553	$ 11,384,310	$ 176,506,182	$ 18,470,195
Pro-Forma Adjustments:									
Adj to reflect Additional Redundant Capacity Revenue				287,062				$ 4,023	$ 9,750
Adj to reflect Revenue due to Metering changes				(462,863)					
Adj to reflect Lost Lighting Revenue				(270,352)					
Adj to reflect new Standby Service Customer				115,104					
Adj to eliminate Off System ECR revenues			OSSALL	(2,425,076)	$ (937,767)	$ (260,306)	$ (20,391)	$ (271,402)	$ (33,154)
Remove off-system ECR revenues			OSSALL	-	$ -	$ -	$ -	$ -	$ -
To adjust Off-system sales margins			OSSALL	-	$ -	$ -	$ -	$ -	$ -
Eliminate brokered sales revenues			Energy	-	$ -	$ -	$ -	$ -	$ -
Eliminate DSM revenues		DSMREV	DSM01	-	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	-	$ -	$ -	$ -	$ -	$ -
Remove Out of Period Items			RBT	-	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 1,413,402,331	$ 538,087,542	$ 195,056,247	$ 11,363,919	$ 176,238,803	$ 18,446,791
Operating Expenses									
Operation and Maintenance Expenses				$ 957,152,611	$ 372,448,662	$ 111,416,939	$ 7,769,894	$ 98,390,392	$ 11,115,130
Depreciation and Amortization Expenses				189,760,380	89,624,397	23,269,343	1,517,494	18,021,598	2,276,926
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	22,812,447	10,777,473	2,798,106	182,390	2,165,463	273,567
Other Taxes				12,214,063	5,770,390	1,498,140	97,654	1,159,415	146,471
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	58,839,387	$ 6,211,541	$ 17,481,819	$ 408,722	$ 18,554,549	$ 1,360,442
Specific Assignment of Curtailable Service Rider Credit				(11,877,948)	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 11,877,948	$ 5,030,175	$ 1,318,856	$ 102,284	$ 1,323,788	$ 172,398
Total Expense Adjustments				$ 5,579,245	$ 488,868	$ 1,731,171	$ 38,720	$ 1,850,540	$ 134,685
Total Operating Expenses		TOE		$ 1,246,358,133	$ 490,351,506	$ 159,514,375	$ 10,117,157	$ 141,465,746	$ 15,479,619
Net Operating Income (Adjusted)				$ 167,044,198	$ 47,736,036	$ 35,541,872	$ 1,246,762	$ 34,773,057	$ 2,967,172
Net Cost Rate Base				$ 3,669,268,542	$ 1,728,678,541	$ 450,617,827	$ 29,289,821	$ 347,534,436	$ 43,697,607
ECR Plan Eliminations			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ -	$ -	$ -	$ -	$ -	$ -
Cash Working Capital			OMLF	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted Net Cost Rate Base				$ 3,669,268,542	$ 1,728,678,541	$ 450,617,827	$ 29,289,821	$ 347,534,436	$ 43,697,607
Rate of Return				**4.55%**	**2.76%**	**7.89%**	**4.26%**	**10.01%**	**6.79%**

KENTUCKY UTILITIES COMPANY
KIUC PJM 5CP Cost of Service Study
Class Allocation

12 Months Ended June 30, 2016

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Service RTS	Service FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 102,928,446	$ 243,568,039	$ 87,385,696	$ 16,030,453	$ 25,402,229	$ 10,735	$ 130,309
Pro-Forma Adjustments:										
Adj to reflect Additional Redundant Capacity Revenue				$ 95,207	$ 178,082					
Adj to reflect Revenue due to Metering changes					$ (141,053)	$ (321,810)				
Adj to reflect Lost Lighting Revenue								$ (288,163)	$ 17,811	
Adj to reflect new Standby Service Customer					$ 115,104					
Adj to eliminate Off System ECR revenues			OSSALL	$ (190,634)	$ (480,322)	$ (172,676)	$ (44,764)	$ (13,513)	$ (23)	$ (124)
Remove off-system ECR revenues			OSSALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
To adjust Off-system sales margins			OSSALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate brokered sales revenues			Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate DSM revenues		DSMREV	DSM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Remove Out of Period Items			RBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 102,833,018	$ 243,239,849	$ 86,891,210	$ 15,985,689	$ 25,100,553	$ 28,523	$ 130,186
Operating Expenses										
Operation and Maintenance Expenses				$ 71,956,038	$ 183,346,648	$ 65,158,367	$ 21,049,282	$ 14,411,020	$ 16,332	$ 73,907
Depreciation and Amortization Expenses				11,722,108	28,199,549	9,165,482	1,675,426	4,276,019	237	11,800
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,408,438	3,388,013	1,100,845	201,229	515,475	29	1,420
Other Taxes				754,095	1,813,984	589,406	107,740	275,992	15	760
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 4,316,309	$ 5,046,712	$ 2,667,749	$ 1,203,483	$ 1,576,051	$ (2,336)	$ 14,345
Specific Assignment of Curtailable Service Rider Credit				-	(662,440)	(253,585)	(10,961,923)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 876,584	$ 2,151,396	$ 762,136	$ 139,845	$ -	$ -	$ 486
Total Expense Adjustments				$ 412,917	$ 447,664	$ 248,513	$ 119,064	$ 105,926	$ (245)	$ 1,422
Total Operating Expenses		TOE		$ 91,446,489	$ 223,731,526	$ 79,438,913	$ 13,534,147	$ 21,160,483	$ 14,032	$ 104,140
Net Operating Income (Adjusted)				$ 11,386,529	$ 19,508,324	$ 7,452,297	$ 2,451,542	$ 3,940,070	$ 14,492	$ 26,045
Net Cost Rate Base				$ 226,867,355	$ 546,567,431	$ 177,737,977	$ 33,597,242	$ 84,441,282	$ 6,567	$ 232,456
ECR Plan Eliminations			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Working Capital			OMLF	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted Net Cost Rate Base				$ 226,867,355	$ 546,567,431	$ 177,737,977	$ 33,597,242	$ 84,441,282	$ 6,567	$ 232,456
Rate of Return				**5.02%**	**3.57%**	**4.19%**	**7.30%**	**4.67%**	**220.67%**	**11.20%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY
KIUC 12 CP Cost of Service Study
Class Allocation

