COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND ALL OTHER REQUIRED APPROVALS AND RELIEF	)	Case No. 2017-00179

DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2017

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION 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 whom 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 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

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

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

("FERC"), and in the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit___(SJB-1).

Q. Have you previously presented testimony before the Kentucky Public Service Commission?

A. Yes. I have testified before the Kentucky Public Service Commission ("Commission") in 27 cases over the past thirty years, including numerous Kentucky Power cases. I have also testified in numerous American Electric Power ("AEP") cases in other jurisdictions, including Ohio, West Virginia, Virginia, Indiana, Louisiana, Tennessee, and before the Federal Energy Regulatory Commission.

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

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"). KIUC members take service on a number of Kentucky Power Company ("Kentucky Power" or "Company") rate schedules.

Q. What is the purpose of your testimony?

A. I address four general issues in my testimony. First, I respond to the Company's proposed class cost of service study and the apportionment of the overall revenue increase to rate classes. The Company filed a 12 CP class cost of service study in this case, as it has done in prior cases. While I do not object to the Company's study, I do have concerns about KPCo's proposed apportionment of the revenue increase to rate classes. As I will discuss, the Company has only modestly attempted to reduce the substantial subsidies that currently exist among rate classes. While KIUC appreciates the Company's attempt to reduce subsidies, the proposal to reduce subsidies by only 5% leaves customers on rate IGS (Industrial Generation Service) continuing to pay excessive charges, further reducing the competitiveness of Kentucky manufacturers. The Company has focused significant attention in this case on its economic developments efforts, yet continues to charge its manufacturing customers significant excess charges in the form of "subsidies" paid to other Kentucky Power customers. I will propose an alternative methodology to address the subsidy problem that also is designed to mitigate the impact on residential customers.

I will also address the Company's rate design associated with backup and maintenance service for customers that provide their own on-site generation. Kentucky Power Company does not have a specific, dedicated, backup and maintenance power rate schedule for customers that have their own generation. Under federal law, the Public Utilities Regulatory Policy Act ("PURPA"), electric utilities are required to provide backup and maintenance service. KPCo's affiliate in West Virginia, Appalachian Power Company, proposed such a tariff in 2016 that should serve as a model for KPCo. I will discuss the principles that should govern the design of a backup rate and maintenance service rate and recommend such a rate for KPCo.

Finally, I will respond to the Company's proposal to include PJM Open Access Transmission Tariff ("OATT") costs in the Purchased Power Adjustment tariff. This proposal, if approved, would permit the Company to recover any change in its transmission charges from PJM in an adjustment clause. This would subject customers to potentially large additional cost increases each year, without a full base rate proceeding in which all costs can be evaluated. The proposal is conceptually similar to Kentucky Power's request in its last base rate case (Case No. 2014-00396) in which it requested authority to replace the current Kentucky Commission determined retail transmission rates with FERC regulated PJM OATT rates. The Commission rejected the Company's request in the last base rate KPCo. As I will discuss, the Company's own projections indicate that its OATT transmission costs will increase by millions of dollars over the next 5 years. The cumulative increase over this 5 year period will likely exceed $154 million. I will recommend that this new OATT cost recovery proposal be rejected as well.

Q. Would you please summarize your testimony?

A. Yes.

- The Commission should reject the Company's proposed allocation of the revenue increase in this case that reduces intra-class subsides by 5%. The Company's proposal continues to impose substantial subsidy charges on large industrial customers taking service on Rate IGS. KIUC proposes that the first $5.8 million of any Commission authorized reduction to the Company's requested rate increase be used to fully eliminate the current subsidies paid by Rate IGS customers. Any remaining reduction in the requested revenue increase should be applied to the Company's proposed increases to each rate class following the methodology illustrated in Exhibit__ (SJB-3), which adopts the Company's 5% subsidy reduction approach for all rate classes except IGS.

- The Commission should require the Company to file a backup and maintenance service tariff that follows the cost of service principles required under PURPA and 807 KAR 5:054 Section 7.

- The Company's proposal to recover PJM OATT transmission costs, in excess of the amounts included in base rates, through the Purchased Power Adjustment Tariff should be rejected. This proposal, if adopted, would subject the Company's customers to an estimated $154 million in additional increases over the next 5 years, based on Kentucky Power Company's own projections. The Company's proposal would reduce the scope of regulatory authority by the Commission over KPCo's retail rates and result in a direct pass-through of FERC approved transmission costs without the potential offsetting adjustments that would otherwise be evaluated in a base rate case. This would be an unjustified risk transfer from AEP shareholders to consumers.

II. CLASS COST OF SERVICE AND REVENUE APPORTIONMENT

Q. Have you reviewed the class cost of service study presented by KPCo witness Douglas Buck?

A. The Company has developed a class cost of service study for the test year ending February 2017 using a traditional 12 coincident peak methodology ("12 CP") to allocate production and transmission costs to rate classes. The Company's 12 CP study follows the methodology that KPCo has used for many years. My review of the filed study indicates that it is a reasonable basis on which to assign system costs to rate classes. While I believe that alternative methodologies for production cost allocation that focus more extensively on the summer system peak, which drives the need for capacity on the KPCo system, the 12 CP study filed by the Company is appropriate in this case to assess the reasonableness of class rates, relative to the cost of providing service.

Q. What is the value of a class cost of service study in a base rate case?

A. A class cost of service study is the primary basis to determine how the Company's overall revenue requirement should be assigned to each rate class. The cost study first separates all of the Company's investments, expenses, and revenues into functional categories, representing the key functions provided by the utility, for which it incurs costs. These functions are: production, which includes owned generating units and purchased power contracts; transmission, including PJM expenses incurred by Kentucky Power as part of its membership in the PJM Regional Transmission Organization ("RTO"); distribution, which includes lower voltage substations, primary voltage lines, secondary voltage lines, transformers and meters and customer related costs associated with billing, customer accounting and customer service. Each of these functional cost categories is then allocated to each of the Company's rate classes based on a reasonable measure of cost causation, such as each class's demand at the hour of the monthly system peak (known as 12 coincident peak), kWh energy usage, and the number of customers in the rate class.

Once these costs have been fully allocated, they can be compared to the revenues collected from customers in the rate class. If the costs exceed the revenues for a particular rate class, then that class is said to be "subsidized" by customers in other rate classes. Likewise, if the revenues collected from customers in the rate class exceed its allocated costs, then that rate class is paying subsidies to customers on other rate class. In a base rate case, such as the current KPCo case, there is an opportunity to realign rates to reduce or eliminate such subsidies.

Q. Are the results of a class cost of service study the only factor that the Commission should consider in setting rates for a particular rate class?

A. No. While it is an important factor, it is not the only factor. First, there can be legitimate disagreements on the appropriate methodology that should be used to allocate costs to rate classes. Moreover, such factors as gradualism, economic impact and hardship, rate shock, the impact on competitiveness of industry, and other policy considerations should also be considered by the Commission.

Q. Would you elaborate further on the non-cost of service factors that should be considered in assigning the overall increase to rate classes?

A. The non-cost of service factors can be categorized into two groups: rate shock/gradualism and competitiveness issues. Many Commissions, including this Commission, recognize that there are reasonable limits to how high a rate class's rates can be increased, regardless of the results of a reasonable cost of service study. This is the policy consideration of gradualism, which recognizes that rates should not be excessively increased in a single step, even if there are significant subsidies being received by one or more rate classes. This is especially important in areas where there is currently significant economic hardship already occurring due to general economic conditions.

Q. How should competitiveness be factored into the Commission's decision?

A. Electric rates can be a significant factor in the competiveness of manufacturers that must compete regionally, nationally, and internationally. It is critically important to recognize the impact of ever-increasing electric rates on the ability of large manufacturing customers to continue to operate and to attract new, higher paying manufacturing businesses.

Q. Why is it so important to consider the impact of electric rate changes on the competitiveness of large manufacturers in Kentucky?

A. Maintaining the competitiveness of large manufacturers is critical to Kentucky's economic health. The Company recognizes this and is focusing its economic development efforts on retaining and attracting new manufacturing industries, including coal mining. The Kentucky Cabinet for Economic Development likewise focuses on attracting manufacturers, agribusiness, regional or national headquarters, and non-retail service and technology companies. This issue is addressed in detail by KIUC witness Kornstein. As Mr. Kornstein notes, manufacturing has a very high job multiplier effect. For example, each petroleum refinery job supports 5.5 jobs elsewhere in the region (job multiplier of 6.5). Whereas, each retail job supports only 0.1 jobs elsewhere in the region (job multiplier of 1.1).[1] Additionally, a 2012 study by the Kentucky Energy and Environment Cabinet entitled *"The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices"*

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[1] See Direct Testimony of KIUC witness Barry Kornstein at page 5.

explained the extreme sensitivity of Kentucky manufacturers to electric rate increases and the potential impact of such increases on jobs in the Commonwealth. Among other findings, the study concluded that:

> **Given a 25% forecasted increase in the real price of electricity in Kentucky between 2011 and 2025, this study estimates the Commonwealth will likely lose, or fail to create, approximately 30,000 full-time jobs in the long-term.** Manufacturing establishments were found to be most responsive to changes in electricity prices and can be expected to permanently shed 17,500 full-time jobs. (emphasis added).
>
> ***
>
> Kentucky's electricity-intensive manufacturing economy is threatened by increasing electricity prices. While the price of electricity is only one of several factors influencing industrial location decisions, Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive economy in the United States. In the twenty-first century, the bulwark of the Kentucky economy is clearly manufactured goods—the Commonwealth's single largest source of economic activity.

See Exhibit__ (SJB-2).

Q. What does the Company's 12 CP cost of service study show?

A. The Company's cost of service study clearly show that there is a significant amount of cross-subsidization between rate classes, primarily between the general service/commercial/industrial classes and the residential class. Table 1 below summarizes the current rate of return at present rates, the relative rate of return and the dollar subsidies paid or received by each rate class at present rates.[2]

Table 1
Class Cost of Service Results - Present Rates

Class	Rate of Return %	Relative ROR Index	Current Subsidy*
RS	0.82	0.22	30,457,775
SGS	10.26	2.80	(4,068,230)
MGS	7.98	2.18	(8,161,470)
LGS	7.99	2.18	(7,221,447)
IGS	5.20	1.42	(6,082,510)
PS	5.89	1.61	(971,331)
MW	10.89	2.98	(40,141)
OL	14.78	4.04	(3,443,536)
SL	15.37	4.20	(469,110)
Total	3.66	1.00	0

* Positive value indicates that a subsidy is being received; negative value indicates subsidy is being paid.

[2] Relative Rate of Return ("ROR") is an index formed by the ratio of a rate class rate of return to the system rate of return. If a rate class has a rate of return that is twice the system average, the ROR is 2.0. Alternatively, if a rate class has a rate of return that is negative and the system average is positive (as in this KPCo case), the ROR would be negative.

As can be seen, all of the non-residential rate classes are paying subsidies to the residential class. Rate IGS, which serves customers of 1 MW and above, is currently paying $6.1 million in subsidies. This means that these large customers are paying over $6 million a year more in electric power rates than the KPCo's cost to actually provide the power. In fact, these customers have been paying subsidies in that range (or much higher) since at least 2005.[3]

Q. How is the Company proposing to address these subsidies in its recommended allocation of its proposed base rate decrease to rate classes?

A. As explained by Mr. Buck, KPCo is proposing to reduce these subsidies by 5% in its proposed rates. In other words, the Company is proposing to maintain 95% of the current dollar subsidies paid or received by each rate class. Table 2 below shows the Company's proposed rate class increases and the amount of subsidies that each rate class will continue to pay or receive, once new rates are approved by the Commission. Also shown in Table 2 are the proposed rates of return and relative rates of return for each rate class.

[3] See Baron Direct Testimony in the 2005 and 2009 Kentucky Power rate cases.

Table 2
Class Cost of Service Results at KPCo Proposed Rates

Class	Rate of Return %	Relative ROR Index	Proposed Subsidy*	Proposed Percentage Base Revenue Increase: Total Base	Proposed Percentage Base Revenue Increase: Non-Fuel Base
RS	4.03	0.60	28,934,888	15.99	22.00%
SGS	13.00	1.93	(3,864,819)	9.11	11.47%
MGS	10.84	1.61	(7,753,397)	10.13	13.49%
LGS	10.85	1.61	(6,860,375)	9.27	13.10%
IGS	8.19	1.22	(5,778,385)	8.54	16.98%
PS	8.86	1.32	(922,764)	11.19	15.54%
MW	13.60	2.02	(38,134)	7.75	11.01%
OL	17.30	2.57	(3,271,359)	9.48	11.16%
SL	17.86	2.65	(445,655)	7.09	8.54%
Total	6.73	1.00	0	12.10	18.06%

* Positive value indicates that a subsidy is being received; negative value indicates subsidy is being paid.

Q. Your Table 2 shows two sets of percentage rate increases for each rate class. Would you explain the difference between these two amounts?

A. The percentage increases shown in Table 2 are calculated using the same dollars of revenue increase as a percent of 1) total base revenues and 2) base revenues excluding the base amount of fuel cost. KPCo presents its requested increases as a percent of total base revenues, including the base amount of fuel expense. For the system as a whole, the percentage increase is shown to be 12.1%. However, fuel costs are not at issue in this case; only non-fuel costs are at issue and it is therefore appropriate to view the rate increases for each rate class as a percent on non-fuel base revenues. This is particularly significant when comparing percentage increases for high load factor customer classes, such as Rate IGS vs. the residential class, which is less energy intensive (i.e., has a lower load factor). Since fuel cost represents a significant portion of total base revenues, and higher load factor rate classes have a higher proportion of these fuel costs due to proportionately greater energy usage, it is somewhat misleading to compare the percentage increases without removing fuel expenses from the starting point. The second set of percentage increases does this (non-fuel base revenue increases). Again, it is important to recognize that fuel costs are not at issue in this case. All of the Company's revenue deficiency is due to non-fuel issues.

Q. What do you conclude from Table 2?

A. Despite the fact that Rate IGS customers are currently paying over $6 million in subsidies, the Company is proposing that IGS pay the highest non-fuel base rate increase of any rate schedule other than residential.

Q. Does the Company's proposal adequately address the millions of dollars of subsidies currently paid by the Company's manufacturing customers and other customers on Rate IGS?

A. No. As I showed in Table 1, Rate IGS, where most of the largest manufacturing customers take service, is currently paying $6.1 million in subsidies. That is, these IGS customers are currently paying rates that exceed the costs of providing them service by $6.1 million annually. As I show in Table 2, under the Company's proposal, IGS customers will continue to pay subsidies of $5.8 million, a very small change from the current situation.

Given the sensitivity of these manufacturing customers to competitors in other states and internationally that I discussed earlier, KIUC is recommending an alternative plan to apportion the approved overall revenue increase in this case. Electric power plays a significant role in the competitiveness of most of these Kentucky manufacturers. The Commission should strongly consider this impact, and the corresponding impact on manufacturing employment in Kentucky, and eliminate the subsidies paid by IGS customers. At the same time, I also recommend that the Commission continue to recognize gradualism in the increases assigned to individual rate classes.

Q. Are there any additional factors that the Commission should consider on this issue of allocating the approved revenue increase to rate classes?

A. Yes. As discussed by KIUC witness Kollen, KIUC has played a very significant role in all of the major utility rate cases, and other proceedings that impact customer rates, in Kentucky for many, many years. KIUC member Companies financially support this participation of counsel and experts to evaluate Kentucky Power filings, and other major utilities, before the Commission. As noted by Mr. Kollen, KIUC's direct participation in these proceedings has benefited all customers, not just KIUC member companies, by many hundreds of millions of dollars. All of the cost of this KIUC participation has been paid for by KIUC, even though the benefits are distributed to all customers proportionally. In effect, this substantial KIUC participation in regulatory proceedings, fully paid for by KIUC members, amounts to an additional subsidy that is provided to other customers on the system.

Q. Would you describe your specific proposal?

A. The Company has requested an overall revenue increase in this case of $60.4 million. Based on experience, it is unlikely that the Commission will approve the full amount of the Company's revenue increase request. As discussed by KIUC witness Lane Kollen, KIUC is recommending an overall revenue increase in this case of $13.4 million, which is a $47 million reduction from the Company's filed requested increase.

My proposal is to use the first $5.8 million of any Commission authorized reduction in the Company's $60.4 million increase to fully eliminate the Rate IGS subsidy. Under the Company's proposal, existing rate class subsidies paid and received are reduced by 5% for each rate class. As shown in Table 2, the Company's proposal would result in Rate IGS customers continuing to pay an additional $5.8 million in subsidies, over and above the costs of providing electric power to these customers. This $5.8 million is the additional subsidy reduction that I am proposing for Rate IGS. This would put Rate IGS at cost of service.