12 Months Ended June 30, 2016

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GS	All Electric Schools AES	Power Service PS-Secondary	Power Service PS-Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 1,416,158,457	$ 539,104,852	$ 195,141,760	$ 11,422,253	$ 176,227,539	$ 18,449,910
Pro-Forma Adjustments:									
Adj to reflect Additional Redundant Capacity Revenue				287,062				$ 4,023	$ 9,750
Adj to reflect Revenue due to Metering changes				(462,863)					
Adj to reflect Lost Lighting Revenue				(270,352)					
Adj to reflect new Standby Service Customer				115,104					
Adj to eliminate Off System ECR revenues			OSSALL	(2,425,076)	$ (941,249)	$ (252,655)	$ (22,051)	$ (259,206)	$ (32,266)
Remove off-system ECR revenues			OSSALL	-	$ -	$ -	$ -	$ -	$ -
To adjust Off-system sales margins			OSSALL	-	$ -	$ -	$ -	$ -	$ -
Eliminate brokered sales revenues			Energy	-	$ -	$ -	$ -	$ -	$ -
Eliminate DSM revenues		DSMREV	DSM01	-	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	-	$ -	$ -	$ -	$ -	$ -
Remove Out of Period Items			RBT	-	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 1,413,402,331	$ 538,163,604	$ 194,889,105	$ 11,400,201	$ 175,972,356	$ 18,427,394
Operating Expenses									
Operation and Maintenance Expenses				$ 957,152,611	$ 372,814,408	$ 110,613,227	$ 7,944,359	$ 97,109,168	$ 11,021,860
Depreciation and Amortization Expenses				189,760,380	89,963,041	22,525,185	1,679,031	16,835,312	2,190,567
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	22,812,447	10,818,146	2,708,729	201,791	2,022,984	263,194
Other Taxes				12,214,063	5,792,167	1,450,286	108,042	1,083,130	140,917
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	58,839,387	$ 5,873,944	$ 18,223,676	$ 247,684	$ 19,737,167	$ 1,446,534
Specific Assignment of Curtailable Service Rider Credit				(11,877,948)	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 11,877,948	$ 5,058,470	$ 1,256,677	$ 115,782	$ 1,224,666	$ 165,182
Total Expense Adjustments				$ 5,579,245	$ 454,743	$ 1,806,160	$ 22,442	$ 1,970,083	$ 143,388
Total Operating Expenses		TOE		$ 1,246,358,133	$ 490,774,919	$ 158,583,940	$ 10,319,131	$ 139,982,510	$ 15,371,642
Net Operating Income (Adjusted)				$ 167,044,198	$ 47,388,684	$ 36,305,165	$ 1,081,071	$ 35,989,846	$ 3,055,752
Net Cost Rate Base				$ 3,669,268,542	$ 1,734,995,504	$ 436,736,535	$ 32,303,089	$ 325,405,821	$ 42,086,696
ECR Plan Eliminations			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ -	$ -	$ -	$ -	$ -	$ -
Cash Working Capital			OMLF	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted Net Cost Rate Base				$ 3,669,268,542	$ 1,734,995,504	$ 436,736,535	$ 32,303,089	$ 325,405,821	$ 42,086,696
Rate of Return				**4.55%**	**2.73%**	**8.31%**	**3.35%**	**11.06%**	**7.26%**

KENTUCKY UTILITIES COMPANY
KIUC 12 CP Cost of Service Study
Class Allocation

12 Months Ended June 30, 2016

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Service RTS	Service FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 102,766,606	$ 243,658,912	$ 87,513,310	$ 16,259,146	$ 25,472,858	$ 10,841	$ 130,470
Pro-Forma Adjustments:										
Adj to reflect Additional Redundant Capacity Revenue				$ 95,207	$ 178,082					
Adj to reflect Revenue due to Metering changes					$ (141,053)	$ (321,810)				
Adj to reflect Lost Lighting Revenue								$ (288,163)	$ 17,811	
Adj to reflect new Standby Service Customer					$ 115,104					
Adj to eliminate Off System ECR revenues			OSSALL	$ (183,550)	$ (484,300)	$ (178,262)	$ (54,774)	$ (16,605)	$ (27)	$ (131)
Remove off-system ECR revenues			OSSALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
To adjust Off-system sales margins			OSSALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate brokered sales revenues			Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate DSM revenues		DSMREV	DSM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Remove Out of Period Items			RBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 102,678,263	$ 243,326,745	$ 87,013,238	$ 16,204,372	$ 25,168,090	$ 28,624	$ 130,340
Operating Expenses										
Operation and Maintenance Expenses				$ 71,211,888	$ 183,764,489	$ 65,745,143	$ 22,100,829	$ 14,735,775	$ 16,816	$ 74,648
Depreciation and Amortization Expenses				11,033,099	28,586,429	9,708,779	2,649,055	4,576,711	685	12,486
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,325,684	3,434,480	1,166,098	318,167	551,590	82	1,502
Other Taxes				709,788	1,838,862	624,343	170,351	295,328	44	804
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 5,003,188	$ 4,661,029	$ 2,126,133	$ 232,865	$ 1,276,289	$ (2,783)	$ 13,662
Specific Assignment of Curtailable Service Rider Credit				-	(662,440)	(253,585)	(10,961,923)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 819,013	$ 2,183,722	$ 807,532	$ 221,198	$ 25,125	$ 37	$ 543
Total Expense Adjustments				$ 482,349	$ 408,678	$ 193,764	$ 20,951	$ 75,625	$ (290)	$ 1,353
Total Operating Expenses		TOE		$ 90,585,009	$ 224,215,249	$ 80,118,207	$ 14,751,493	$ 21,536,444	$ 14,592	$ 104,998
Net Operating Income (Adjusted)				$ 12,093,254	$ 19,111,496	$ 6,895,031	$ 1,452,878	$ 3,631,647	$ 14,032	$ 25,342
Net Cost Rate Base				$ 214,014,794	$ 553,784,167	$ 187,872,463	$ 51,759,010	$ 90,050,292	$ 14,926	$ 245,246
ECR Plan Eliminations			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Working Capital			OMLF	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted Net Cost Rate Base				$ 214,014,794	$ 553,784,167	$ 187,872,463	$ 51,759,010	$ 90,050,292	$ 14,926	$ 245,246
Rate of Return				**5.65%**	**3.45%**	**3.67%**	**2.81%**	**4.03%**	**94.01%**	**10.33%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY
KIUC PJM 5 CP Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2016

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 1,053,711,901	$ 435,364,058	$ 148,891,370	$ 12,408,638	$ 167,321,556	$ 137,084,393	$ 79,211,289
Pro-Forma Adjustments:										
Remove Off-System ECR revenues			ECRREV	(8,932,269)	(3,166,102)	(1,077,975)	(121,786)	(1,473,810)	(1,498,377)	(766,536)
Customer Account Changes				(127,588)						21,060
Total Pro-Forma Operating Revenue				$ 1,044,652,044	$ 432,197,955	$ 147,813,394	$ 12,286,852	$ 165,847,746	$ 135,586,016	$ 78,465,813
Cost of Service Summary -- Pro-Forma										
Operating Expenses										
Operation and Maintenance Expenses				$ 698,592,652	$ 299,652,165	$ 84,996,856	$ 8,188,518	$ 101,603,566	$ 98,011,703	$ 52,756,381
Depreciation and Amortization Expenses				117,218,435	64,668,069	14,151,439	1,022,265	13,301,550	10,673,431	6,549,816
Regulatory Credits				-	-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs				-	-	-	-	-	-	-
Amortization Expense				-	-	-	-	-	-	-
Property and Other Taxes			NPT	29,879,058	16,414,297	3,611,227	263,838	3,428,636	2,753,018	1,688,886
Amortization of Investment Tax Credit				(1,214,862)	(667,394)	(146,830)	(10,727)	(139,406)	(111,936)	(68,669)
Other Expenses				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	58,309,040	8,884,688	14,804,524	914,241	15,981,179	7,666,936	5,640,544
Specific Assignment of Interruptible Credit				(3,438,312)	-	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	3,438,312	1,716,606	425,493	38,429	488,699	396,832	242,171
Adjustments to Operating Expenses:										
Property insurance expense adjustment			UPT	1,078,924	593,507	130,355	9,490	123,374	99,043	60,765
Eliminate advertising expenses			REVUC	(560,632)	(223,572)	(79,930)	(6,714)	(90,772)	(75,032)	(42,939)
Cane Run Depreciation adjustment			DEPPT	79,118	39,500	9,791	884	11,245	9,131	5,573
Federal & State Income Tax Interest Adjustment			TAXINC	2,204,193	335,858	559,639	34,560	604,119	289,825	213,223
Total Expense Adjustments				2,801,603	745,293	619,854	38,221	647,967	322,967	236,623
Total Operating Expenses		TOE		$ 905,585,926	$ 391,413,724	$ 118,462,564	$ 10,454,784	$ 135,312,192	$ 119,712,952	$ 67,045,751
Net Operating Income -- Pro-Forma				$ 139,066,118	$ 40,784,232	$ 29,350,830	$ 1,832,068	$ 30,535,554	$ 15,873,065	$ 11,420,062
Cost of Service Summary -- Pro-Forma										
Net Operating Income -- Pro-Forma				$ 139,066,118	$ 40,784,232	$ 29,350,830	$ 1,832,068	$ 30,535,554	$ 15,873,065	$ 11,420,062
Net Cost Rate Base				$ 2,250,031,690	$ 1,225,741,672	$ 272,051,303	$ 20,130,039	$ 260,999,578	$ 211,458,479	$ 128,875,800
ECR Plan Eliminations			PLPPT	-	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve			DET	-	-	-	-	-	-	-
Cash Working Capital			OMLF	-	-	-	-	-	-	-
Adjusted Net Cost Rate Base				$ 2,250,031,690	$ 1,225,741,672	$ 272,051,303	$ 20,130,039	$ 260,999,578	$ 211,458,479	$ 128,875,800
Rate of Return				**6.18%**	**3.33%**	**10.79%**	**9.10%**	**11.70%**	**7.51%**	**8.86%**

LOUISVILLE GAS AND ELECTRIC COMPANY
KIUC PJM 5 CP Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2016

Description	Ref	Name	Allocation Vector	Rate RTS Transmission	Special Contract Customer #1	Special Contract Customer #2	Street Lighting Rate RLS, LS, DSK	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 44,768,505	$ 6,619,643	$ 3,542,986	$ 18,004,580	$ 214,220	$ 280,664
Pro-Forma Adjustments:									
Remove Off-System ECR revenues			ECRREV	(626,615)	(76,746)	(41,139)	(83,182)	-	-
Customer Account Changes					(148,648)				
Total Pro-Forma Operating Revenue				$ 44,141,890	$ 6,394,249	$ 3,501,846	$ 17,921,398	$ 214,220	$ 280,664
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 37,347,256	$ 5,237,319	$ 2,845,881	$ 7,622,707	$ 151,836	$ 178,462
Depreciation and Amortization Expenses				2,212,677	560,548	353,336	3,699,958	6,355	18,991
Regulatory Credits				-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-
Depreciation for Asset Retirement Costs				-	-	-	-	-	-
Amortization Expense				-	-	-	-	-	-
Property and Other Taxes			NPT	575,928	144,454	91,223	901,198	1,548	4,806
Amortization of Investment Tax Credit				(23,417)	(5,873)	(3,709)	(36,642)	(63)	(195)
Other Expenses				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	2,619,772	150,296	28,674	1,572,521	19,507	26,156
Specific Assignment of Interruptible Credit				(3,438,312)	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	95,748	20,506	13,362	-	-	468
Adjustments to Operating Expenses:									
Property insurance expense adjustment			UPT	20,661	5,198	3,281	33,019	57	174
Eliminate advertising expenses			REVUC	(25,434)	(3,615)	(1,889)	(10,448)	(129)	(158)
Cane Run Depreciation adjustment			DEPPT	2,203	472	307	-	-	11
Federal & State Income Tax Interest Adjustment			TAXINC	99,032	5,681	1,084	59,444	737	989
Total Expense Adjustments				96,462	7,737	2,783	82,015	665	1,015
Total Operating Expenses		TOE		$ 39,486,113	$ 6,114,987	$ 3,331,551	$ 13,841,758	$ 179,847	$ 229,703
Net Operating Income -- Pro-Forma				$ 4,655,777	$ 279,262	$ 170,295	$ 4,079,640	$ 34,372	$ 50,962
Cost of Service Summary -- Pro-Forma									
Net Operating Income -- Pro-Forma				$ 4,655,777	$ 279,262	$ 170,295	$ 4,079,640	$ 34,372	$ 50,962
Net Cost Rate Base				$ 46,217,422	$ 11,105,017	$ 6,961,567	$ 65,992,175	$ 129,178	$ 369,459
ECR Plan Eliminations			PLPPT	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve			DET	-	-	-	-	-	-
Cash Working Capital			OMLF	-	-	-	-	-	-
Adjusted Net Cost Rate Base				$ 46,217,422	$ 11,105,017	$ 6,961,567	$ 65,992,175	$ 129,178	$ 369,459
Rate of Return				**10.07%**	**2.51%**	**2.45%**	**6.18%**	**26.61%**	**13.79%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY
KIUC 12 CP Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2016