Q. Will this $5.8 million subsidy reduction be charged to customers on other rate classes?

A. No. Since I am using the first $5.8 million of any Commission authorized reduction from the Company's $60.4 million requested increase, all other customer classes will not be impacted, relative to the Company's proposed increases in its filing. All other rate classes (other than Rate IGS) will include the effect of the Company's 5% subsidy reduction in proposed rates; my proposal simply uses the proceeds from a Commission adjustment to the overall increase to further reduce the subsidies paid by Rate IGS (i.e., the remaining Rate IGS subsidies are eliminated, while the subsidies for all other rate classes are reduced by the KPCo proposed 5% amount).

Q. What is the next step in your proposal?

A. Assuming that there is an additional Commission authorized reduction from the Company's $60.4 million increase request, this would be used to reduce the Company's proposed revenue increases to all rate classes, including Rate IGS, which is still receiving an increase even after all of its subsidies are removed. This second step reduction would be spread uniformly based on the increases allocated to each rate class at the full $60.4 million increase. Assuming that the Commission authorized reduction exceeds $5.8 million, each rate class would receive a reduction from the Company's proposed increases. Rate IGS would receive an increase reflecting full cost of service. Again, at the end of this step, the rate increase to each rate class (other than Rate IGS) would continue to reflect the KPCo 5% subsidy reduction. Rate IGS would reflect a full elimination of its subsidy payments.

Q. **Would your proposal only benefit KIUC members on Rate IGS?**

A. No. Based on data from the Company's 2016 FERC Form 1, there are 73 customers on Rate IGS; 21 of these customers are commercial customers, 52 are industrial. KIUC has 4 members on Rate IGS. Other customers on Rate IGS include hospitals, large commercial customers, such as so-called "big box" stores and others. While Rate IGS is not comprised of only large manufacturers, all large manufacturers are on Rate IGS.

Q. **Can you provide an illustration of how your methodology would work, assuming that the Commission reduced the Company's overall $60.4 million revenue increase in this case?**

A. Yes. I have developed two alternative illustrations, assuming that the Commission reduced the Company's requested $60.4 million increase by $20 million and $45 million (KIUC witness Kollen has recommended adjustments in the range of $45 million). Tables 3 and 4 summarize the results of these alternative scenarios. Baron

Exhibit__(SJB-3), pages 1 and 2, present the detailed support for the development of these rate class increases.

Table 3
KIUC Proposed Revenue Allocation Illustration
($20 Million Reduction in KPCo Requested Revenue Increase)

Class	Current Revenue	Proposed Increase	Proposed Percentage Base Revenue Increase	
			Total Base	Non-Fuel Base
RS	215,744,788	25,519,755	11.83	16.27
SGS	18,576,461	1,252,039	6.74	8.48
MGS	53,330,702	3,996,436	7.49	9.98
LGS	51,375,193	3,522,442	6.86	9.69
IGS	138,769,640	4,492,765	3.24	6.44
PS	11,504,476	952,123	8.28	11.49
MW	194,343	11,147	5.74	8.14
OL	8,231,794	576,965	7.01	8.25
SL	1,407,108	73,765	5.24	6.31
Total	499,134,505	40,397,437	8.09	12.08

* Percentage increase on base revenues, excluding riders.

Table 4
KIUC Proposed Revenue Allocation Illustration
($45 Million Reduction in KPCo Requested Revenue Increase)

Class	Current Revenue	Proposed Increase	Proposed Percentage Base Revenue Increase	
			Total Base	Non-Fuel Base
RS	215,744,788	9,726,826	4.51	6.20
SGS	18,576,461	477,213	2.57	3.23
MGS	53,330,702	1,523,237	2.86	3.80
LGS	51,375,193	1,342,575	2.61	3.69
IGS	138,769,640	1,712,412	1.23	2.45
PS	11,504,476	362,901	3.15	4.38
MW	194,343	4,249	2.19	3.10
OL	8,231,794	219,909	2.67	3.15
SL	1,407,108	28,115	2.00	2.41
Total	499,134,505	15,397,437	3.08	4.60

* Percentage increase on base revenues, excluding riders.

III. RATE DESIGN ISSUES

Q. Do you have any concerns with the Company's proposed rate design for rate schedules on which KIUC members take service?

A. Yes. While I have not identified any problems with the Company's proposed standard rate schedules, such as Rate IGS, I do have a problem with the lack of any

Backup Service and Maintenance Service rate that would serve large customers who have their own on-site generation. The Public Utilities Regulatory Policy Act ("PURPA") requires electric utilities to offer backup power and maintenance service rates for Qualifying Facilities ("QFs").[4] Backup and maintenance rates provide service to customers that require power to serve their load in the event that the customers own generation is forced out or is out due to scheduled maintenance of the customer's generation.

Q. Does the Commission require electric utilities in Kentucky under its regulation to offer such backup and maintenance rates?

A. Yes, 807 KAR 5:054 Section 7 has similar language to PURPA and requires utilities to offer backup and maintenance service rates to QFs.

Q. Does KPCo have a backup and maintenance service rate available to large customers?

A. Not really. The only reference to a backup or maintenance power rate that appears in the Company's tariffs is a single paragraph included in Rate IGS. The tariff provision is as follows:

[4] CFR §292.305.

<u>SPECIAL TERMS AND CONDITIONS.</u>

*
*
*

> This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph '"Minimum Charge" above.

The Company's backup service is simply the rate on the regular IGS tariff, not a specific backup rate.

Q. **Does the Company have a maintenance service rate that would provide power to customers when the customer's own generation is unavailable due to scheduled maintenance?**

A. No. There does not appear to be any such tariff available, other than taking service on the standard IGS rate schedule. Customers who have their own generation will require such maintenance service during periods when the customer's own generation is out for scheduled or planned maintenance. Typically, in such circumstances, the customers would coordinate with the utility to schedule maintenance during a period when it would not cause a capacity burden for the supplying utility.

Q. Does federal law (PURPA) and the Kentucky Commission's rules require that back-up and maintenance service be provided by a utility?

A. Yes. PURPA states that a utility must offer back-up and maintenance service for Qualifying Facilities. Specifically, §292.305 Rates for Sales requires the following:

> (b) *Additional services to be provided to qualifying facilities.*
>
> (1) Upon request of a qualifying facility, each electric utility shall provide:
> (i) Supplementary power;
> (ii) Back-up power;
> (iii) Maintenance power; and
> (iv) Interruptible power.
>
> (2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:
> (i) Impair the electric utility's ability to render adequate service to its customers; or
> (ii) Place an undue burden on the electric utility.
>
> (c) ***Rates for sales of back-up and maintenance power.*** The rate for sales of back-up power or maintenance power:
>
> (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

Similarly, in Kentucky, 807 KAR 5:054. Small power production and cogeneration, Section 7 requires that utilities provide back-up and maintenance power to QFs. Section 7 is as follows:

> (7) Additional services to be provided to qualifying facilities. Upon request by a qualifying facility each electric utility shall provide supplementary power, back-up power, maintenance power, and interruptible power. The commission may waive this requirement if the electric utility demonstrates that compliance with it would impair its ability to render adequate service to its other customers or would be unduly burdensome.

Q. Do you believe that the Company's "Special Terms and Conditions" paragraph in Rate IGS meets the requirements of PURPA §292.305 and 807 KAR 5:054 Section 7?

A. No. Though I cannot offer a legal opinion on this issue, from a ratemaking standpoint, the provision in Rate IGS for back-up power does not address the requirements of state or federal law. To the contrary, the provision seems intended to thwart self-generation. As such, it is not a reasonable cost based rate.

Q. Should the Company be required to offer a back-up and maintenance service rate?

A. Yes. An appropriate approach would be to use the methodology that KPCo witness Vaughan proposed in a recent case filed by KPCo affiliates Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo"). Baron Exhibit__(SJB-4) contains a copy of Mr. Vaughan's testimony in West Virginia Case No. 15-1734-E-T-PC on behalf of APCo/WPCo. Also included in

Exhibit__(SJB-4) is a copy of a proposed Back-up and Maintenance Service tariff that Mr. Vaughan recommended. Though that APCo/WPCo case was subsequently withdrawn by the Companies, Mr. Vaughan's back-up power methodology, as presented in WV Case No. 15-1734-E-T-PC, is a reasonable approach to back-up power rate design.

Q. How did Mr. Vaughan design the back-up power rate?

A. He based the rate on a probability adjusted production demand rate using the standard tariff. The probability is the expected percentage amount of time that a standby customer expects to have its own generation "forced-out" during the year. For example, if a back-up power customer expects that its own generation will be forced-out 10% of the time, the customer would require the equivalent of full service, 10% of the time. Mr. Vaughan then applied a 10% factor to the unit production demand cost/kW for two large customer rate classes. The unit production demand cost/kW differs from the actual rate schedule demand charge to the extent that there may be some demand costs recovered in the energy charge of a rate. Essentially, given the very low probability that a back-up customer will actually require capacity from the Company, the cost to serve that back-up customer will be only a fraction of the regular tariff charge. This is easy to see if it is assumed that there are multiple back-up customers, each having forced outages independent of each other. Clearly, the total capacity required to meet all of this back-up load would only be a fraction of the maximum demands that all back-up customers could place on the system. In fact, this conceptual underpinning is required in PURPA, as I showed above [see §292.305 (c)(1)].

Q. Do you agree with APCo's probability adjusted back-up rate design methodology?

A. Yes. I believe that this method reasonably calculates the cost to serve back-up load.

Q. Can you provide an illustration of this type of back-up rate for KPCo?

A. Yes. While the actual rate design would be best on the detailed functional demand costs for KPCo large demand metered rates, I have calculated approximate back-up rates for Rate IGS using the APCo/AEP methodology. For this purpose, I have used the Company's proposed Rate IGS demand charge of $15.56/kW month as the starting point for the back-up rates. Following the AEP methodology, a customer that requires up to 876 hours per year of back-up service (corresponding to a 10% cogeneration equipment forced outage rate) would pay a monthly back-up charge of $1.56/kW. If the customer required up to 1,314 hours per year of back-up service (15% forced outage rate on customer's generation equipment), the monthly back-up rate would be $2.33/kW; for a 20% forced outage rate requirement, the monthly back-up rate would be $3.11/kW. In addition, the customer would pay the standard Rate IGS energy charge for any back-up power actually used.

Q. How did APCo/AEP develop a maintenance service rate?

A. Mr. Vaughan calculated a maintenance service rate using the standard industrial tariff energy charge (including fuel and purchased energy), plus a portion of the demand charge.

Q. Did you participate in WV Case No. 15-1734-E-T-PC?

A. Yes. I supported Mr. Vaughan's back-up power rate design and methodology, though I disagreed with his approach regarding a maintenance service rate. My disagreement with his proposed maintenance service rate was that it should not include any demand or capacity charge, since this was already being charged through the monthly reservation charge. Other than that, Mr. Vaughan's approach in the APCo/WPCo case would be an appropriate basis for designing a similar back-up and maintenance service tariff for Kentucky Power.

Q. What is you recommendation on this issue?

A. Consistent with the requirements of PURPA and 807 KAR 5:054, KPCo should be required to develop and offer a specific back-up and maintenance service tariff that follows the methodology used by Mr. Vaughan in his APCo/WPCo testimony. The back-up and maintenance service rate design should follow the methodology presented in the APCo/WPCo case, except that there should be no additional capacity charge component for maintenance service.

Q. Have you identified any additional rate design or tariff issues in this case?

A. Yes. On June 12, 2017, the Company filed a case (2017-00231) requesting approval to restructure its customer bills. In an Order issued on July 17, 2017, the Commission consolidated the bill restructure case into this base rate case. In its bill restructuring case, KPCo proposes to consolidate several of the 13 billing line items that may currently appear on commercial and industrial customer bills. Under the Company's proposal, the Fuel Adjustment Clause, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, and State Sales Tax would continue to be displayed as individual billing line items, if applicable. But all other billing line items would be combined into a single "Rate Billing" line item.

Q. Do you have any specific problems with the Company's proposal?

A. Yes. Much of the Company's motivation for restructuring its bills appears to be based on the concerns of smaller customers, particularly residential customers. My concern focuses on the impact of the Company's proposal on large, energy-intensive industrial customers. These customers specifically track cost trends associated with each of the billing line items over time. This information is helpful for budgeting purposes and facilitates customer inquiries into large cost spikes or drops associated with particular billing line items. If the Commission were to consolidate several of the billing line items into a single generic "Rate Billing" line item, large customers would lose access to this valuable information.

Q. What do you recommend with respect to the proposed billing line item consolidation?

A. I recommend that the Commission reject Kentucky Power's proposed billing line item consolidation for the commercial and industrial customer bills. I offer no opinion as to the consolidation of billing line items on residential customer bills.

IV. RECOVERY OF PJM TRANSMISSION COSTS IN THE PPA TARIFF

Q. Would you please summarize your understanding of the Company's proposal to recover certain PJM related transmission expenses through the Purchased Power Adjustment tariff?

A. In a proposal conceptually similar to the Company's proposal in its 2014 base rate case, KPCo is requesting that it be permitted to recover PJM Open Access Transmission Tariff ("OATT") related transmission expenses, in excess of the test year level, in the Purchased Power Adjustment ("PPA") Tariff. Effectively, the Company's proposal would permit it collect PJM transmission expenses through an automatic adjustment clause (in this case, the PPA Tariff).

Q. What type of PJM OATT costs is the Company requesting for this PPA Tarff recovery?

A. The proposal would permit KPCo to recover all of its Load Serving Entity ("LSE") transmission costs through the PPA Tariff. This includes the following costs:

- Network Integration Transmission Service (NITS)
- Transmission owner scheduling control and dispatch service (TO)
- Regional Transmission Expansion Plan costs (RTEP)
- Point-to-Point transmission service (PTP)
- RTO Startup Costs (RTO)

The test year level of all of these PJM LSE costs is $74 million. This amount would be included in base rates in the Company's proposal. Of these costs, the largest are the NITS charges (test year level of $64 million), which represents the Company's share of AEP Zonal transmission revenue requirements associated with paying for lines, substations and related costs and, RTEP (test year level of $9.8 million), which represents the Company's share of the AEP share of incremental transmission investment that is incurred by PJM to meet the reliability requirements for the entire RTO. These costs are allocated to PJM zones, including the AEP zone, based on a complex allocation process defined in the PJM OATT and approved by the Federal Energy Regulatory Commission ("FERC").

Under the Company's proposal, the test year level of these PJM LSE expenses will be included in base rates. Once new base rates are approved and effective, future levels of the PJM LSE expenses in excess of the test year level would be recoverable in the PPA Tariff. In the event that the future level of expenses are less than the test year amount, there would be a credit in the PPA Tariff.

Q. Has the Company provided an estimate of the expected level of these PJM LSE expenses?

A. Yes. In response to KIUC 1-67, KPCo provided estimates of its projected levels of PJM transmission expenses for the period 2018 to 2022. These are shown in Table 5 below. Also shown in Table 5 is the test year level that would be included in base rates. The difference is shown on the last row and represents the amount that would be recoverable in the PPA Tariff.

Table 5
KPCO Forecasted PJM LSE OATT Charges

Account	2018	2019	2020	2021	2022
PJM Trans Enhancement Charge	1,558,691	1,675,475	1,846,538	2,232,040	2,503,778
PJM NITS Expense - Affiliated	31,834,038	38,913,916	48,217,220	61,160,008	73,421,256
Affiliated PJM Transmission Enhancement Expense	3,473,945	3,743,206	3,814,712	3,892,578	3,821,926
PJM Point to Point Trans Svc	(556,049)	(556,049)	(556,049)	(556,049)	(556,049)
PJM Affiliated Trans NITS Cost	43,873,682	47,331,309	50,248,209	51,552,464	49,815,111
PJM Affiliated Trans TO Cost	443,763	441,831	438,877	438,329	437,372
Affiliated PJM Transmission Enhancement Cost	1,785,824	1,730,295	1,671,016	1,591,318	1,469,466
Total	82,413,894	93,279,982	105,680,523	120,310,689	130,912,861
Test Year Amount	74,038,517	74,038,517	74,038,517	74,038,517	74,038,517
PPA Tariff Charge	8,375,377	19,241,465	31,642,006	46,272,172	56,874,343

As can be seen in Table 5, the Company's proposal is expected to increase customer charges in the PPA Tariff by $8.4 million in 2018, escalating to $56.9 million in 2022. If the KPCo proposal is adopted, the Company's customers would pay over $154 million more over the next 5 years, assuming no base rate case. Clearly, this proposal will have a very significant impact on rates. Even if it is assumed that the Company would file another base rate case in 2019 (two years from the current filing), with rates effective in 2020, customers will end up paying about $27.5 million more in 2018 and 2019 under the Company's proposal, compared to the current recovery method.

Q. Have these costs been increasing historically for the Company?

A. Yes. Table 6 below shows the same PJM LSE costs assigned to KPCo for the period 2013 through 2016. This information was provided in response to KIUC 1-13. As can be seen, the PJM charges have increased by about $28 million during the past 4 years. While this represents a substantial increase, it is not as large as the Company is projecting for the next 4 to 5 years. Putting together the historic actual and projected information, the Company's transmission costs will have increased from $42.4 million in 2013 to $130.9 million in 2022.