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 1,053,711,901	$ 430,906,008	$ 148,720,940	$ 12,472,960	$ 168,139,281	$ 138,306,624	$ 79,687,982
Pro-Forma Adjustments:										
Remove Off-System ECR revenues			ECRREV	(8,932,269)	(3,166,102)	(1,077,975)	(121,786)	(1,473,810)	(1,498,377)	(766,536)
Customer Account Changes				(127,588)						21,060
Total Pro-Forma Operating Revenue				$ 1,044,652,044	$ 427,739,906	$ 147,642,965	$ 12,351,175	$ 166,665,471	$ 136,808,248	$ 78,942,506
Cost of Service Summary -- Pro-Forma										
Operating Expenses										
Operation and Maintenance Expenses				$ 698,592,652	$ 294,264,192	$ 84,790,877	$ 8,266,258	$ 102,591,864	$ 99,488,885	$ 53,332,509
Depreciation and Amortization Expenses				117,218,435	61,446,693	14,028,288	1,068,745	13,892,436	11,556,613	6,894,273
Regulatory Credits				-	-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs				-	-	-	-	-	-	-
Amortization Expense				-	-	-	-	-	-	-
Property and Other Taxes			NPT	29,879,058	15,575,523	3,579,161	275,940	3,582,490	2,982,979	1,778,575
Amortization of Investment Tax Credit				(1,214,862)	(633,290)	(145,526)	(11,220)	(145,662)	(121,286)	(72,316)
Other Expenses				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	58,309,040	11,385,800	14,900,140	878,154	15,522,409	6,981,225	5,373,103
Specific Assignment of Interruptible Credit				(3,438,312)	-	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	3,438,312	1,576,444	420,134	40,451	514,409	435,259	257,158
Adjustments to Operating Expenses:										
Property insurance expense adjustment			UPT	1,078,924	563,420	129,204	9,924	128,893	107,292	63,983
Eliminate advertising expenses			REVUC	(560,632)	(223,572)	(79,930)	(6,714)	(90,772)	(75,032)	(42,939)
Cane Run Depreciation adjustment			DEPPT	79,118	36,275	9,668	931	11,837	10,016	5,917
Federal & State Income Tax Interest Adjustment			TAXINC	2,204,193	430,405	563,254	33,196	586,777	263,904	203,114
Total Expense Adjustments				2,801,603	806,528	622,195	37,337	636,735	306,179	230,075
Total Operating Expenses		TOE		$ 905,585,926	$ 384,421,890	$ 118,195,269	$ 10,555,665	$ 136,594,680	$ 121,629,852	$ 67,793,378
Net Operating Income -- Pro-Forma				$ 139,066,118	$ 43,318,016	$ 29,447,696	$ 1,795,509	$ 30,070,790	$ 15,178,395	$ 11,149,128
Cost of Service Summary -- Pro-Forma										
Net Operating Income -- Pro-Forma				$ 139,066,118	$ 43,318,016	$ 29,447,696	$ 1,795,509	$ 30,070,790	$ 15,178,395	$ 11,149,128
Net Cost Rate Base				$ 2,250,031,690	$ 1,164,048,805	$ 269,692,813	$ 21,020,168	$ 272,315,692	$ 228,372,368	$ 135,472,529
ECR Plan Eliminations			PLPPT	-	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve			DET	-	-	-	-	-	-	-
Cash Working Capital			OMLF	-	-	-	-	-	-	-
Adjusted Net Cost Rate Base				$ 2,250,031,690	$ 1,164,048,805	$ 269,692,813	$ 21,020,168	$ 272,315,692	$ 228,372,368	$ 135,472,529
Rate of Return				**6.18%**	**3.72%**	**10.92%**	**8.54%**	**11.04%**	**6.65%**	**8.23%**

LOUISVILLE GAS AND ELECTRIC COMPANY
KIUC 12 CP Cost of Service Study
Class Allocation

12 Months Ended
June 30, 2016

Description	Ref	Name	Allocation Vector	Rate RTS Transmission	Special Contract Customer #1	Special Contract Customer #2	Street Lighting Rate RLS, LS, DSK	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 46,244,368	$ 6,671,893	$ 3,612,663	$ 18,438,506	$ 224,937	$ 285,740
Pro-Forma Adjustments:									
Remove Off-System ECR revenues			ECRREV	(626,615)	(76,746)	(41,139)	(83,182)	-	-
Customer Account Changes					(148,648)				
Total Pro-Forma Operating Revenue				$ 45,617,753	$ 6,446,499	$ 3,571,523	$ 18,355,324	$ 224,937	$ 285,740
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 39,130,975	$ 5,300,467	$ 2,930,092	$ 8,147,148	$ 164,789	$ 184,596
Depreciation and Amortization Expenses				3,279,132	598,303	403,684	4,013,512	14,099	22,658
Regulatory Credits				-	-	-	-	-	-
Accretion Expense				-	-	-	-	-	-
Depreciation for Asset Retirement Costs				-	-	-	-	-	-
Amortization Expense				-	-	-	-	-	-
Property and Other Taxes			NPT	853,608	154,284	104,333	982,840	3,564	5,761
Amortization of Investment Tax Credit				(34,707)	(6,273)	(4,242)	(39,962)	(145)	(234)
Other Expenses				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	1,791,765	120,983	(10,417)	1,329,075	13,494	23,309
Specific Assignment of Interruptible Credit				(3,438,312)	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	142,149	22,149	15,553	13,643	337	627
Adjustments to Operating Expenses:									
Property insurance expense adjustment			UPT	30,622	5,551	3,751	35,947	129	208
Eliminate advertising expenses			REVUC	(25,434)	(3,615)	(1,889)	(10,448)	(129)	(158)
Cane Run Depreciation adjustment			DEPPT	3,271	510	358	314	8	14
Federal & State Income Tax Interest Adjustment			TAXINC	67,732	4,573	(394)	50,242	510	881
Total Expense Adjustments				76,190	7,019	1,826	76,055	518	945
Total Operating Expenses		TOE		$ 41,800,800	$ 6,196,933	$ 3,440,830	$ 14,522,311	$ 196,656	$ 237,663
Net Operating Income -- Pro-Forma				$ 3,816,953	$ 249,566	$ 130,694	$ 3,833,013	$ 28,281	$ 48,077
Cost of Service Summary -- Pro-Forma									
Net Operating Income -- Pro-Forma				$ 3,816,953	$ 249,566	$ 130,694	$ 3,833,013	$ 28,281	$ 48,077
Net Cost Rate Base				$ 66,641,196	$ 11,828,070	$ 7,925,795	$ 71,997,070	$ 277,487	$ 439,694
ECR Plan Eliminations			PLPPT	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve			DET	-	-	-	-	-	-
Cash Working Capital			OMLF	-	-	-	-	-	-
Adjusted Net Cost Rate Base				$ 66,641,196	$ 11,828,070	$ 7,925,795	$ 71,997,070	$ 277,487	$ 439,694
Rate of Return				**5.73%**	**2.11%**	**1.65%**	**5.32%**	**10.19%**	**10.93%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 55