Table 6
PJM LSE OATT Expenses (2013 through 2016)

	Item/FERC Account	2,013	2,014	2,015	2,016
4561005	PJM Point to Point Trans Svc	($621,335)	($683,895)	($600,207)	($556,049)
4561002	RTO Formation Cost Recovery	$140,097	$141,915	$108,909	$190,937
4561035	PJM Affiliated Trans NITS Cost	$35,845,588	$37,449,828	$42,019,312	$43,759,831
4561036	PJM Affiliated Trans TO Cost	$504,742	$674,967	$699,785	$588,030
4561060	Affil PJM Trans Enhancmnt Cost	$280,267	$592,448	$711,346	$802,928
5650012	PJM Trans Enhancement Charge	$3,487,776	$4,364,736	$5,543,065	$5,651,726
5650016	PJM NITS Expense - Affiliated	$2,651,959	$6,412,282	$11,018,159	$16,666,617
5650019	Affil PJM Trans Enhncement Exp	$130,031	$516,618	$1,767,331	$3,465,752
	Total	$42,419,125	$49,468,899	$61,267,700	$70,569,772

Q. Should the Company's proposal to recover PJM LSE costs through the PPA Tariff be rejected?

A. Yes. As I indicated, this proposal is similar to the Company's proposal in Case No. 2014-0396. In that case, the Company proposed to recover 100% of its transmission expenses in a separate adjustment clause, and to eliminate any reconciliation with retail ratemaking adjustments. If effect, under the prior proposal, KPCo would only charge the FERC approved PJM OATT rates. In this case, the Company is modifying its prior proposal, but the essential elements are the same. That is, all new, incremental charges imposed under the FERC tariff would automatically be collected from customers. As I showed in Table 5, KPCo's own projection is that these new costs would likely exceed $154 million over the next 5 years.

Q. Why do you oppose the Company's proposal?

A. There are two reasons. First, the Company's proposal will significantly limit the current Kentucky Commission jurisdiction and ratemaking authority over retail KPCo transmission charges. Absent a base rate case, KPCo charges will increase by millions of dollars each year, based on FERC ratemaking.

The second reason to reject the Company's PJM LSE proposal is that it will likely substantially increase costs to Kentucky customers in future years, based on the Company's own projections. Under the current regulatory framework, KPCo must file a base rate case to recover increases in transmission expense. The recovery of

PJM LSE costs through the PPA Tariff would permit an annual adjustment in a substantial amount of costs, based only on FERC regulatory approval. In fact, it could increase transmission rates through a rider even if it were over-earning. On the other hand, in a base rate case, other KPCo revenue requirements can be evaluated to determine if there are offsetting cost decreases. With the PPA Tariff recovery proposal, PJM LSE transmission costs are considered only as a single issue. Since the Company does not typically file base rate cases each year, it is likely that customers would not be subject to the same level of transmission cost increases under the current regulatory framework as they would be under the Company's PJM LSE proposal. In a base rate case, the Kentucky Commission can evaluate all of the Company's costs, including these PJM LSE transmission costs. Under the PPA Tariff proposal, a substantial portion of the Company's costs would simply be passed on from the FERC, without any potential for offsetting adjustments. Also, because the Company is not proposing to include potential increases in its share of AEP transmission owner revenues that would likely increase over time as investment increases, the Company's proposal might result in excessive earnings.

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 2nd day of October 2017.

Jessica K. I

Notary Public

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND ALL OTHER REQUIRED APPROVALS AND RELIEF	)	Case No. 2017-00179

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2017

COMMONWEALTH OF KENTUCKY

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EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2017

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron graduated from the University of Florida in 1972 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 forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

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

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

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

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

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

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

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

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

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

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

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
	Sub 391		Industrials (CIGFUR III)		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.
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.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and 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.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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.
8/91	E-7, 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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	Federal	Louisiana Public	Gulf States	Merger of GSU into Entergy

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Date	Case	Jurisdict.	Party	Utility	Subject
	21000 ER92-806-000 (Rebuttal)	Energy Regulatory Commission	Service Commission Staff	Utilities/Entergy agreement.	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.
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 &	Proposals to address competition in telecommunication markets.

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				Telegraph Co.	
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.
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	US Bank-ruptcy	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths

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Date	Case	Jurisdict.	Party	Utility	Subject
	No. 94-11474	Court Middle District of Louisiana			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
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	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735	LA	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WV	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	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
09/00	00-1178-E-T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power 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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Date	Case	Jurisdict.	Party	Utility	Subject
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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Date	Case	Jurisdict.	Party	Utility	Subject
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	WV	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.
03/06	05-1278-E-PC -PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Retail cost of service, rate design.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A- 05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
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
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

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Date	Case	Jurisdict.	Party	Utility	Subject
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
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	Kentucky Power Company	Cost of service, rate design,

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Date	Case	Jurisdict.	Party	Utility	Subject
			Utility Customers, Inc.		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
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	WV	West Virginia	Mon Power Co.	Energy Efficiency/Demand Reduction

Expert Testimony Appearances
of
Stephen J. Baron
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Date	Case	Jurisdict.	Party	Utility	Subject
	E-P-T		Energy Users Group	Potomac Edison Co.	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	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
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	Entergy Services, Inc.	System Agreement Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission	and the Entergy Operating Companies	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/11-1775 -E-P	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
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-GI	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

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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-GI	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
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
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Interruptible load
5/15	15-0301-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/15	15-0303-	WV	West Virginia Energy	Appalachian Power	Energy Efficiency/Demand Response

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
	E-P		Users Group	Company, Wheeling Power Co.	
6/15	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/15	D2015-6.51	MT	Montana Large Customer Group	Montana Dakota Utilities Co.	Class Cost of Service, Rate Design
11/15	15-1351-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
3/16	EL01-88 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Bandwidth Tariff
5/16	16-0239-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
6/16	E-01933A-15-0322	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
6/16	16-00001	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
6/16	14-1297-EL-SS0-Rehearing	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
06/16	15-1734-E-T-PC	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Demand Response Rider
7/16	160021-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/16	16AL-0048E	CO	CF&I.Steel LP Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
7/16	16-0403-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Response
10/16	16-1121-E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/16	16-0395-EL-SSO	OH	Ohio Energy Group	Dayton Power & Light	Electric Security Rate Plan

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
11/16	EL09-61-004 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/16	1139	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design
1/17	E-01345A-16-0036	AZ	Kroger	Arizona Public Service Co.	Cost of Service, Rate Design
2/17	16-1026-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Purchase Power Agreement
3/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/17	16-1852	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
7/17	17-00032	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Vegetation Management Cost Recovery
8/17	17-0631-E-P	WV	West Virginia Energy Users Group	Monongahela Power Co.	Electric Energy Purchase Agreement
8/17	17-0296-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation Resource Asset Transfer

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND ALL OTHER REQUIRED APPROVALS AND RELIEF	)	Case No. 2017-00179

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2017

The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices

Aron Patrick

Kentucky Energy and Environment Cabinet
Department for Energy Development and Independence

October, 2012

energy.ky.gov

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Executive Summary

Kentucky's low electricity prices have fostered the single-most electricity-intensive manufacturing economy in the United States, a manufacturing economy that is now threatened by future electricity price increases. This study builds upon the notion that low energy costs are a catalyst for commercial growth by quantifying the specific vulnerability of the largest economic sectors of the Commonwealth, in terms of total employment, to future electricity price increases. Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, this study modeled the responsiveness of employment across the United States to changes in the price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing, retail services, hospitality, healthcare, and government. *Elasticities* were developed for each of these economic sectors to calculate changes in employment, given a specific change in the price of electricity, and can be generally applied to the 48 contiguous United States.

Given a 25% forecasted increase in the real price of electricity in Kentucky between 2011 and 2025, this study estimates the Commonwealth will likely lose, or fail to create, approximately 30,000 full-time jobs in the long-term. Manufacturing establishments were found to be most responsive to changes in electricity prices and can be expected to permanently shed 17,500 full-time jobs. The other largest employment sectors in Kentucky, retail stores, restaurants, and hotels, were less than half as responsive as the manufacturing sector to increasing electricity prices, and combined, can be expected to fail to create 12,500 full-time jobs. However, in the fourth and fifth largest employment sectors, healthcare and government, no statistically significant relationship could be identified between electricity prices and total employment.

While total employment in Kentucky is expected to continue to rise in other sectors, **the Commonwealth should develop strategies to mitigate vulnerability to energy price increases, volatility, and risk exposure. Additionally, Kentucky should maintain focus on education and workforce development in emerging industries that are less reliant on energy-intensive manufacturing processes.** These forecasted electricity price increases, in addition to the current trend towards off-shoring and automation of manufacturing processes, have the potential to transform the economies of manufacturing states like Kentucky.

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The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices

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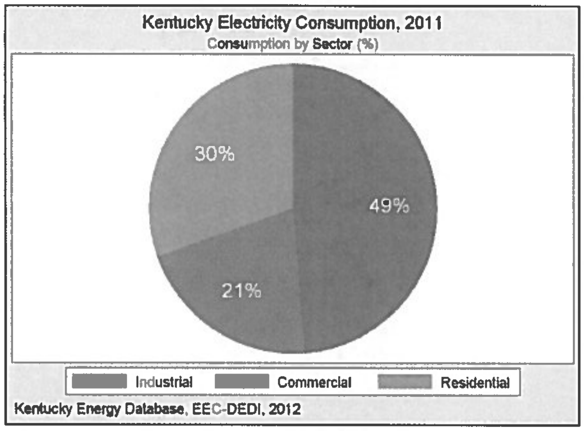
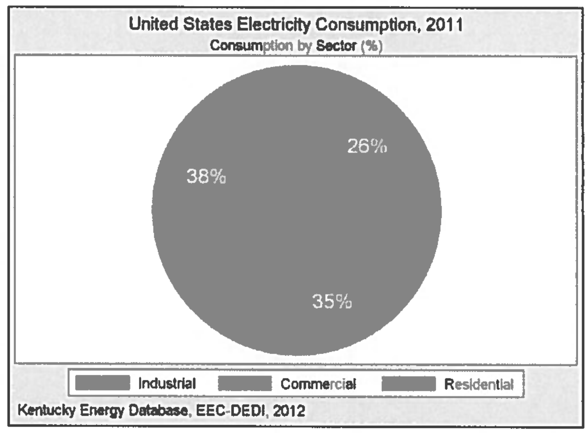
Kentucky's Energy-Intensive Economy

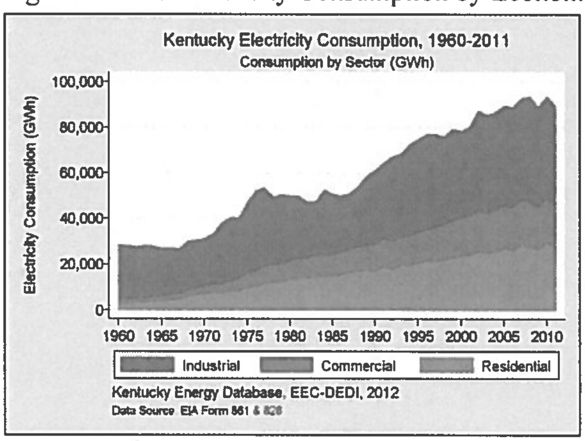
In 2011, 49% of all electricity consumed in Kentucky went to industrial users, compared with 26% for the United States as a whole, as illustrated in Figures 1 and 2 below. The reason for this is obvious—industries requiring large amounts of electricity for production have an incentive to locate in states where they can anticipate that electricity costs will remain low. The industrial nature of Kentucky's electricity load is by no means a recent development. Ever since the first power plants were built in the Commonwealth, most of the electricity produced went to large factories. Over the past 50 years for which there is reliable data, industrial users have consumed an average of 60% of all electricity generated in Kentucky annually, as illustrated in Figure 3 below. These proportions for the United States as a whole have historically been far more balanced, as illustrated in Figure 4 below.

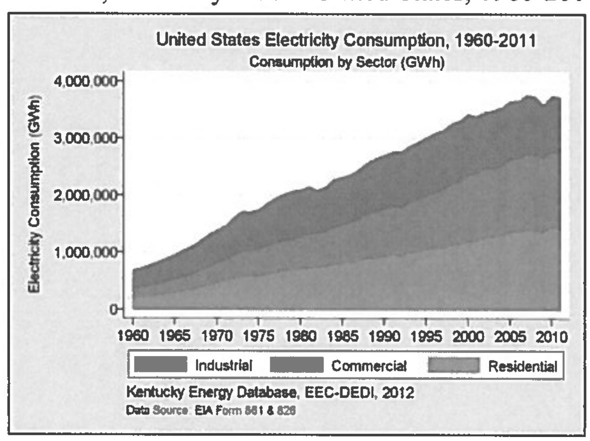
Figures 1 & 2: Electricity Consumption by Economic Sector, Kentucky vs. the United States, 2011





Figures 3 & 4: Electricity Consumption by Economic Sector, Kentucky vs. the United States, 1960-2011





Coal has historically provided the Commonwealth both low-cost electricity and energy security. Nominal electricity prices in Kentucky have increased since 1970 at about 2% annually, which is less than the average rate of inflation during this same period. When adjusted for inflation,[1] as illustrated in Figure 5 on page 3, real electricity prices actually fell in Kentucky from 1980 to 2003, and have risen over the past decade with increases in the price of all fossil fuels. Since 1992, Kentucky has maintained one of the lowest four electricity prices in the nation, running neck and neck with the coal and hydroelectric states of Idaho, Wyoming, Washington, and West Virginia.

Figure 6 on page 3 illustrates that Kentucky is home to the most electricity-intensive economy in the United States. Simply stated, *this means that Kentucky industries use more kilowatt-hours of electricity to produce one dollar of GDP than any other state and are, therefore, more sensitive to changes in electricity prices than any other state.*

In 2009, the most-electricity-intensive sectors nationally were aluminum smelting, iron & steel mills, paper mills, chemical production, and glass manufacturing, which required on average between 0.5 and 4.5 kilowatt-hours of electricity to produce $1 worth of goods. At current Kentucky industrial electricity prices, each dollar of shipments from these industries required between $0.025 and $0.222 worth of electricity. In other words, up to a quarter of total revenues in these industries go to electricity costs. In Kentucky, the most-intensive of these manufacturing processes, which require more than 0.5 kilowatt-hours of electricity to produce $1 of goods, directly contributed $5 billion, or 3.2%, to the Commonwealth's total 2009 GDP and employed 12,685 Kentuckians.[2] The national average electricity-intensity of each NAICS manufacturing sector present in Kentucky is summarized in Table 1 on page 4 along with the total number of employees and the contribution of each industry to Kentucky's 2009 State GDP based on data provided by the U.S. Census Bureau's Annual Survey of Manufactures and the U.S. Bureau of Economic Analysis.[3] This table provides an approximate rank ordering of sensitivity to electricity prices between types of manufacturing operations present in Kentucky.