Responding Witness: David S. Sinclair

Q.1-55. With regard to Mr. Sinclair's testimony on page 27 wherein he discusses the proposed change in the CSR limitation on physical curtailment criterion (i.e., "none" vs. "only during system reliability events"), please identify the criterion that the Companies intend to use to determine if it should interrupt CSR load.

A.1-55. The Companies will attempt to optimize the utilization of the 100 hours to address system conditions and reduce system fuel and purchase power costs.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015**

Question No. 58

Responding Witness: David S. Sinclair

Q.1-58. Please provide an explanation of the methodology used by the Companies to reflect curtailable/interruptible load in resource planning studies and analyses.

A.1-58. The Companies' practice of modeling the Direct Load Control ("DLC") program is to use it to reduce load at the peak summer hour. The Companies' practice of modeling CSR is to use it as a resource to meet load obligations.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-10)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

**Response to Sierra Club's Initial Data Requests
Dated January 8, 2015**

Question No. 10

Responding Witness: David E. Huff / Dr. Martin J. Blake

Q-10. Reference Martin Blake, p. 23, ll. 12-14.

a) By "fixed production and transmission costs," does Dr. Blake mean demand-related production and transmission plant costs? Please explain.

b) Would Dr. Blake agree that these production and transmission plant costs are "fixed" in the sense that they are sunk? Please explain.

c) Has Dr. Blake or the Company compared the proposed on-peak energy rate against a forecast of the generation and transmission costs avoided by a shift from on-peak to off-peak usage? If so, please provide copies of all workpapers or other documentation of such analyses.

d) Please provide the Company's current forecast of avoided generation, transmission, and distribution costs used to screen DSM measures and programs for cost-effectiveness.

A-10. a) Yes, as well as any other production and transmission cost that is fixed, such as fixed operations and maintenance expenses.

b) Yes, fixed production and transmission plant costs do not change and are frequently referred to as sunk costs.

c) No.

d) Please see attachment for system avoided energy costs. Transmission and distribution capacity costs are pieces of avoided energy costs and are not available as separate values. System avoided capacity cost are $100/kW-yr.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-11)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated February 17, 2014

Case No. 2014-00003

Question No. 21

Witness: Michael E. Hornung

Q-21. Reference the Hornung testimony, p. 20 beginning at line 4. Please explain what is meant by, "…due to the current market conditions and costs."

A-21. The quoted phrase addresses the Companies' avoided cost of capacity compared to the cost of deploying the various energy-efficiency measures outlined within the Cadmus Market Potential Study. For example, any energy-efficiency measure incentive is capped at the Companies' avoided cost of capacity ($100/kW-year), as it would be otherwise more economical to serve energy from supply-side resources.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-12)

OF

STEPHEN J. BARON

With the addition of Green River 5 and Brown Solar, the Companies reserve margin in 2018 is expected to be approximately 22%. SCCT capacity is added to or subtracted from the Companies' generating portfolio to simulate the system at different reserve margin levels. The following sections discuss the cost and operating characteristics of this SCCT capacity as well as unit availability inputs and fuel prices for all units modeled in SERVM. A discussion of interruptible contracts is also included.

4.4.1 Marginal SCCT Capacity

In this analysis, SCCT capacity is added or subtracted from the Companies' generating portfolio to simulate the system at different reserve margin levels. SCCT capacity is the least-cost alternative for meeting peak energy needs (see the report titled *2014 Resource Assessment* at page 29; this report is located in Volume III, Technical Appendix). Table 5 summarizes the assumed cost of this SCCT capacity.

Table 5 – SCCT Cost

Input Assumption	Value
Capital Cost (2013 $/kW)	587
Fixed O&M (2013 $/kW-yr)	7.3
Firm Gas Transport (2013 $/kW-yr)	20.66
Escalation Rate	1.8%
Discount Rate	6.52%
Carrying Charge (2018 $/kW-yr)	88.2

4.4.2 Unit Availability Inputs

A major component of reliability analyses is modeling the availability of supply resources after considering planned and forced outages. Forced outages for conventional generation units are modeled stochastically, with partial and full forced outages occurring probabilistically based on distributions accounting for time-to-fail, time-to-repair, and partial outage derate percentages. Maintenance outages also occur stochastically, but SERVM accommodates maintenance outages with some flexibility to schedule maintenance during off-peak hours. Planned outages are differentiated from maintenance outages and are assumed to be scheduled such that there is no negative impact on system reliability.

Time-to-fail and time-to-repair distributions for partial and full forced outages were developed from historical Generation Availability Data System ("GADS") data for units in the Companies' generating portfolio. Distributions for partial outage derate percentages were also developed based on this data. The EFORs for the Companies' generating units are summarized in Table 4 (Section 4.4). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio.