Figure 5: Total Real Electricity Prices, 1970-2010, Kentucky vs. the United States

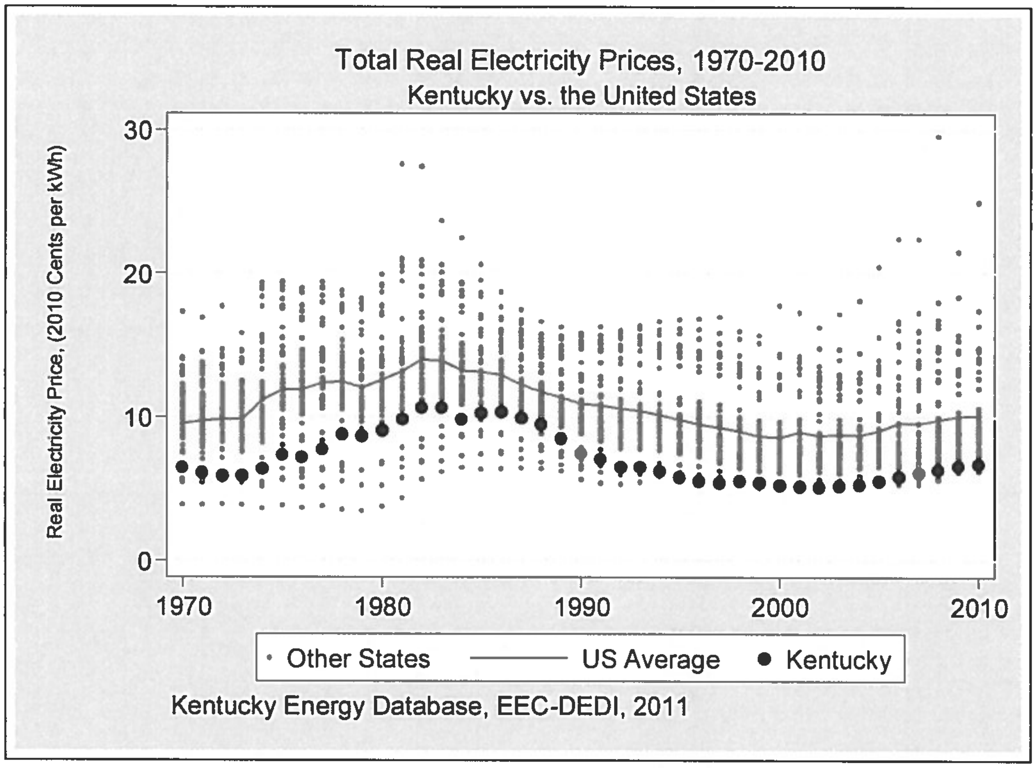


Figure 6: Total Electricity Intensity of Production, 1963-2010, Kentucky vs. the United States

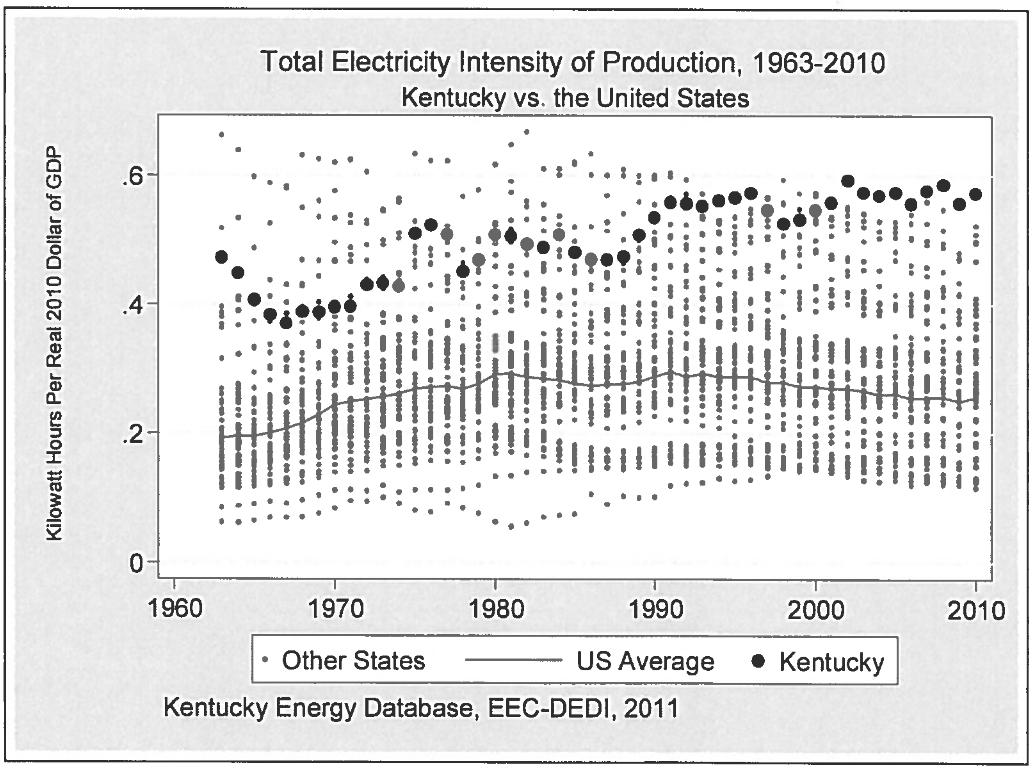


Table 1: National Manufacturing Sector Electricity-Intensity and Kentucky Employment by NAICS, 2009

NAICS 4	NAICS Description	National Electricity Intensity of Production (kWh per $ of Shipment)	Kentucky Average Workers	Kentucky Production Worker Hours (1,000)	Kentucky Value added ($1,000)
3313	Aluminum Production & Processing	4.37313	3,482	6,930	1,083,373
3311	Iron & Steel Mills & Ferroalloy	1.57640	2,954	6,083	232,537
3221	Pulp, Paper, & Paperboard Mills	1.11598	1,192	2,382	1,142,732
3251	Basic Chemical	0.71269	3,043	6,000	2,245,950
3272	Glass & Glass Product	0.60508	2,015	4,151	287,908
3315	Foundries	0.39152	1,595	3,403	104,152
3252	Resin, Syn Rubber, & Artificial Syn Fibers & Filaments	0.35947	1,845	3,799	544,965
3273	Cement & Concrete Product	0.34890	1,688	2,996	236,878
3279	Other Nonmetallic Mineral Product	0.32072	755	1,352	82,074
3132	Fabric Mills	0.30503	857	1,299	
3328	Coating, Engraving, Heat Treating, & Allied Activities	0.29064	730	1,434	62,744
3261	Plastics Product	0.28636	9,552	19,369	1,369,277
3121	Beverage	0.23187	1,941	3,563	
3211	Sawmills & Wood Preservation	0.21894	1,743	3,387	173,367
3359	Other Electrical Equipment & Component	0.21885	1,237	2,283	256,187
3321	Forging & Stamping	0.21571	1,462	2,883	200,502
3262	Rubber Product	0.21049	1,161	2,209	130,931
3116	Animal Slaughtering & Processing	0.17398	8,233	17,208	1,126,612
3114	Fruit & Vegetable Preserving & Specialty Food	0.16088	3,214	6,478	466,909
3118	Bakeries & Tortilla	0.16008	4,018	6,983	740,444
3222	Converted Paper Product	0.15944	5,636	10,950	1,167,297
3344	Semiconductor & Other Electronic Component	0.15703	707	1,315	44,721
3326	Spring & Wire Product	0.14747	2,359	4,496	246,093
3363	Motor Vehicle Parts	0.14719	16,660	31,037	2,942,269
3259	Other Chemical Product & Preparation	0.14596	915	1,965	184,767
3231	Printing & Related Support Activities	0.14519	8,092	15,155	846,289
3327	Machine Shops, Turned Product, & Screw, Nut, & Bolt	0.14463	2,772	5,570	336,332
3329	Other Fabricated Metal Product	0.14187	2,699	4,948	456,340
3219	Other Wood Product	0.14074	5,764	10,705	413,340
3324	Boiler, Tank, & Shipping Container	0.13796	885	1,701	196,781
3336	Engine, Turbine, & Power Transmission Equipment	0.13598	1,209	2,138	127,183
3335	Metalworking Machinery	0.13253	1,331	2,250	139,843
3241	Petroleum & Coal Products	0.13014	740	1,456	
3371	Household & Institutional Furniture & Kitchen Cabinet	0.12103	1,597	2,765	
3115	Dairy Product	0.11755	1,531	3,136	321,496
3364	Aerospace Product & Parts	0.11584	1,257	2,322	420,386
3372	Office Furniture (Including Fixtures)	0.11478	1,017	2,017	
3399	Other Miscellaneous	0.10128	2,006	3,913	325,240
3352	Household Appliance	0.09877	1,576	2,858	
3339	Other General Purpose Machinery	0.09456	3,307	6,293	758,199
3119	Other Food	0.09371	1,570	2,906	579,615
3255	Paint, Coating, & Adhesive	0.09362	907	1,777	537,129
3366	Ship & Boat Building	0.09142	980	2,081	
3334	Ventilation, Heating, Ac, & Commercial Refrigeration	0.08948	2,071	3,765	376,925
3323	Architectural & Structural Metals	0.08879	3,402	6,355	436,994
3353	Electrical Equipment	0.08174	1,107	1,977	293,203
3331	Agriculture, Construction, & Mining Machinery	0.07432	1,407	2,201	209,643
3391	Medical Equipment & Supplies	0.07185	1,242	2,395	165,180
3362	Motor Vehicle Body & Trailer	0.06701	808	1,622	76,925
3256	Soap, Cleaning Compound, & Toilet Preparation	0.05454	957	2,136	442,283
3122	Tobacco	0.04605	593	1,095	
3361	Motor Vehicle	0.03654	11,384	22,724	

Figure 7: Kentucky Gross Domestic Product by Economic Sector, 2009 [4]

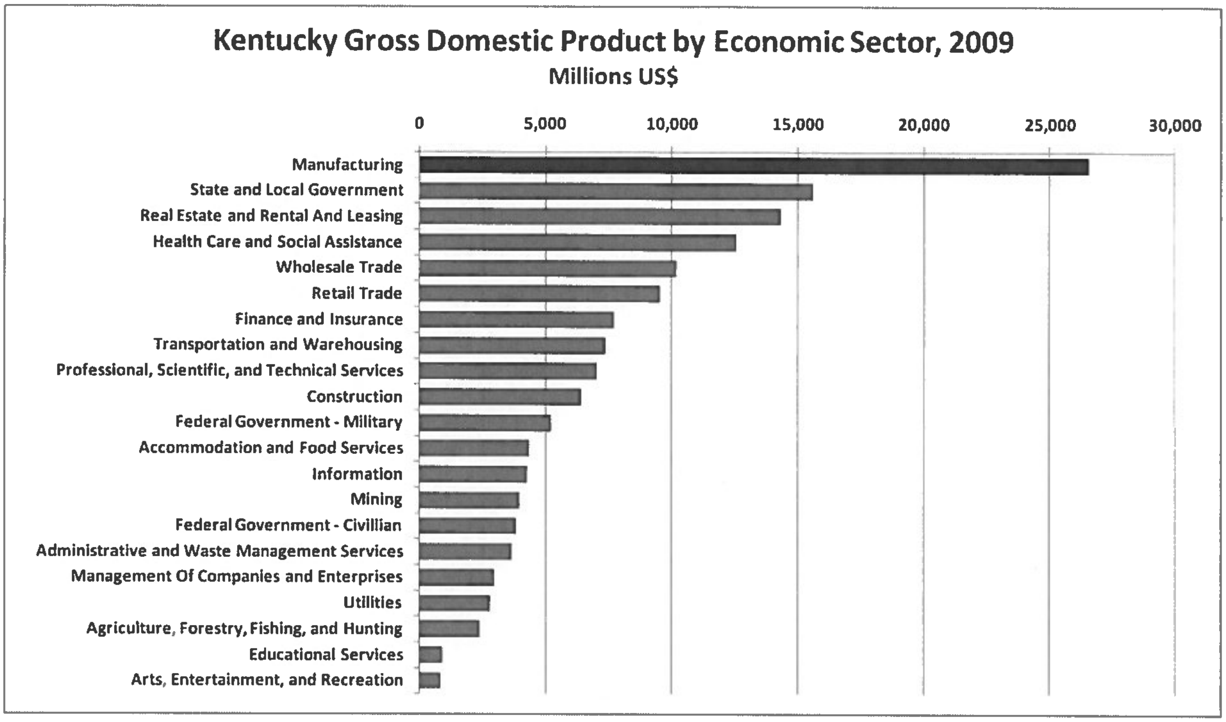
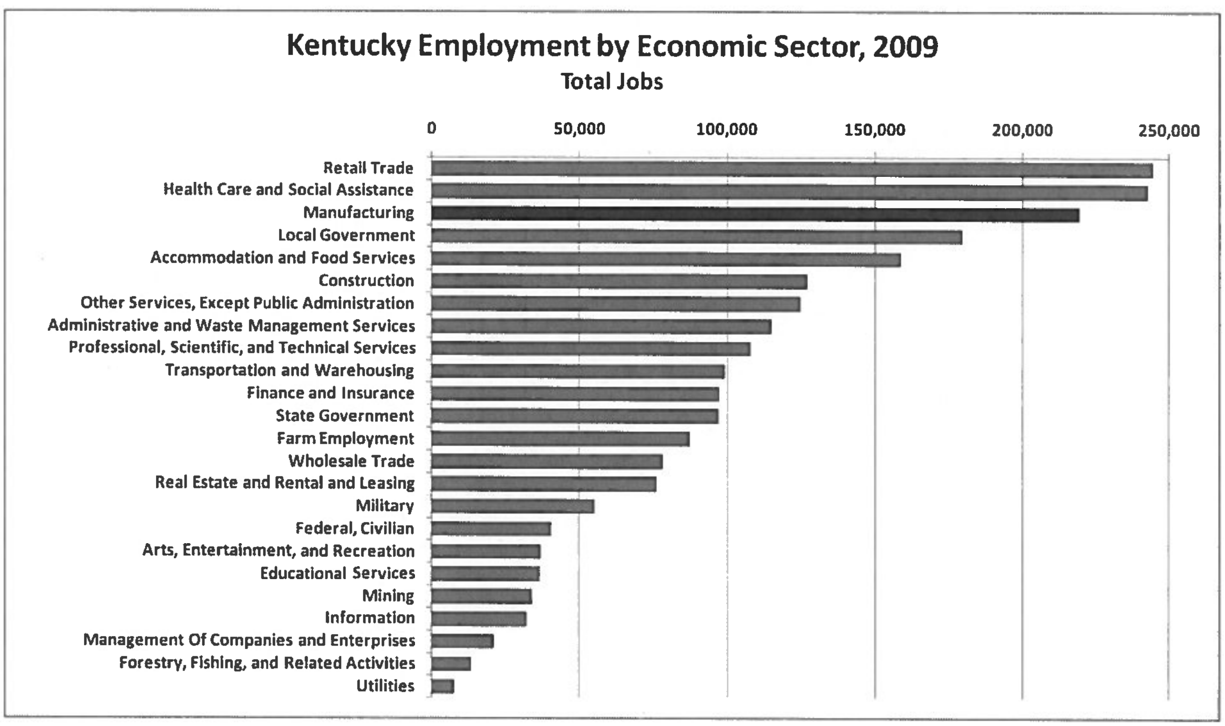


Figure 8: Kentucky Employment by Economic Sector, 2009



Kentucky's electricity-intensive manufacturing economy is threatened by increasing electricity prices. While the price of electricity is only one of several factors influencing industrial location decisions, Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive economy in the United States. In the twenty-first century, the bulwark of the Kentucky economy is clearly manufactured goods—the Commonwealth's single largest source of economic activity. Even mid-recession, as illustrated in Figures 6 and 7 on page 5, manufacturing in Kentucky accounted for more than $26.6 billion in 2009, or 17% of State GDP, and directly employed 213,330 Kentuckians—2.5 times more than were employed as farmers and 11 times more than were employed as coal miners. In addition to being Kentucky's largest source of revenue and a leading source of employment, manufacturing is *sui generis*, fulfilling a unique economic function in that most goods are exported, bringing revenue to the Commonwealth from other economies. This is in contrast to the other top employment opportunities in Kentucky: retail services, health care, local government, food service, and construction, which principally depend upon local sources of revenue. Employment opportunities in manufacturing pay more than the two larger employment sectors, retail and hospitality. Large manufacturers, such as General Electric, Toyota, and Ford Motor in Kentucky, also have a more significant multiplier effect on a regional economy because they encourage suppliers to collocate with manufacturing facilities.[5]And this may well be the greatest significance of coal for the Commonwealth: not the number of persons employed in coal mining operations, nor the direct revenue generated from coal exports, *but rather the sheer size of the manufacturing industry that has located in Kentucky because of low energy costs.*

A variety of econometric studies[6,7] have been conducted to estimate the relationship between electricity prices and employment, also finding that increased electricity prices are associated with reductions in employment. However, none of these studies have taken into account the regional disparities in both the forecasted electricity price increases as well as distribution of electricity-intensive manufacturing as a percentage of total employment or state gross domestic product (GDP). Furthermore, none of these existing studies have specifically analyzed the impact of increasing prices on the most relevant employment sectors in the Commonwealth of Kentucky: manufacturing, retail, hospitality, healthcare and government.

A 2011 report prepared for the Kentucky state government found that increases in the price of electricity are associated with decreases in overall levels of employment. Specifically, the authors posit that a onetime increase of 25% in the price of electricity would reduce the long-run growth rate in total employment from an average of 3.0% to 2.49% per annum.[8] This current study builds upon the their work by using sector-specific employment as the dependent variable rather than total employment in all sectors to identify particular vulnerabilities within the Kentucky economy.

Beyond absolute price, the mere presence of price volatility may make it difficult for electricity-intensive manufacturing businesses to plan ahead and may also discourage capital investment in these engines of economic growth. Electricity price volatility could be included as an independent variable in future studies. For example, one could surmise that during a period of electricity price increases, companies would leave or not expand their existing operations, and this would not necessarily be recovered during periods of declining electricity prices.

Business Response Options to Increasing Electricity Prices

Faced with increasing electricity prices, energy-intensive businesses have the following response options.

1. Pass the price increase directly to consumers, in non-competitive markets.
2. Ignore the price increase and accept a reduction in profit margins.
3. Implement energy efficiency measures to lower total electricity consumption.
4. Substitute electricity with alternative energy sources, where available and competitively priced.
5. Seek government incentives or intervention.
6. Implement efficiency in other areas, including labor costs.
7. Relocate to an area where costs of production will be lower.
8. Close.

Option 1, passing the price increases directly to product end users, will only be a viable option if that industry has a captive or non-competitive market. If market competition is tight or if there are already lower-cost alternatives available to consumers, manufacturers may have limited room to increase prices. Electricity-intensive industries will not likely be able to choose option 2, since electricity expenditures are such a significant portion of their costs of doing business. In such cases, businesses have probably also already implemented energy efficiency measures, option 3, to increase profit margins. However, as much as possible, more efficient use of electricity is preferable under most conditions.

The use of energy substitutes, option 4, for energy-intensive industries in Kentucky may mean substituting direct natural gas combustion for electricity. However, natural gas price volatility, supply, and pipeline access may be prohibiting factors to large scale natural gas substitution.

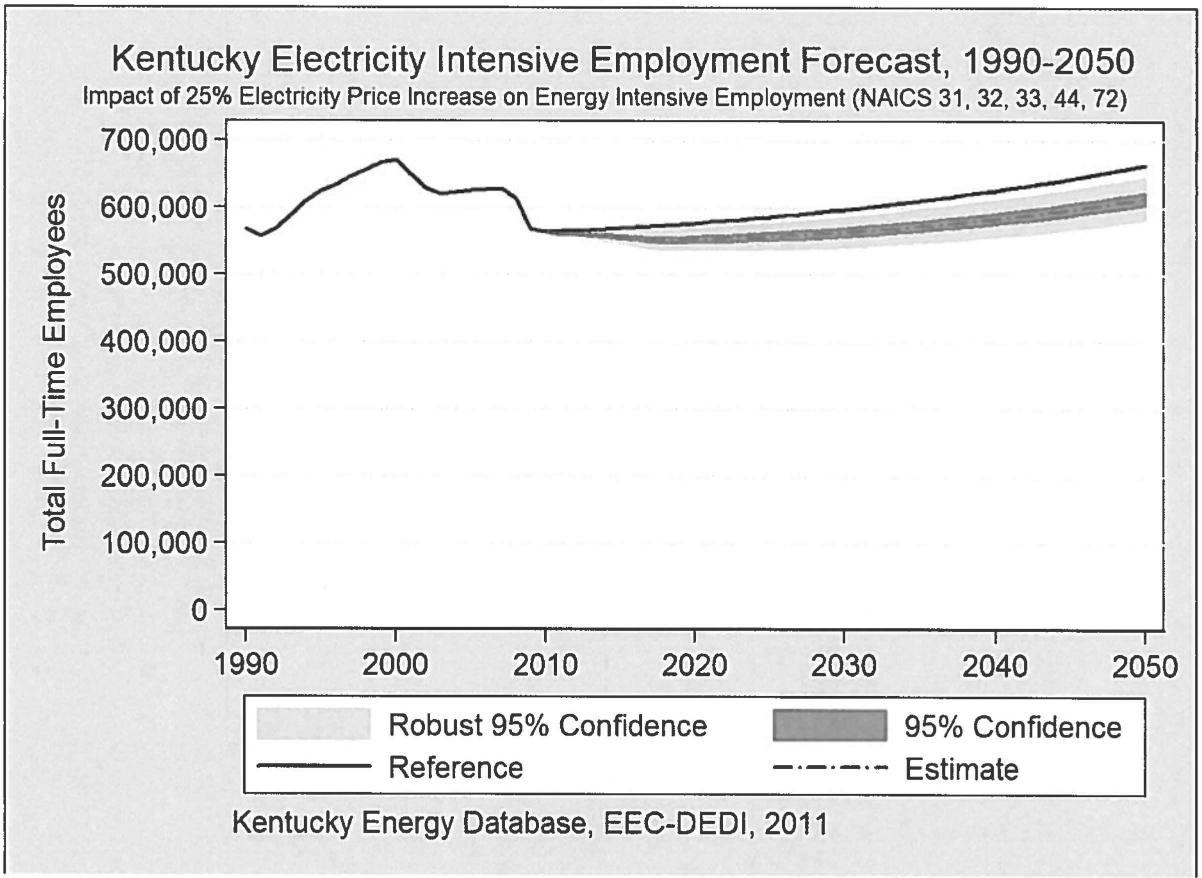
Businesses may also turn to government to either subsidize increasing electricity costs or offset them through taxpayer or ratepayer-funded incentives, option 5. Indeed, many other state governments already offer such incentives to electricity-intensive industries; however, in practice, the long-term affordability of such subsidies must be part of the government's evaluation criterion.

Whenever a business chooses options 6, 7, or 8, there should be a negative impact on total employment. Options 7 and 8 could be measured in total number of employees, whereas option 6 would be better measured using total labor hours or wage data.

Findings

This study builds upon the notion that low energy costs are a catalyst for commercial growth by quantifying the precise vulnerability of the largest economic sectors of the Commonwealth, in terms of total employment, to future electricity price increases. Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, discussed in greater detail in the Statistical Appendix on pages 13 to 19, this study modeled the responsiveness of employment across the United States to changes in the price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing, retail services, hospitality, healthcare, and government. *Elasticities* were developed for each of these economic sectors to calculate changes in employment, given a specific change in the price of electricity, and can be generally applied to the 48 contiguous United States.

Figure 9: Kentucky Electricity Intensive Employment Forecast, 1990-2050



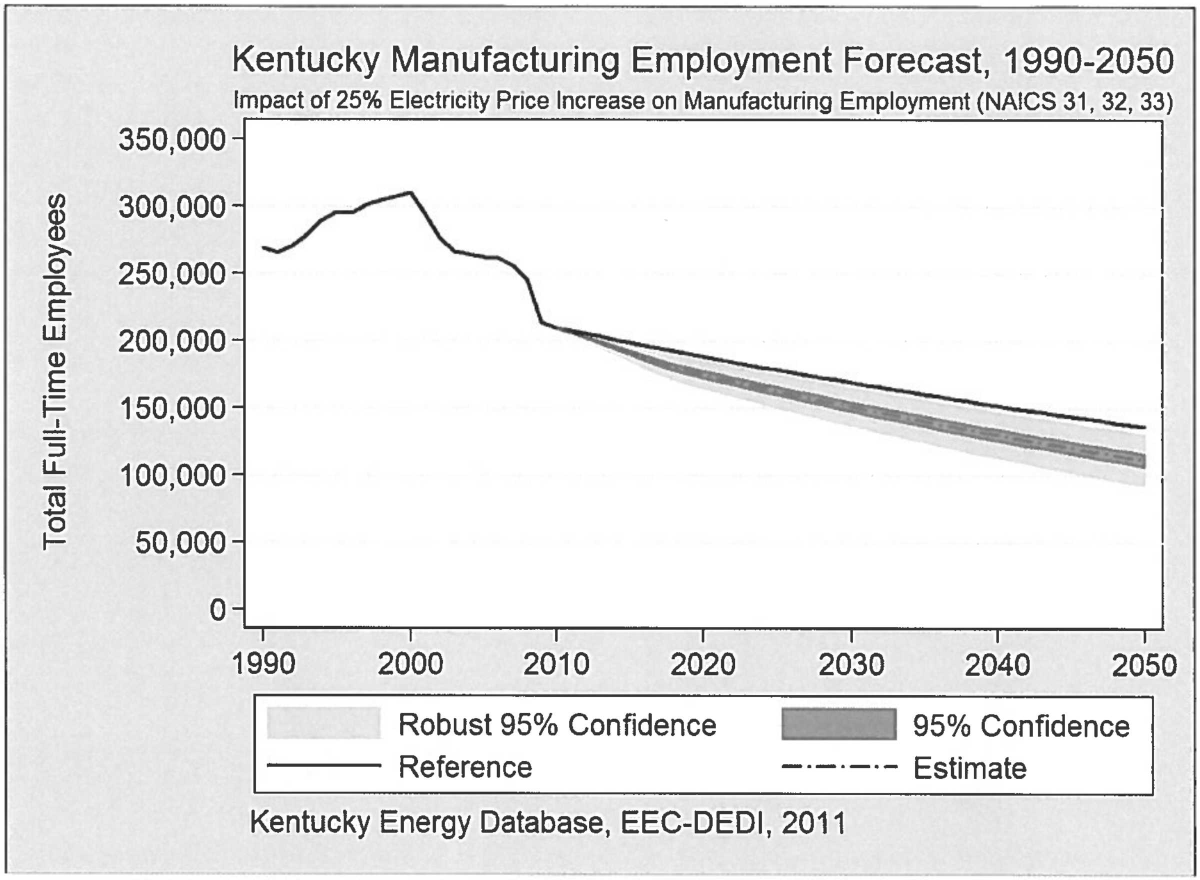
Given the potential cumulative increase of 25% in real electricity prices between 2011 and 2025, this multiple regression model estimates that Kentucky will likely lose, or fail to create, 30,000 full-time jobs long-term. Manufacturing establishments were the most vulnerable to electricity price increases and can be expected to permanently shed 17,500 full-time jobs. Evidence suggests that, once lost, similar manufacturing employment opportunities will never return. The relative extent of this finding is intuitive given that there are 12,685 jobs in the most-electricity intensive manufacturing sectors alone.

Retail stores, restaurants, and hotels were less than half as responsive as the manufacturing sector to increasing electricity prices, and combined, can be expected to fail to create 12,500 full-time jobs. However, in the fourth and fifth largest employment sectors, healthcare and government, no statistically significant relationship between electricity prices and total employment could be identified.

The employment forecast illustrated in Figure 9 above is an aggregation of each of the sector-specific forecasts for the energy-intensive sectors, manufacturing, retail, and hospitality (NAICS 31, 32, 33, 44, & 72). The estimated electricity-related job losses were subtracted from a reference forecast for each sector that simply extrapolated the 20-year average annual growth rate (AGR). The 95% confidence intervals, both with and without robust standard errors, are displayed in gray surrounding the single-point estimations. The delta between the estimate and reference case is the isolated effect of electricity price increases on employment.

Impact on Manufacturing Employment

Figure 10: Kentucky Manufacturing Employment Forecast, 1990-2050

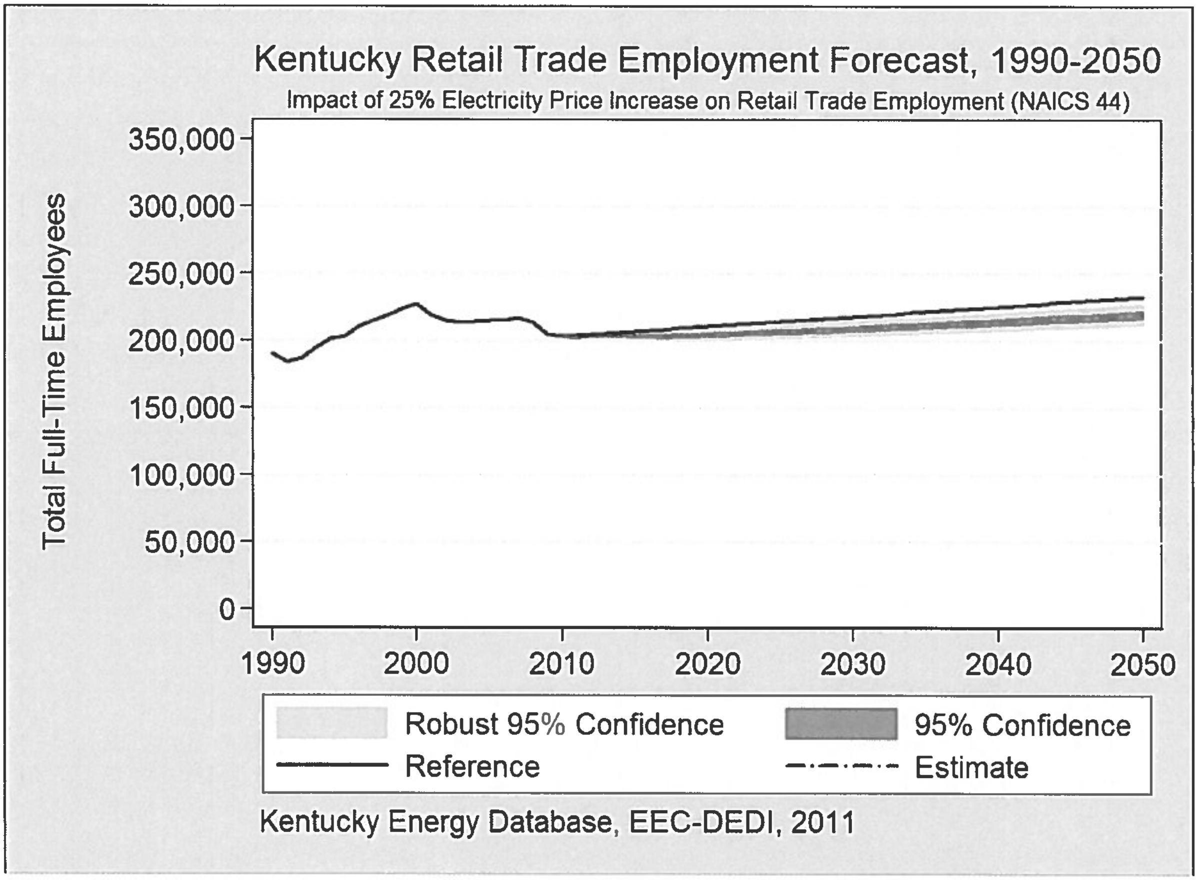


Of the sectors analyzed, manufacturing, Kentucky's largest economic sector, was the most-responsive sector to changes in electricity prices. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 3.37% in absolute manufacturing employment, and with 95% confidence, between -2.77% and -3.97%. This finding was statistically significant below the 0.001 level. When using robust standard errors, however, the 95% confidence interval widened to between -0.83% and -5.92% and the significance level dropped to 0.01. Overall economic activity and time were also significant factors in predicting employment in the manufacturing sector; however, educational attainment as well as the total population levels were not. Time had a statistically significant negative coefficient, reflecting the general trend of contraction of manufacturing both in Kentucky and nationally. Given a 25% increase in real electricity prices by 2025, manufacturing establishments in Kentucky would be expected to permanently shed an additional 17,660 full-time jobs long-run as a direct result of price increases, and with 95% confidence using robust standard errors between 5,764 and 31,022 full-time jobs, *ceteris paribus*.

The manufacturing employment forecast, illustrated in Figure 10 above, was developed by applying the elasticities for the manufacturing sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of -1.16%, and then subtracting predicted historical electricity-related losses, for a net reference AGR of -1.07%.

Impact on Retail Trade Employment

Figure 11: Kentucky Retail Trade Employment Forecast, 1990-2050

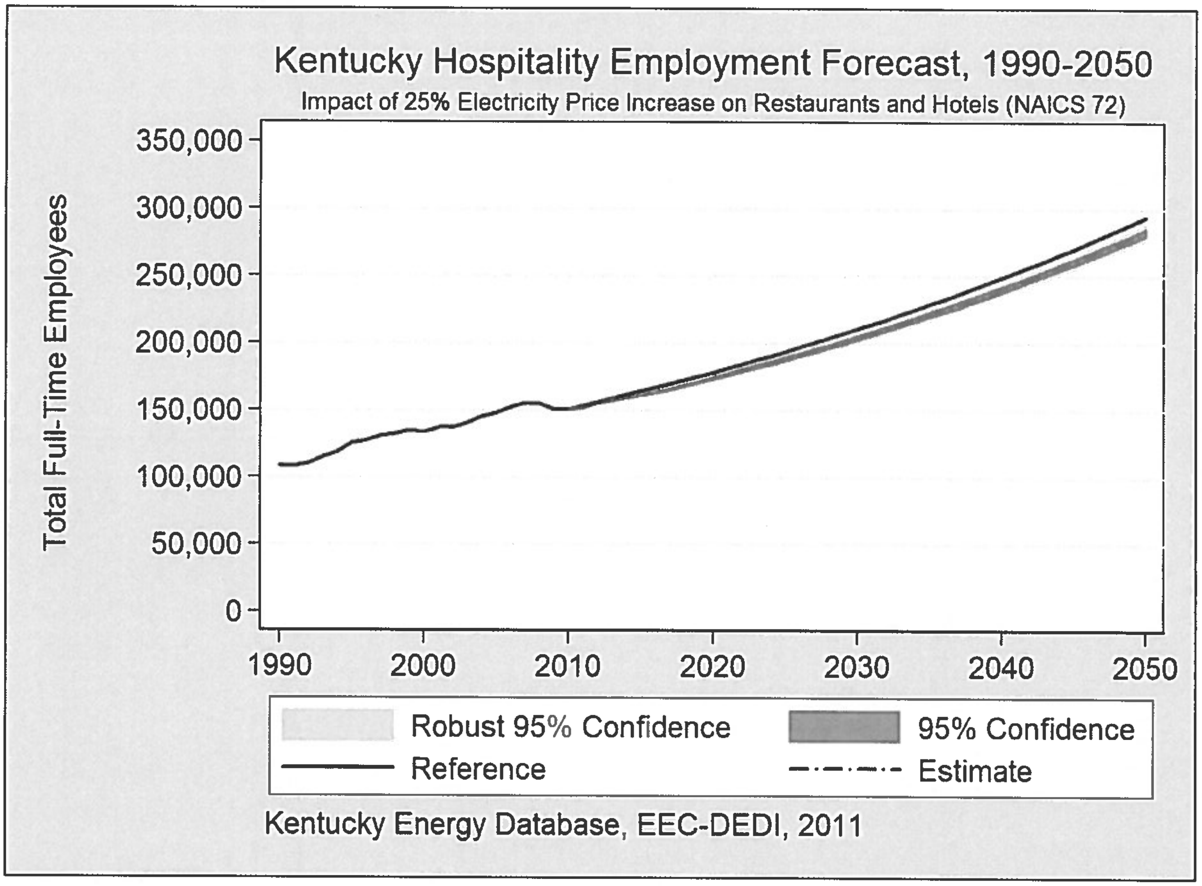


Retail trade, Kentucky's largest employment sector in terms of total employment, was less than half as responsive as the manufacturing sector to increasing electricity prices. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 1.57% in total employment, and with 95% confidence between -1.30% and -1.84%. When using robust standard errors, however, the 95% confidence interval widened between -0.77% and -2.39%. These findings were statistically significant below the 0.001 level. Education was not a significant factor in determining retail employment; whereas economic activity and total population levels were. Given a 25% increase in real electricity prices by 2025, retail establishments in Kentucky would be expected to fail to create 7,225 full-time jobs long-run, and with 95% confidence using robust standard errors, between 3,916 and 12,160 full-time jobs, *ceteris paribus*.