4.4.3 Fuel Prices

The forecast of natural gas and coal prices used in this analysis are summarized in Table 6. These fuel prices are the fuel prices used in the Companies' 2014 Resource Assessment for the Integrated Resource Plan. A transportation cost was added to these prices to estimate delivered fuel prices to the Companies' generating units and to neighboring regions.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-13)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 8, 2015

Question No. 53

Responding Witness: David S. Sinclair / Robert M. Conroy

Q.1-53. With respect to the Curtailable Service Rider ("CSR"), please provide the kW amount of load and number of customers, by month, for 2012, 2013, 2014, and for the projected test year ending June 2016 on each of the CSR options, by rate schedule and by Company.

A.1-53. The Company does not forecast load for all customers on the CSR riders. See Attachment 1 for the requested load data for 2012-2014 for all CSR customers, and Attachment 2 for the forecast load data for one CSR customer. Note that the load data is in kVA rather than in kW.

Attachment 2 to Response to KIUC Question No. 1-53
Page 1 of 1
Sinclair

Forecast kVA by Billing Period

	Base	Intermediate	Peak	Rate	Customers
7/1/2015	185,158	185,158	101,388	FLS	1
8/1/2015	185,158	185,158	101,388	FLS	1
9/1/2015	185,158	185,158	101,388	FLS	1
10/1/2015	185,158	185,158	101,388	FLS	1
11/1/2015	185,158	185,158	101,388	FLS	1
12/1/2015	185,158	185,158	101,388	FLS	1
1/1/2016	185,158	185,158	101,388	FLS	1
2/1/2016	185,158	185,158	101,388	FLS	1
3/1/2016	185,158	185,158	101,388	FLS	1
4/1/2016	185,158	185,158	101,388	FLS	1
5/1/2016	185,158	185,158	101,388	FLS	1
6/1/2016	185,158	185,158	101,388	FLS	1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

IN THE MATTER OF:

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

EXHIBIT__(SJB-14)

OF

STEPHEN J. BARON

RPM CONE and E&AS Values for 2017/2018 Base Residual Auction

ICAP to UCAP Conversion Factor:	
UCAP Price = ICAP Price/(1 - Pool-Wide Average EFORd)	
Pool-Wide Average EFORd for 2017/2018 =	**5.65%**
CONE Area 1: AE, DPL, JCPL, PECO, PS, RECO	
CONE Area 2: BGE, PEPCO	
CONE Area 3: AEP, APS, ATSI, ComEd, Dayton, DEOK, Duquesne (DLCo), EKPC	
CONE Area 4: MetEd, Penelec, PPL	
CONE Area 5: Dominion	
MAAC CONE used is the lowest of the three CONE Areas 1, 2, and 4.	

	CONE Area 1	**CONE Area 2**	**CONE Area 3**	**CONE Area 4**	**CONE Area 5**	**MAAC: Used Area 2 CONE**	**RTO**
Benchmark CONE (2016/2017 BRA Value): Levelized Revenue Requirement, $/MW-Year	$152,460	$142,223	$139,485	$146,471	$124,920	$142,223	$139,392
12 Months Handy Whitman Index (July 1, 2013)	2.9%	2.9%	3.0%	2.9%	2.9%	2.9%	2.9%
Region basis for the Handy Whitman Index	North Atlantic	North Atlantic	North Central	North Atlantic	South Atlantic	North Atlantic	North Atlantic
2017/2018 BRA CONE, escalated by Handy Whitman Index, $/MW-Year	$156,881	$146,348	$143,670	$150,718	$128,542	$146,348	$143,434
Gross CONE, $/MW-Day, UCAP Price	**$455.55**	**$424.96**	**$417.19**	**$437.65**	**$373.26**	**$424.96**	**$416.50**
Historic (2011-2013) Net Energy Revenue Offset, $/MW-Year	$28,686	$36,360	$12,761	$26,452	$26,492	$36,360	$20,224
Zonal LMP used for Net Energy Offset Calculation	AE Zonal LMP	BGE Zonal LMP	ComEd Zonal LMP	MetEd Zonal LMP	Dominion Zonal LMP	BGE Zonal LMP	PJM Average LMP
Ancillary Services Offset, $/MW-Year per Tariff	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199
Net CONE, $/MW-Day, ICAP Price	$345.20	$295.31	**$352.63**	$334.43	$273.56	$295.31	$331.54
Net CONE, $/MW-Day, UCAP Price	$365.87	$313.00	$373.75	$354.46	$289.95	$313.00	$351.39
VRR Curve Point (a) UCAP Price, $/MW-Day *	$548.81	$469.50	$560.63	$531.69	$434.93	$469.50	$527.09

* VRR Curve Point (a) UCAP Price is the higher of 1.5 Net CONE or Gross CONE.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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IN THE MATTER OF:

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

EXHIBIT__(SJB-15)

OF

STEPHEN J. BARON

Independent Statistics & Analysis
U.S. Energy Information Administration

April 2014

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014

This paper presents average values of levelized costs for generating technologies that are brought online in 2019[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2014* (AEO2014) Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while LCOE is a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly impact the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different economic value than one that would displace existing coal generation.

A related factor is the ***capacity value,*** which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less

[1] 2019 is shown because the long lead time needed for some technologies means that the plant could not be brought online prior to 2019 unless it was already under construction.
[2] The full report is available at http://www.eia.gov/forecasts/aeo/index.cfm.
[3] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.doe.gov/oiaf/aeo/index.html.

flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of LCOE across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments. The avoided cost is divided by average annual output of the project to develop the "levelized" avoided cost of electricity (LACE) for the project.[4] The LACE value may then be compared with the LCOE value for the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's LACE to its LCOE may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than estimating levelized costs because it requires information about how the system would have operated without the option under evaluation. In this discussion, the calculation of avoided costs is based on the marginal value of energy and capacity that would result from adding a unit of a given technology and represents the potential revenue available to the project owner from the sale of energy and generating capacity. While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net value estimates presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results.

Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on ***portfolio diversification***. While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations.

The LCOE values shown for each utility-scale generation technology in Table 1 and Table 2 in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.5%. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2014 reference case, 3 percentage points are added to the cost of capital when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-

[4] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found in this article: http://www.eia.gov/renewable/workshop/gencosts/.

fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). In LCOE terms, the impact of the cost of capital adder is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, which is representative of the costs used by utilities and regulators in their resource planning.[5] The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility that they may eventually have to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions. As a result, the LCOE values for coal-fired plants without CCS are higher than would otherwise be expected.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with permanent tax law, which vary by technology. Although the capital and operating components do not incorporate the production or investment tax credits available to some technologies, a subsidy column is included in Table 1 to reflect the estimated value of these tax credits, where available, in 2019. In the reference case, tax credits are assumed to expire based on current laws and regulations.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale generating plants and distributed end-use residential and commercial applications. As noted above, the LCOE (and also subsequent LACE) calculations presented in the tables apply only to the utility-scale use of those technologies.