The retail employment forecast, illustrated in Figure 11 above, was developed by applying the elasticities for the retail sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of 0.3584%, and then subtracting predicted historical electricity-related losses, for a net reference AGR of 0.3393%.

Impact on Hospitality Employment

Figure 12: Kentucky Hospitality Employment Forecast, 1990-2050



Employment in hospitality industries such as restaurants and hotels demonstrated a similar, but weaker, responsiveness as retail employment. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 1.42% in total employment, and with 95% confidence between -1.12% and -1.71%. When using robust standard errors, however, the 95% confidence interval widened between -0.78% and -2.06%. This finding was statistically significant below the 0.001 level. Education and total population do not appear to be significant factors in determining hospitality sector employment; whereas economic activity and time were both significant. Given a 25% increase in real electricity prices by 2025, restaurants and hotels in Kentucky would be expected to shed 5,352 full-time jobs long-run, and with 95% confidence using robust standard errors, between 2,940 and 7,765 full-time jobs, *ceteris paribus*.

The retail employment forecast, illustrated in Figure 12 above, was developed by applying the elasticities for the retail sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of 1.6857%.

Impact on Healthcare Employment

Employment in the healthcare industry was much less sensitive to increases in electricity prices, and responsiveness was not statistically significant when using robust standard errors. Specifically, a 10% increase in the price of electricity appears to be associated with a 0.43% reduction in overall healthcare employment. However, with 95% confidence and robust standard errors, these effects are not necessarily distinguishable from zero. Healthcare employment was better predicted by educational attainment of the population, overall economic activity, total population levels, and time. Given that the independent variable of interest, real electricity prices, was not significant when using robust standard errors, no forecast for this sector was developed.

Impact on Government Employment

In government employment, no relationship between electricity prices and total employment could be identified, whereas educational attainment of the population, overall economic activity, and total population levels appeared to have statistically significant effects. Given that the independent variable of interest, real electricity prices, was not significant in any model, no forecast for this sector was developed.

Conclusion

This study demonstrated that electricity price increases alone may force businesses to seek ways to reduce costs or close, causing substantial job losses in Kentucky's electricity-intensive manufacturing sector, and slowing overall long-term job creation in other sectors. The timing of this transition could exacerbate high unemployment and slow economic growth in the near-term. The Commonwealth's vulnerability to these dynamics could also be worsened if leadership is unaware of them and inadequately prepared for the transition. Kentucky's neighboring states of Indiana, Ohio, and West Virginia exhibit similar vulnerabilities due to the potential for increasing electricity costs and the relative size of their manufacturing sectors.

While total employment in the Commonwealth is expected to continue to rise in other sectors, the Commonwealth should maintain focus on education and workforce development in emerging industries that are less reliant on energy-intensive manufacturing processes as well as consider strategies to mitigate vulnerability to price increases and risk exposure.

Data Analyzed

Total employment in Kentucky's top five economic sectors, in terms of number of employees as illustrated in Figure 8 on page 5, served as the dependent variables of interest in this study. Total employment by industry was collected from the Bureau of Economic Analysis (BEA) for all 51 entities and all years from 1990 to 2010. [9] Data was collected for each state as well as the District of Columbia, in each year, and for each industry, organized by North American Industry Classification System (NAICS) codes.

The primary explanatory variable of interest in this study was the natural logarithm of total real electricity price in each state and year expressed in 2010 US$ per kWh. Electricity prices are defined here as the quotient of the total revenue received by electric utilities in state i and in year t divided by the total kilowatt-hours of electricity sold in that state and year. Electricity *prices* differ from electricity *rates*, which are only a subset of the total cost and often do not include taxes, environmental surcharges, and fuel costs that vary substantially across time and geography. Thus, electricity prices more accurately reflect the cost for one kilowatt-hour of electricity paid by consumers in a given state and year. This variable was assembled using a variety of datasets from the Energy Information Administration (EIA), including data from the State Energy Data System (SEDS) for years 1990 to 2009 for all states,[10] and where certified data was not yet available using Form EIA-861[11] and Form EIA-826 for the year 2010.[12] The correlation between historical electricity prices derived from Form EIA-861 and EIA-826 to the corresponding certified variables was 0.999; thus, there is almost no difference between the historical data and the 2010 update other than it has not yet been certified and included in SEDS.

The following control variables were used: educational attainment, defined as the percentage of the adult population (age 25 years and older) with a bachelor's degree (or higher), collected from the United States Census American Community Survey; population, also collected from the United States Census; state Gross Domestic Product (GDP), collected from the BEA; and year. The following control variables were also tested but ultimately excluded because their effects were not statistically significant: labor force unionization, Standard & Poor's 500 Index, and per capita personal income.

There were a total of 51 states included (N=51), the 50 United States as well as the District of Columbia. However, the model's performance would have been improved by ~5% if the District of Columbia had been excluded. All currency variables, namely the price of electricity and State Gross Domestic Product, were adjusted for inflation to 2010 US$ using the Bureau of Labor Statistics (BLS) Consumer Price Index (CPI), which is intended to account for the generally rising cost of goods during this time period.

Analytical Method

Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, this study modeled the responsiveness of employment across the United States to changes in the real price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing (NAICS 31, 32, & 33), retail services (NAICS 44), hospitality (NAICS 72), healthcare (NAICS 62), and government (NAICS 92). Elasticities were developed for each sector to calculate changes in employment given a specific change in the electricity prices and can be generally applied to any state and year.

To develop these elasticity coefficients, data were organized into a multidimensional panel, i.e. both time series and cross sectional, enabling simultaneous modeling of the relationships of multiple statistics across both space and time (N x t). Since each observation is non-random, and not independent, for example electricity prices in state i and year t are not independent of prices in state i in year t-1, a fixed effects model was used, which builds upon Ordinary Least Squares (OLS) regression by isolating the time-independent constant difference between states that is correlated with the explanatory variables. Two multiple regression of panel data models with fixed effects, both with and without robust standard errors, were constructed for each of the top five employment sectors in Kentucky, for a total of 10 separate multiple regression models.

The multiple regression of panel data model with fixed effects can be generally given by,

$$Y_{it} = \beta_0 + \sum_{j=1}^{k-1} \beta_j X_{jit} + \alpha_i + \varepsilon_{it}$$

Where i and t index states and years, such that y_{it} is the dependent variable of interest, employment by industry, in state i in year t, β_0 is the constant y intercept across all states, X is a k by 1 vector of explanatory variables, $\beta_j X_{jit}$ is the product of the observation for each independent variable j through k for state i in year t and the coefficient of X, k is the total number of included independent variables, α_i is the time-invariant fixed effect for state i, and ε_{it} are the residuals, and where $\varepsilon_{it} \sim N(0, \sigma^2)$, or are approximately normally distributed with a mean of zero.

Multiple regression of panel data using fixed effects facilitated controlling for the numerous factors inherently affecting sector-specific employment as well as electricity prices from state to state that have not been accounted for in the independent variables included in this study to isolate the primary national effect of the variable of interest, real electricity prices, on each of the dependent variables, employment by industry. Since this study aims to isolate the unique effect of electricity prices on employment, the model was rerun five times to derive the coefficient for each of the industries of interest by NAICS code.

A fixed effects model specifically assumes the existence of unobserved time-invariant heterogeneity, often referred to as unobserved variable bias, which in addition to the included independent variables, is affecting the dependent variable. The fixed effects model will attempt to control for these missing or unobserved between unit (interstate) factors, the fixed effects, to isolate the specific net effect of the independent variables of interest on all units (nationally). The fixed effects model also assumes that these between-unit effects are both time invariant and correlated with the independent variables. A fixed effect model is also functionally, although not computationally, equivalent to assigning an independent indicator variable, or dummy variable (0 or 1), for each state, to isolate the specific effect for each state without having to create the 51 additional independent variables.

The Hausman test, which is often used in econometrics to determine the appropriateness of a fixed effect versus a random effect model, is not required here because this study is modeling the entire population of states (*N*), thus necessitating a fixed effects model and obviating a random effects model. A random effect model is only suitable to model the sample (*n*) of the population that has been selected at random.

Table 2 on page 16 shows the multiple regression models with fixed effects estimated for each of the top five employment sectors. These five models were subsequently rerun using robust standard errors in order to prevent biased estimation that could be caused by the presence of outliers in manufacturing employment, such as the District of Columbia, as well as the presence of the residual heteroscedasticity as identified by the Breusch–Pagan post estimation test. Robust standard errors were calculated using the Huber-White sandwich estimator.[13] The resulting five multiple regression models with fixed effects and robust standard errors are shown in Table 3 on page 17. However, using robust standard errors had little impact on the relationships of interest; the effect of electricity prices on manufacturing employment remained significant with a p-value of 0.010.

Prior to analysis, all variables were converted to their natural logarithms such that the estimated coefficients for each may be simply interpreted as elasticities, which measure the percentage change in the dependent variable given a percentage change in one of the independent variables. For electricity prices specifically, the independent variable of interest in this study, the coefficients summarized in the first row of Tables 2 and 3 are the estimated electricity price elasticity of employment for each specific economic sector, which is the expected percentage change in employment given a percentage change in the price of electricity, *ceteris paribus*, or holding all other included independent variables constant.

Since these elasticities were derived through regression of national historical data, they may be generally applied to any state and year and to the United States as a whole for each respective economic sector. The only difficult math in this process is in the development of the elasticity coefficients themselves. Therefore, assuming a reliable electricity price forecast has already been developed, the long-term change in employment in a given sector for other states and for different changes in the price of electricity can be calculated by simply multiplying the number of employees in that sector currently by the forecasted percentage change in real electricity prices, i.e. inflation adjusted, multiplied by the specified elasticity coefficient for that sector. For example, given that there were 209,609 employees in all manufacturing sectors in Kentucky in 2010, and assuming real electricity prices increased by 25%, and given that the electricity price elasticity of manufacturing employment calculated here is 0.337, then the estimated long-term job losses resulting from the increase in electricity prices would 17,660, as illustrated below.

	209,609	*Number of Employees in NAICS Sectors 31, 32, & 33*
x	0.25	*% Change in Electricity Price*
x	0.337	*Sector-Specific Elasticity Coefficient*
=	17,660	*Resulting Long-Term Job Losses*

The employment forecasts illustrated in Figures 12 through 21 on the following pages were produced by integrating the elasticities developed in this study into the Kentucky Electricity Portfolio Model. This facilitated creating dynamic employment forecasts for different electricity price scenarios that were responsive to the forecasted change in real prices in each future year. No lags have been assumed.

Table 2: Model of Electricity Prices & Employment by Economic Sector

Logged Variables	Manufacturing Employment		Retail Employment		Food & Accommodation Employment		Healthcare Employment		Government Employment	
Price of Electricity (Real 2010 US$)	-0.337	***	-0.158	***	-0.142	***	-0.0426	**	0.00084	
	(-0.0307)		(-0.0136)		(-0.0152)		(-0.0158)		(-0.0101)	
Educational Attainment	0.0249		-0.108		-0.0679		-0.536	***	-0.14	**
	(-0.146)		(-0.065)		(-0.0728)		(-0.0758)		(-0.0482)	
State GDP (Real 2010 US$)	0.744	***	0.509	***	0.318	***	0.17	***	0.253	***
	(-0.0514)		(-0.0228)		(-0.0255)		(-0.0265)		(-0.0169)	
Population	0.166	**	0.26	***	0.129	***	0.37	***	0.258	***
	(-0.0532)		(-0.0236)		(-0.0264)		(-0.0275)		(-0.0175)	
Year	-76.05	***	-11.31	***	21.11	***	55.21	***	3.801	*
	(-5.536)		(-2.457)		(-2.752)		(-2.861)		(-1.819)	
Constant	579.4	**	88.85	***	-153.9	***	-413.5	***	-22.72	
	(-41.38)		(-18.36)		(-20.57)		(-21.39)		(-13.6)	
R-Squared	0.7776		0.956		0.9219		0.8885		0.9344	
Observations (*N x t*)	1069		1071		1069		1071		1071	
Number of States (*N*)	51		51		51		51		51	

Standard Errors in Parentheses
Asterisk Denotes Statistical Significance at the Following Levels: * $p<0.05$, ** $p<0.01$, *** $p<0.001$
All Variables Transformed into their Natural Logarithms

**Table 3: Model of Electricity Prices & Employment by Economic Sector
With Robust Standard Errors**

Logged Variables	Manufacturing Employment	Retail Employment	Food & Accommodation Employment	Healthcare Employment	Government Employment
Price of Electricity (Real 2010 US$)	-0.337 * (-0.127)	-0.158 *** (-0.0404)	-0.142 *** (-0.032)	-0.0426 (-0.0377)	0.00084 (-0.0285)
Educational Attainment	0.0249 (-0.598)	-0.108 (-0.23)	-0.0679 (-0.216)	-0.536 (-0.345)	-0.14 (-0.155)
State GDP (Real 2010 US$)	0.744 *** (-0.141)	0.509 *** (-0.115)	0.318 *** (-0.0789)	0.17 (-0.0939)	0.253 *** (-0.0719)
Population	0.166 (-0.19)	0.26 (-0.134)	0.129 (-0.0835)	0.37 * (-0.155)	0.258 * (-0.124)
Year	-76.05 ** (-22.38)	-11.31 (-10.79)	21.11 * (-9.212)	55.21 *** (-14.23)	3.801 (-5.988)
Constant	579.4 ** (-166.9)	88.85 (-80.3)	-153.9 * (-68.98)	-413.5 *** (-106.3)	-22.72 (-44.06)
R-Squared	0.7776	0.956	0.9219	0.8885	0.9344
Observations (*N x t*)	1069	1071	1069	1071	1071
Number of States (*N*)	51	51	51	51	51

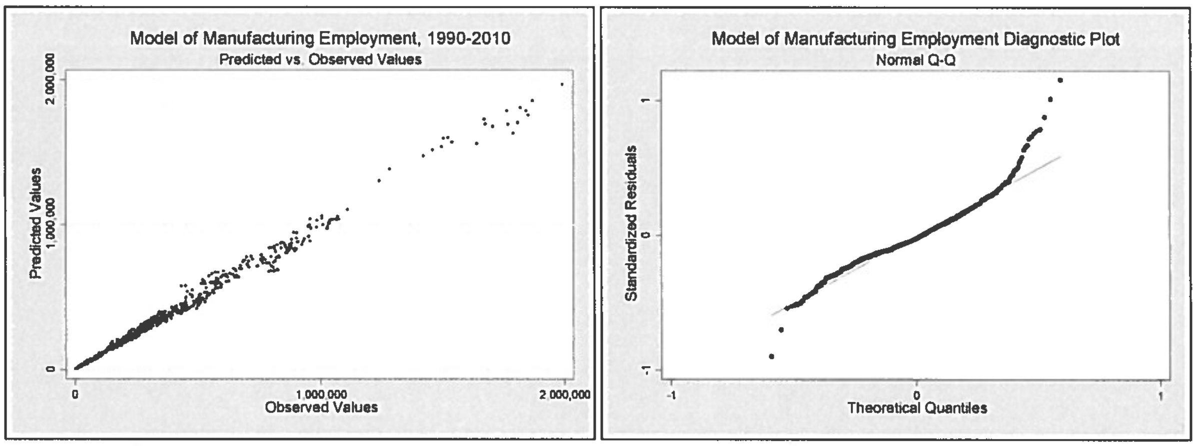
Robust Standard Errors in Parentheses
Asterisk Denotes Statistical Significance at the Following Levels: * $p<0.05$, ** $p<0.01$, *** $p<0.001$
All Variables Transformed into their Natural Logarithms.

Model Diagnostic Plots

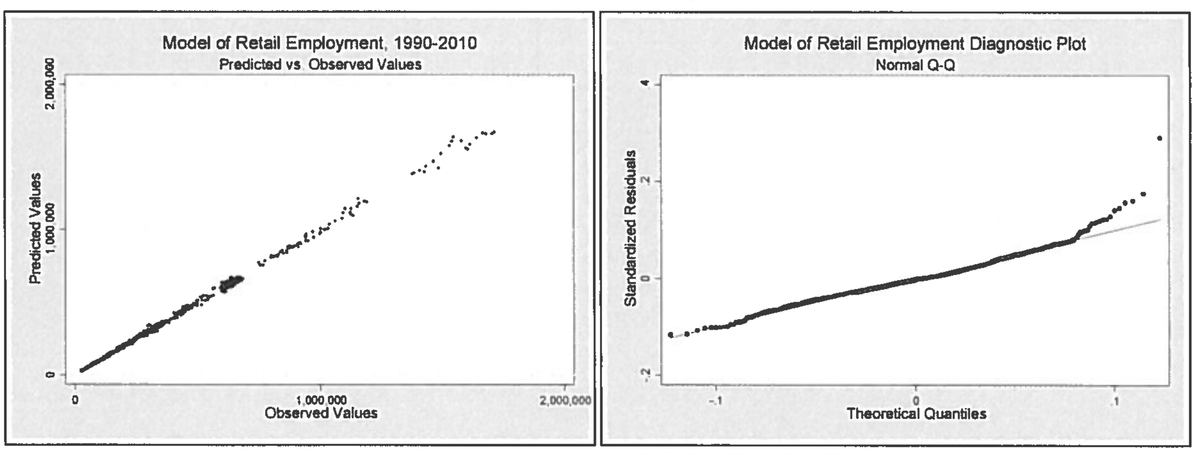
For each economic sector below, the diagnostic plot on the left shows the model's predicted employment versus employment that was actually observed in that state and year, such that all deviations from a perfect line illustrate model error (ε_{it}). The predicted values in all graphics include not only the homogenous, i.e. national, model components, including the constant (β_0) and the product of each variable j to k and the coefficient of each ($\beta_j X_{jit}$), but also the time-invariant interstate fixed effect (α_i) in the response variable, employment, estimated for each state.

The Q-Q plot on the right illustrates the standardized residuals of the model for each economic sector versus their normal theoretical quantiles and are intended to demonstrate that the residuals are approximately normally distributed with a mean of zero, such that $\varepsilon_{it} \sim N(0, \sigma^2)$.

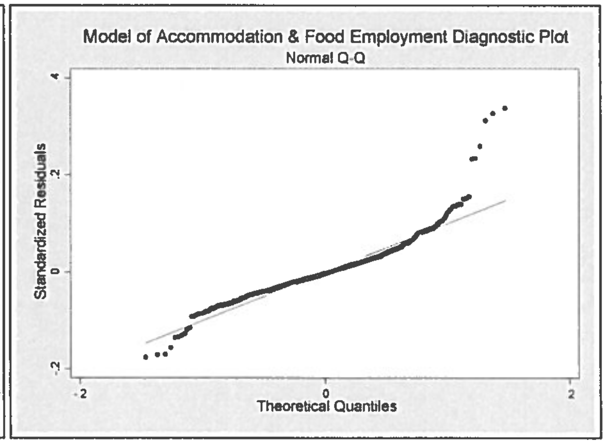
Figures 13 & 14: Model of Manufacturing Employment Diagnostic Plots



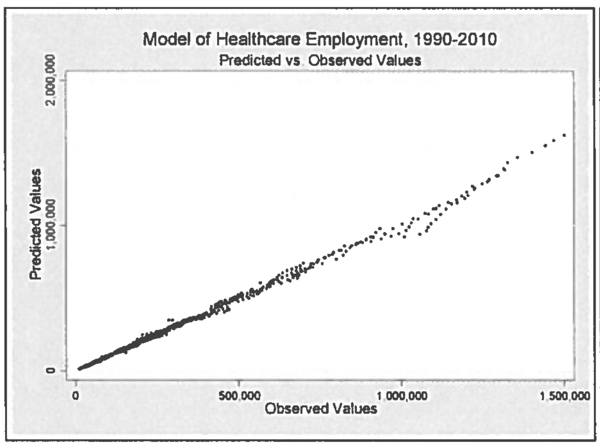
Figures 15 & 16: Model of Retail Employment Diagnostic Plots

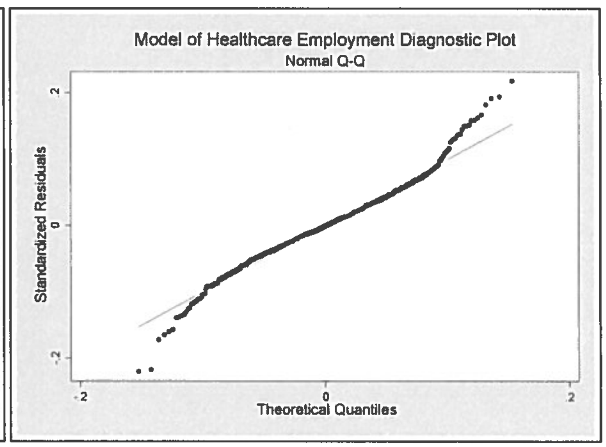


Figures 17 & 18: Model of Food & Accommodation Employment Diagnostic Plots

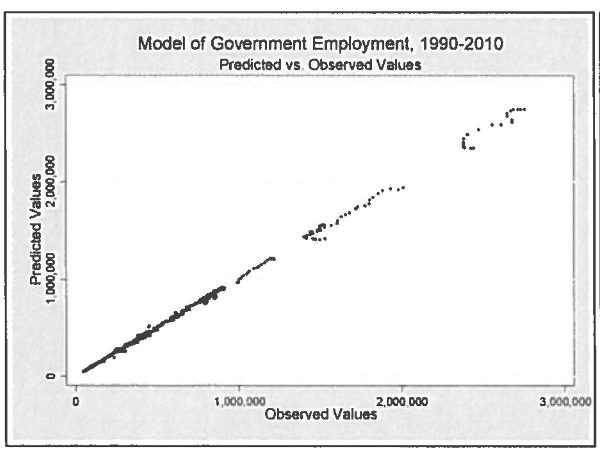


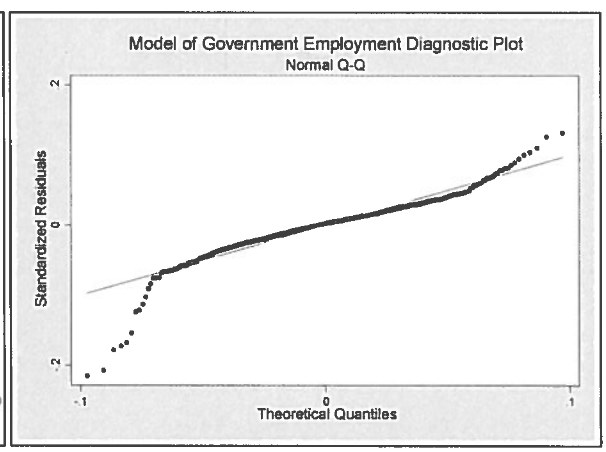
Figures 19 & 20: Healthcare Employment Diagnostic Plots





Figures 21 & 22: Model of Government Employment Diagnostic Plots





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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND ALL OTHER REQUIRED APPROVALS AND RELIEF	))))))))))	**Case No. 2017-00179**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2017

KIUC Proposed Revenue Allocation
Illustration of an Assumed Commission Reduction to the KPCo Requested $60.4 Million Increase

Assumed Adjustment:	$	(20,000,000)
Assumed Authorized Increase:	$	40,397,437

Current Class	Current Revenue	KPCo Proposed Increase		STEP 1 Eliminate IGS Subsidy	STEP 2 Adjusted Increase	STEP 3 Remaining Adjustment	Adjusted Total Increase (Current Revenues)*		% Increase Non-Fuel Revenues*
		$	%				$	%	%
(1)	(2)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
RS	215,744,788	34,503,794	15.99		34,503,794	(8,984,039)	$25,519,755	11.83	16.27
SGS	18,576,461	1,692,810	9.11		1,692,810	(440,771)	$ 1,252,039	6.74	8.48
MGS	53,330,702	5,403,351	10.13		5,403,351	(1,406,915)	$ 3,996,436	7.49	9.98
LGS	51,375,193	4,762,492	9.27		4,762,492	(1,240,050)	$ 3,522,442	6.86	9.69
IGS	138,769,640	11,852,794	8.54	(5,778,385)	6,074,410	(1,581,644)	$ 4,492,765	3.24	6.44
PS	11,504,476	1,287,311	11.19		1,287,311	(335,188)	$ 952,123	8.28	11.49
MW	194,343	15,071	7.75		15,071	(3,924)	$ 11,147	5.74	8.14
OL	8,231,794	780,081	9.48		780,081	(203,116)	$ 576,965	7.01	8.25
SL	1,407,108	99,733	7.09		99,733	(25,968)	$ 73,765	5.24	6.31
Total	499,134,505	60,397,437	12.10	(5,778,385)	54,619,053	(14,221,616)	$40,397,437	8.09	12.08

KIUC Proposed Revenue Allocation
Illustration of an Assumed Commission Reduction to the KPCo Requested $60.4 Million Increase

Assumed Adjustment:	$ (45,000,000)
Assumed Authorized Increase:	$ 15,397,437

Current Class	Current Revenue	KPCo Proposed Increase		STEP 1 Eliminate IGS Subsidy	STEP 2 Adjusted Increase	STEP 3 Remaining Adjustment	Adjusted Total Increase (Current Revenues)*		% Increase Non-Fuel Revenues*
		$	%				$	%	%
(1)	(2)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
RS	215,744,788	34,503,794	15.99		34,503,794	(24,776,968)	$ 9,726,826	4.51	6.20
SGS	18,576,461	1,692,810	9.11		1,692,810	(1,215,597)	$ 477,213	2.57	3.23
MGS	53,330,702	5,403,351	10.13		5,403,351	(3,880,114)	$ 1,523,237	2.86	3.80
LGS	51,375,193	4,762,492	9.27		4,762,492	(3,419,917)	$ 1,342,575	2.61	3.69
IGS	138,769,640	11,852,794	8.54	(5,778,385)	6,074,410	(4,361,997)	$ 1,712,412	1.23	2.45
PS	11,504,476	1,287,311	11.19		1,287,311	(924,410)	$ 362,901	3.15	4.38
MW	194,343	15,071	7.75		15,071	(10,822)	$ 4,249	2.19	3.10
OL	8,231,794	780,081	9.48		780,081	(560,172)	$ 219,909	2.67	3.15
SL	1,407,108	99,733	7.09		99,733	(71,618)	$ 28,115	2.00	2.41
Total	499,134,505	60,397,437	12.10	(5,778,385)	54,619,053	(39,221,616)	$15,397,437	3.08	4.60

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND ALL OTHER REQUIRED APPROVALS AND RELIEF	))))))))))	Case No. 2017-00179

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2017

ROBINSON
&McELWEE
PLLC
attorneys at law

BRIAN E. CALABRESE
ATTORNEY AT LAW

P.O. BOX 1791
CHARLESTON, WV 25326

CHARLESTON OFFICE: (304) 344-5800
DIRECT DIAL: (304) 347-8344
FACSIMILE: (304) 344-9566
E-MAIL: bec@ramlaw.com

November 24, 2015

BY HAND DELIVERY

Ms. Ingrid Ferrell
Executive Secretary
West Virginia Public Service Commission
201 Brooks Street
Charleston, WV 25301

03:29 PM NOV 24 2015 PSC EXEC SEC DIV

Re: Application for approval of demand response and backup and maintenance service tariff provisions
Case No. 15-1734-E-T-PC

Dear Ms. Ferrell:

I submit herewith, on behalf of Appalachian Power Company and Wheeling Power Company (the "Companies"), the original and twelve (12) copies of the **Direct Testimonies of John J. Scalzo and Alex E. Vaughan** for filing in the above-referenced matter.

Very truly yours,

Brian E. Calabrese

Brian E. Calabrese (W.Va. State Bar #12028)
bec@ramlaw.com

Counsel for Appalachian Power Company
and Wheeling Power Company

BEC:tlw
Enclosures

Charleston, WV | Clarksburg, WV | Wheeling, WV | Alliance, OH
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APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
ALEX E. VAUGHAN

COMPANY EXHIBIT AEV-D

**DIRECT TESTIMONY OF
ALEX E. VAUGHAN
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF
WEST VIRGINIA IN CASE NO. 15-1734-E-T-PC**

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Alex E. Vaughan. I am employed by American Electric Power Service Corporation ("AEPSC") as Manager-Regulated Pricing and Analysis. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo").

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS MANAGER-REGULATED PRICING AND ANALYSIS FOR AEPSC.

A. My responsibilities include the oversight of cost of service analyses, rate design, and special contracts for the AEP system operating companies. I am directly responsible for assisting AEP system operating companies APCo and WPCo in their regulatory filings in West Virginia.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of both APCo and WPCo. I shall refer to these entities collectively as the "Companies."

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEP, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the Regional Transmission Organization ("RTO") Settlements Group. I later became the PJM Settlements Lead Analyst and, as such, was responsible for reconciling AEP's settlement of its activities in the PJM Interconnection, L.L.C. ("PJM") market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the Federal Energy Regulatory Commission. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony to this Commission and testified in Case No. 14-1152-E-42T on behalf of the Companies. In addition, I submitted testimony on behalf of APCo before the Virginia State Corporation Commission in Case Nos. PUE-2012-00094, PUE-2013-00111, PUE-2015-00034 and testified in Case Nos. PUE-2013-00009, PUE-2014-00007, and PUE-2014-00026. I have also submitted direct testimony to the Indiana Utility Regulatory Commission in Cause No. 43774-PJM-3 on behalf of Indiana Michigan Power Company and to the

Kentucky Public Service Commission in Case Nos. 2013-00197 and 2014-00396 on behalf of Kentucky Power Company, both of which are AEP operating subsidiaries.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I sponsor the Companies' proposed demand response service ("D.R.S.") riders and explain (i) the two different D.R.S. rider offerings; (ii) their terms and conditions of service; and (iii) how the proposed D.R.S. riders may be applicable to the Companies' customers that are currently served under special contracts with interruptible service provisions.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

(1) Company Exhibit AEV-D1 – Rider D.R.S. – RTO Capacity

(2) Company Exhibit AEV-D2 – Rider D.R.S.

(3) Company Exhibit AEV-D3 – Schedule S.B.S.

(4) Company Exhibit AEV-D4 – Proposed D.R.S. Credit Pricing Calculations

(5) Company Exhibit AEV-D5 – Proposed Schedule S.B.S. Rate Design

RIDER D.R.S.-RTO CAPACITY

Q. PLEASE SUMMARIZE THE COMPANIES' PROPOSED RIDER D.R.S.-RTO CAPACITY.

A. Service under proposed Rider D.R.S.-RTO Capacity is optional and open to all APCo and WPCo customers taking service under rate schedules GS, LCP, or IP and having at a minimum 500 kilowatts ("kW") of interruptible capacity. Customers that qualify for and elect to take service under proposed Rider D.R.S.-

RTO Capacity must meet all qualifications of PJM's Load Management Demand Response program so that their interruptible capacity can be utilized as capacity in the Companies' fixed resource requirement ("FRR") capacity plan. The PJM qualifications for the various D.R.S. product types may vary.

Q. WHAT IS THE INITIAL CONTRACT TERM UNDER RIDER D.R.S.-RTO CAPACITY?

A. The minimum initial commitment under Rider D.R.S.-RTO Capacity is four years. This time period aligns the Companies' demand response resource commitments with PJM's capacity planning process. At any given time, the Companies will have already planned for their capacity requirements three years in advance.

Q. WILL THE COMPANIES RECEIVE PJM CAPACITY VALUE FOR THE DEMAND RESPONSE RESOURCES CONTRACTED FOR UNDER RIDER D.R.S.-RTO CAPACITY?

A. Yes. The Companies can and will register the Rider D.R.S.-RTO Capacity resources with PJM. By doing this, the Companies can utilize Rider D.R.S.-RTO Capacity resources in their FRR plan for meeting their PJM capacity obligations.