In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. They should not be interpreted as representing EIA's estimate or projection of the gross generating potential of resources actually projected to be built.

As mentioned above, the LCOE values shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in LCOE values based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, LCOE for incremental wind capacity coming online in 2019 ranges from $71.3/MWh in the region with the best available resources in 2019 to $90.3/MWh in regions where LCOE values are highest due to lower quality wind resources and/or higher capital costs for the best sites that can accommodate additional wind capacity. Costs shown for wind may include additional costs associated with transmission upgrades needed to access

[5] Morgan Stanley, "Leading Wall Street Banks Establish The Carbon Principles" (Press Release, February 4, 2008), www.morganstanley.com/about/press/articles/6017.html.

remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

As previously indicated, LACE provides an estimate of the cost of generation and capacity resources displaced by a marginal unit of new capacity of a particular type, thus providing an estimate of the value of building such new capacity. This is especially important to consider for intermittent resources, such as wind or solar, that have substantially different duty cycles than the baseload, intermediate and peaking duty cycles of conventional generators. Table 3 provides the range of LACE estimates for different capacity types. The LACE estimates in this table have been calculated assuming the same maximum capacity factor as in the LCOE. A subset of the full list of technologies in Table 1 is shown because the LACE value for similar technologies with the same capacity factor would have the same value (for example, conventional and advanced combined cycle plants will have the same avoided cost of electricity). Values are not shown for combustion turbines, because turbines are more often built for their capacity value to meet a reserve margin rather than to meet generation requirements and avoid energy costs.

When the LACE of a particular technology exceeds its LCOE at a given time and place, that technology would generally be economically attractive to build. While the build decisions in the real world, and as modeled in the AEO, are somewhat more complex than a simple LACE to LCOE comparison, including such factors as policy and non-economic drivers, the net economic value (LACE minus LCOE, including subsidy, for a given technology, region and year) shown in Table 4 provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using either the LCOE or LACE tables individually. In Table 4, a negative difference indicates that the cost of the marginal new unit of capacity exceeds its value to the system, as measured by LACE; a positive difference indicates that the marginal new unit brings in value in excess of its cost by displacing more expensive generation and capacity options. The range of differences columns represent the variation in the calculation of the difference for each region. For example, in the region where the advanced combined cycle appears most economic in 2019, the LCOE is $61.5/MWh and the LACE is $62.3/MWh, resulting in a net difference of $0.8/MWh. This range of differences is not based on the difference between the minimum values shown in Table 2 and Table 3, but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

The average net differences shown in Table 4 are for plants coming online in 2019, consistent with Tables 1-3, as well as for plants that could come online in 2040, to show how the relative competitiveness changes over the projection period. Additional tables showing the LCOE cost components and regional variation in LCOE and LACE for 2040 can be found in the Appendix. In 2019, the average net differences are negative for all technologies except geothermal, reflecting the fact that on average, new capacity is not needed in 2019. However, the upper value for both combined cycle technologies is at or above zero, indicating competiveness in a particular region. Geothermal cost data is site-specific, and the relatively large positive value for that technology results because there may be individual sites that are very cost competitive, leading to new builds, but there is a limited amount of capacity available at that cost. By 2040, the LCOE values for most technologies are lower, typically reflecting declining capital costs over time. All technologies receive cost reductions from learning over time, with newer, advanced technologies receiving larger cost reductions, while conventional technologies will see smaller learning effects. Capital costs are also adjusted over time based on commodity prices, through a factor based on the metals and metal products index, which declines in real terms over the projection. However, the LCOE for natural gas-fired technologies rises over time, because rising fuel costs more than offset any decline in capital costs. The LACE values for all technologies increase by 2040 relative to 2019, reflecting higher energy costs and a greater value for new capacity. As a result, the difference between LACE and LCOE for almost all technologies gets closer to a net positive value in 2040, and there are several technologies (advanced combined cycle, wind, solar PV, hydro and geothermal) that have multiple regions with positive net differences.

Table 1. Estimated levelized cost of electricity (LCOE) for new generation resources, 2019

	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2019							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Subsidy[1]**	**Total LCOE including Subsidy**
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced Combustion Turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind – Offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydroelectric[3]	53	72.0	4.1	6.4	2.0	84.5		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table 2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2019

	Range for Total System LCOE (2012 $/MWh)			Range for Total LCOE with Subsidies[1] (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies						
Conventional Coal	87.0	95.6	114.4			
IGCC	106.4	115.9	131.5			
IGCC with CCS	137.3	147.4	163.3			
Natural Gas-fired						
Conventional Combined Cycle	61.1	66.3	75.8			
Advanced Combined Cycle	59.6	64.4	73.6			
Advanced CC with CCS	85.5	91.3	105.0			
Conventional Combustion Turbine	106.0	128.4	149.4			
Advanced Combustion Turbine	96.9	103.8	119.8			
Advanced Nuclear	92.6	96.1	102.0	82.6	86.1	92.0
Geothermal	46.2	47.9	50.3	43.1	44.5	46.4
Biomass	92.3	102.6	122.9			
Non-Dispatchable Technologies						
Wind	71.3	80.3	90.3			
Wind – Offshore	168.7	204.1	271.0			
Solar PV[2]	101.4	130.0	200.9	92.6	118.6	182.6
Solar Thermal	176.8	243.1	388.0	162.6	223.6	356.7
Hydroelectric[3]	61.6	84.5	137.7			

[1]Levelized cost with subsidies reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005.

[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 31% to 45%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table 3: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2019

	Range for LACE (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies			
Coal-fired plant types without CCS	54.6	62.2	70.6
IGCC with CCS[1]	54.6	62.0	70.6
Natural Gas-fired Combined Cycle	54.5	62.9	74.2
Advanced Nuclear	54.6	61.7	70.5
Geothermal	58.3	60.9	62.4
Biomass	54.5	63.3	74.5
Non-Dispatchable Technologies			
Wind	51.7	55.7	66.4
Wind – Offshore	55.1	62.3	73.7
Solar PV	50.8	73.4	89.6
Solar Thermal	48.2	73.3	82.3
Hydroelectric	54.1	59.9	69.5

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.

Table 4: Difference between levelized avoided costs of electricity (LACE) and levelized costs of electricity (LCOE), 2019 and 2040

Plant Type	Comparison of LACE - LCOE (2012 $/MWh) Average LCOE	Average LACE	Average Difference	Range of DIfferences	
2019					
Dispatchable Technologies					
Conventional Coal	95.6	62.2	-33.5	-48.9	-25.1
IGCC	115.9	62.2	-53.7	-66.1	-43.9
IGCC with CCS	147.4	62.0	-85.4	-104.7	-74.8
Natural Gas-fired					
Conventional Combined Cycle	66.3	62.9	-3.4	-13.7	0.0
Advanced Combined Cycle	64.4	62.9	-1.5	-11.2	0.8
Advanced CC with CCS	91.3	62.9	-28.4	-34.6	-23.7
Advanced Nuclear	86.1	61.7	-24.4	-33.0	-13.0
Geothermal	44.5	60.9	16.4	15.2	18.1
Biomass	102.6	63.3	-39.3	-57.2	-28.5
Non-Dispatchable Technologies					
Wind	80.3	55.7	-24.5	-37.6	-6.3
Wind – Offshore	204.1	62.3	-141.8	-210.1	-107.1
Solar PV	118.6	73.4	-45.2	-96.5	-21.2
Solar Thermal	223.6	73.3	-150.3	-279.3	-83.4
Hydro	84.5	59.9	-24.6	-54.7	-1.0
2040					
Dispatchable Technologies					
Conventional Coal	87.0	76.4	-10.7	-26.3	-5.3
IGCC	99.7	76.4	-23.3	-34.3	-18.2
IGCC with CCS	121.2	77.0	-44.3	-51.8	-38.8
Natural Gas-fired					
Conventional Combined Cycle	81.2	77.7	-3.5	-7.7	-0.4
Advanced Combined Cycle	77.8	77.7	-0.1	-3.9	2.0
Advanced CC with CCS	103.0	77.7	-25.3	-30.0	-15.5
Advanced Nuclear	83.0	76.1	-6.8	-10.1	-0.2
Geothermal	63.5	78.7	47.0	0.5	75.2
Biomass	97.0	78.0	-19.0	-38.4	-9.4
Non-Dispatchable Technologies					
Wind	73.1	70.8	-2.3	-11.8	13.0
Wind – Offshore	170.3	77.4	-92.9	-150.7	-59.3
Solar PV	101.3	89.4	-11.9	-58.4	10.6
Solar Thermal	188.7	96.5	-92.2	-205.1	-36.0
Hydro	84.6	75.3	-9.3	-27.8	11.0

Appendix: Tables for 2040

Table A5. Estimated levelized cost of electricity (LCOE) for new generation resources, 2040

	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2040							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Subsidy[1]**	**Total LCOE including Subsidy**
Dispatchable Technologies								
Conventional Coal	85	52.0	4.2	29.7	1.1	87.0		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	62.8	6.9	28.9	1.1	99.7		
IGCC with CCS	85	77.2	9.8	33.1	1.2	121.2		
Natural Gas-fired								
Conventional Combined Cycle	87	12.5	1.7	65.8	1.2	81.2		
Advanced Combined Cycle	87	13.0	2.0	61.7	1.2	77.8		
Advanced CC with CCS	87	23.4	4.2	74.3	1.2	103.0		
Conventional Combustion Turbine	30	35.2	2.8	107.1	3.4	148.5		
Advanced Combustion Turbine	30	21.8	2.7	87.9	3.4	115.8		
Advanced Nuclear	90	56.7	11.8	13.3	1.1	83.0		
Geothermal	94	43.6	22.9	0.0	1.4	67.8	-4.4	63.5
Biomass	83	39.8	14.5	41.4	1.2	97.0		
Non-Dispatchable Technologies								
Wind	34	56.6	13.3	0.0	3.2	73.1		
Wind – Offshore	37	141.7	22.8	0.0	5.7	170.3		
Solar PV[2]	25	95.3	11.4	0.0	4.0	110.8	-9.5	101.3
Solar Thermal	20	156.2	42.1	0.0	5.9	204.3	-15.6	188.7
Hydroelectric[3]	51	71.2	4.5	7.0	2.1	84.6		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.
[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table A6. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2040

	Range for Total System LCOE (2012 $/MWh)			Range for Total LCOE with Subsidies[1] (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies						
Conventional Coal	78.9	87.0	106.7			
IGCC	90.8	99.7	114.7			
IGCC with CCS	113.0	121.2	135.7			
Natural Gas-fired						
Conventional Combined Cycle	75.8	81.2	94.0			
Advanced Combined Cycle	73.4	77.8	89.4			
Advanced CC with CCS	97.8	103.0	114.8			
Conventional Combustion Turbine	118.8	148.5	172.3			
Advanced Combustion Turbine	108.9	115.8	132.3			
Advanced Nuclear	80.2	83.0	87.6			
Geothermal	54.4	67.8	81.3	50.7	63.5	76.3
Biomass	85.3	97.0	118.8			
Non-Dispatchable Technologies						
Wind	63.4	73.1	82.9			
Wind – Offshore	140.9	170.3	225.3			
Solar PV[2]	86.5	110.8	170.2	79.2	101.3	155.0
Solar Thermal	148.6	204.3	325.6	137.2	188.7	300.5
Hydroelectric[3]	63.6	84.6	122.4			

[1]Levelized cost with subsidies reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992.

[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 32% to 41%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 35% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table A7: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2040

	Range for LACE (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies			
Coal-fired plant types without CCS	72.3	76.4	80.7
IGCC with CCS[1]	72.3	77.0	88.6
Natural Gas-fired Combined Cycle	72.2	77.7	88.4
Advanced Nuclear	72.2	76.1	80.6
Geothermal	75.0	78.7	88.0
Biomass	72.3	78.0	88.7
Non-Dispatchable Technologies			
Wind	65.8	70.8	84.1
Wind – Offshore	71.9	77.4	88.1
Solar PV	83.2	89.4	96.5
Solar Thermal	87.7	96.5	104.4
Hydroelectric	71.0	75.3	88.0

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.