Q. PLEASE EXPLAIN THE MULTIPLE CAPACITY PRODUCT OPTIONS WITHIN RIDER D.R.S.-RTO CAPACITY.

A. As can be seen in the rider, for PJM delivery years 2015/2016, 2016/2017, and 2017/2018 (ending May 31, 2018), PJM is offering three different demand response program options. The demand credit pricing is not set by PJM, but, as I discuss below, proposed by the Companies. The three options are the following:

D.R.S. Product Option	Curtailment Availability	Maximum Number of Curtailments	Hours of Day Required to Respond	Maximum Duration of Curtailments	Curtailment Demand Credit $/kW – Month
Limited	Any weekday during June – September of DY	10	12 PM-8 PM	6 Hours	3.52
Extended Summer	Any day during June – October and following May of DY	Unlimited	10 AM-10 PM	10 Hours	4.10
Annual	Any day during DY	Unlimited	June- October and following May of DY (10 AM-10 PM) November-April (6 AM-9 PM)	10 Hours	4.69

Each PJM demand response product offering has different parameters, including a different demand credit ($/kW-Month). Beginning June 1, 2018, PJM will be offering only two different demand response program options. The demand credit pricing is not set by PJM, but, as I discuss below, proposed by the Companies. The two options are the following:

D.R.S. Product Option	Curtailment Availability	Maximum Number of Curtailments	Hours of Day Required to Respond	Maximum Duration of Curtailments	Curtailment Demand Credit $/KW – Month
Base Capacity (2018/19 & 2019/20 DY only)	Any day during June – September of DY	Unlimited	10 AM – 10 PM	10 Hours	4.10
Capacity Performance (Effective 2018/19)	Any day during DY (unless on an approved outage during October-April)	Unlimited	June-October and following May of DY (10 AM-10 PM) November-April (6 AM-9 PM)	-------	4.69

Customers electing to take service under proposed Rider D.R.S.-RTO Capacity must choose the PJM demand response product option in which they want to participate.

Q. WHY IS THE PRICING DIFFERENT FOR THE VARIOUS D.R.S. PRODUCT OPTIONS UNDER RIDER D.R.S.-RTO CAPACITY?

A. The various D.R.S. product options contain different parameters and obligations for those customers that elect to participate in them. Accordingly, the Companies are offering different credits, commensurate with the level of curtailment obligation associated with the different product options.

Q. HOW WAS THE PRICING DETERMINED FOR THE VARIOUS D.R.S. PRODUCT OPTIONS UNDER RIDER D.R.S.-RTO CAPACITY?

A. The Companies utilized PJM's Net CONE as the starting point for determining the pricing points for their proposed Rider D.R.S.-RTO Capacity product options. Net CONE is PJM's proxy for the "Cost of New Entry." It is the estimated capital cost of building a combustion turbine generator in PJM's footprint, less the expected energy and ancillary service revenues that the combustion turbine generator would produce.

Q. WHY DID THE COMPANIES CHOOSE PJM'S NET CONE AS THE STARTING POINT FOR PRICING THE RIDER D.R.S.-RTO CAPACITY PRODUCT OPTIONS?

A. Net CONE is a publicly available proxy for the avoided cost of an incremental capacity addition, assuming that the addition would be that of a combustion turbine plant. Using Net CONE as a starting point for the proposed Rider D.R.S.-

RTO Capacity pricing is appropriate because the demand response resources under this rider would be similar to a combustion turbine in that they both have little energy value and are generally acquired for capacity purposes.

Q. HOW DID THE COMPANIES ARRIVE AT THE PROPOSED PRICING FOR RIDER D.R.S.-RTO CAPACITY?

A. Rather than focusing on one point in time, the final pricing is based on a four-year average of Net CONE adjusted for PJM scaling factors. For each Rider D.R.S.-RTO Capacity product option, a different percentage of this average adjusted Net CONE figure was used to compute the proposed kW-month credits included in Rider D.R.S.-RTO Capacity. The Companies used 30%, 35%, and 40%, respectively, for the limited, summer unlimited, and annual unlimited product options.[1] The escalating prices for these product options are a reflection of their increasing levels of possible curtailment obligations.

Q. WHY IS THE PRICING A PERCENTAGE OF THE AVERAGE ADJUSTED NET CONE VALUES?

A. The Companies are proposing to offer a percentage of the average, adjusted Net CONE values rather than the entire value as the credits for Rider D.R.S.-RTO Capacity resources because of the emergency nature of the product options. Rider D.R.S.-RTO Capacity resources will be called to curtail by PJM (and the Companies) only when emergency and pre-emergency conditions exist. The

[1] Beginning with the 2018/2019 delivery year, the limited, summer unlimited, and annual unlimited product options will be replaced by PJM's base capacity and capacity performance product options. Because of similarities in curtailment obligations, the base capacity product option has the same proposed pricing as the summer limited product option, and the capacity performance has the same proposed pricing as the annual unlimited product option.

amount of possible curtailments under Rider D.R.S.-RTO Capacity is further limited by the various product option parameters. For these reasons, crediting Rider D.R.S.-RTO Capacity resources at the full average, adjusted Net CONE value would not be appropriate. However, since the Rider D.R.S.-RTO Capacity resources will count as PJM capacity in the Companies' FRR plan, the proposed percentages of average, adjusted Net CONE yield reasonable credits.

Q. CAN A CUSTOMER PARTICIPATE IN PJM'S DEMAND RESPONSE MARKETS IF IT IS TAKING SERVICE UNDER THE COMPANIES' RIDER D.R.S.-RTO CAPACITY?

A. Yes, but only as a demand response resource in PJM's regulation service market. The Companies will register the interruptible load of customers that elect to take service under Rider D.R.S.-RTO Capacity as "Load Management DR Full" resources in PJM.

Q. WILL CUSTOMERS TAKING SERVICE UNDER RIDER D.R.S.-RTO CAPACITY RECEIVE AN ENERGY CREDIT FOR CURTAILMENTS UNDER THIS RIDER?

A. No. Any energy payments from PJM that the Companies would receive for curtailments under this rider will be included in the Companies' monthly ENEC calculations as a credit to all customers. This ratemaking treatment is appropriate because all customers would be paying for the Rider D.R.S.-RTO Capacity payments made to interruptible customers through the ENEC, as discussed by Company witness Scalzo.

Q. IS THERE AN INITIAL REVENUE REQUIREMENT ASSOCIATED WITH PROPOSED RIDER D.R.S.-RTO CAPACITY?

A. No. Proposed Rider D.R.S. - RTO Capacity is a new program, so there are no customers participating at this time. However the Companies do have a number of interruptible special contract customers that would qualify for proposed Rider D.R.S. - RTO Capacity. As discussed later in my testimony and in Company witness Scalzo's testimony, the rate credits for those interruptible customers are currently included in base rates.

Q. PLEASE DESCRIBE OTHER BENEFITS OF PROPOSED RIDER D.R.S.-RTO CAPACITY.

A. There is value to the Companies and their customers in having a standard, Commission-approved value for demand response capacity. There are administrative efficiency gains in not having individualized contracts with various customers for demand response capacity. Utilizing a Commission-approved rider rather than confidential special contracts also provides a level of transparency to the customers that are paying for demand response capacity. This tariff filing also provides all interested parties an opportunity to be involved in the determination of the proper value for demand response capacity and whether the Companies should increase their demand response capacity resources beyond their current interruptible customers' capacity.

RIDER D.R.S.

Q. PLEASE SUMMARIZE THE COMPANIES' PROPOSED RIDER D.R.S.

A. Service under proposed Rider D.R.S. is optional and open to all APCo and WPCo customers taking service under rate schedules GS, LCP, or IP and having at a minimum 500 kW of interruptible capacity. Under this rider, the Companies, in their sole discretion, would have the right to call for curtailments of the customer's interruptible capacity at any time. Such interruptions would be designated as discretionary interruptions and would not exceed an aggregate of either 80 or 160 hours of interruption during any Interruption Year, depending on which option a participant chooses. APCo or WPCo would provide customers with at least 60 minutes of notice prior to the commencement of a discretionary interruption. The benefits of such a rider are discussed by Company witness Scalzo.

Q. WHAT CURTAILMENT LIMITATIONS ARE BEING PROPOSED BY THE COMPANIES?

A. The Companies propose that discretionary interruption events not be less than three consecutive hours and that there not be more than 12 consecutive hours of discretionary interruption per day. During the calendar months of April through November, there would be no more than one discretionary interruption per day. During the calendar months of December, January, February, and March, there would be no more than two discretionary interruption events per day and such events would be separated by no less than three consecutive hours without discretionary interruption.

Q. WILL CUSTOMERS HAVE THE OPTION TO BUY THROUGH RIDER D.R.S. CURTAILMENTS CALLED BY THE COMPANIES?

A. Yes. When customers are given notice of a Rider D.R.S. curtailment event, they will also be quoted an hourly price per kilowatt hour ("kWh") that they may elect to pay in lieu of curtailing. As stated in the rider, the price for buy-through energy will never be less than $150 per megawatt hour ("MWh"). This minimum buy-through price is incorporated into the overall price offered by the Companies for service under this rider.

Q. PLEASE EXPLAIN THE CREDITS UNDER PROPOSED RIDER D.R.S.

A. Customers electing the 80 annual hours option under proposed Rider D.R.S. will be credited the product of $1.49 and their average on-peak interruptible demand each month. Customers electing the 160 annual hours option under proposed Rider D.R.S. will be credited the product of $2.34 and their average on-peak interruptible demand each month.

Q. CAN A CUSTOMER PARTICIPATE IN PJM'S DEMAND RESPONSE MARKETS IF IT IS TAKING SERVICE UNDER RIDER D.R.S.?

A. Yes. Customers taking service under Rider D.R.S. could participate in PJM's demand response market either directly or through a third party curtailment service provider ("CSP"), but only in PJM's "Emergency Capacity Only" program. Participation in the other PJM demand response programs simultaneously with the Companies' Rider D.R.S. would lead to inappropriate double payments for energy.

Q. IS THERE AN INITIAL REVENUE REQUIREMENT ASSOCIATED WITH PROPOSED RIDER D.R.S.?

A. No. Proposed Rider D.R.S. is a new program, so there are currently no customers participating at this time. As discussed by Company witness Scalzo, the Companies are proposing that the payments to customers under Rider D.R.S. and any net buy through payments from participants would be included in the Companies' ENEC because any avoided purchased power costs that will result from Rider D.R.S. will benefit customers in the ENEC. Additionally, the Companies' expect the net costs and benefits of this program to be neutral over time in the ENEC based on historic average PJM LMPs, while still providing a valuable hedge against extreme market price events.

PROPOSED COST BASIS FOR DEMAND RESPONSE CREDITS

Q. DID THE COMPANIES RELY ON THEIR OWN COST OF SERVICE INFORMATION TO DETERMINE THE PROPOSED PRICING FOR RIDER D.R.S. - RTO CAPACITY OR RIDER D.R.S.?

A. No. All of the pricing information for Rider D.R.S. – RTO Capacity and Rider D.R.S. (which is included in Company Exhibit AEV-D4) is publicly available and published on PJM's website. No information that would be contained in any Tariff Rule 42 filing schedules was utilized to calculate the proposed credits associated with Rider D.R.S. - RTO Capacity and Rider D.R.S.

Q. WHY IS THIS PRICING METHOD MORE APPROPRIATE TO USE FOR THE COMPANIES' PROPOSED DEMAND RESPONSE RIDERS THAN THE COMPANIES' RULE 42 DATA?

A. As discussed earlier, the PJM Net CONE values are appropriate because they represent net cost of building a new combustion turbine natural gas generating plant in the PJM RTO. Combustion turbine natural gas generating plants are a widely accepted proxy for incremental capacity additions. The cost of service information for the Companies that would be included in Rule 42 filing schedules would represent the embedded cost of the Companies' current capacity resources. The embedded costs of the Companies' current capacity resources may not reflect the avoided cost of the Companies' next increment of capacity. Additionally, the PJM Net CONE information is publicly available and updated annually. For these reasons the Companies propose using the PJM Net CONE information rather than the Companies' Rule 42 information as the starting point for determining the appropriate pricing for the Rider D.R.S.-RTO Capacity and Rider D.R.S. credits.

<u>INTERACTION OF RIDER D.R.S.-RTO CAPACITY AND RIDER D.R.S.</u>

Q. COULD CUSTOMERS ELECT TO TAKE SERVICE UNDER BOTH RIDER D.R.S.-RTO CAPACITY AND RIDER D.R.S.?

A. Yes. Proposed Rider D.R.S.-RTO Capacity and Rider D.R.S. represent two distinct offerings. Qualifying APCo or WPCo customers would have the option to take service under one, both, or neither of the two proposed riders.

Q. EXPLAIN HOW RIDER D.R.S.-RTO CAPACITY AND RIDER D.R.S. ARE TWO DISTINCT OFFERINGS.

A. Rider D.R.S.-RTO Capacity is strictly a PJM D.R.S. offering. Its purpose is to be a vehicle for the Companies to sign up and register demand response resources in

PJM for inclusion in their FRR plan through a standard tariff offering rather than through special contracts (as is the current practice). Because of this, the terms and conditions of Rider D.R.S.-RTO Capacity must stay aligned with those of PJM's demand response program. On the other hand, Rider D.R.S. is designed to be independent of PJM's programs with the purpose of providing a hedge for the Companies' customers in the event of extreme wholesale market price spikes.

Q. IF A CUSTOMER ELECTS TO TAKE SERVICE UNDER BOTH RIDER D.R.S.-RTO CAPACITY AND RIDER D.R.S., WHICH TARIFF WOULD TAKE PRIORITY?

A. In the event that a customer elects to take service under both Rider D.R.S.-RTO Capacity and Rider D.R.S. and APCo or WPCo calls for an interruption under Rider D.R.S. at the same time that PJM initiates an emergency interruption under Rider D.R.S.-RTO Capacity, Rider D.R.S.-RTO Capacity would take priority. Under this scenario, the customer must interrupt and would not have the option to buy through the interruption. The hours of the Rider D.R.S.-RTO Capacity interruption would not count towards the annual interruption hours of Rider D.R.S.

APPLICATION OF RIDER D.R.S.-RTO CAPACITY AND RIDER D.R.S. TO SPECIAL CONTRACT CUSTOMERS

Q. CAN THE COMPANIES' CURRENT INTERRUPTIBLE SPECIAL CONTRACT CUSTOMERS TAKE SERVICE UNDER PROPOSED RIDER D.R.S.-RTO CAPACITY OR RIDER D.R.S.?

A. Not under their current special contracts. Both Rider D.R.S.-RTO Capacity and Rider D.R.S. are available only to customers taking service under rate schedules GS, LCP, or IP. This restriction is necessary to prevent an interruptible special contract customer from being compensated twice for its interruptible capability—once through the special contract, and again under one or both of the D.R.S. riders.

Q. WHAT WILL HAPPEN IF A CURRENT INTERRUPTIBLE SPECIAL CONTRACT CUSTOMER WISHES TO TAKE SERVICE UNDER RIDER D.R.S.-RTO CAPACITY OR RIDER D.R.S.?

A. If a current interruptible special contract customer wishes to take service under one of the proposed D.R.S. riders, it will have to terminate its special contract and take service under rate schedules GS, LCP, or IP. In that event, the following ratemaking actions would take place, except for special contract customer Felman Production, LLC as discussed further by Company witness Scalzo:

1. The Companies would calculate the former special contract customer's discount to the tariff rate schedule under which it would otherwise have been served during the test year last used to set base rates. For these purposes, APCo or WPCo would use test year 2013 from Case No. 14-1152-E-42T. The discount so calculated represents the amount all customers are currently paying for that special contract customer's interruptible capacity through current base rates.

2. The 2013 test year discount for the former special contract customer would then be credited to all customers through the Companies' monthly ENEC calculations, up to the cap, as discussed by Company witness Scalzo in his testimony. This ratemaking treatment is appropriate because the credits made to customers under Rider D.R.S.-RTO Capacity and Rider D.R.S. would also be included as a charge to all customers in the Companies' monthly ENEC calculations, as also discussed by Company witness Scalzo.

Q. HOW OFTEN WILL THE PRICING INCLUDED IN RIDER D.R.S.-RTO CAPACITY AND RIDER D.R.S. BE UPDATED?

A. The Companies propose that the pricing under these riders be updated in general rate cases. Coincident with each future general rate case filing, the Companies would evaluate the pricing under these riders and may propose any needed changes. This approach should provide the Companies' interruptible customers with stable, longer-term pricing signals for interruptible capability.

Q. WILL CUSTOMERS HAVE THE OPTION OF PARTICIPATING IN PJM'S DEMAND RESPONSE MARKETS DIRECTLY OR THROUGH A CSP?

A. Yes. Rider D.R.S.-RTO Capacity and Rider D.R.S. are purely optional services. If an interruptible customer prefers to do so, it can elect to forgo taking service under the Companies' proposed D.R.S. riders and participate in PJM's demand response markets directly or through a CSP. Also, as discussed earlier, it will be possible for interruptible customers to take service under proposed Rider D.R.S.-RTO Capacity or Rider D.R.S. and still participate in certain PJM demand response markets. That said, if an interruptible customer elects to take service under both Rider D.R.S.-RTO Capacity and Rider D.R.S., the customer cannot also participate in PJM's demand response markets directly or through a CSP.

PROPOSED SCHEDULE S.B.S.

Q. DO THE COMPANIES PROPOSE A NEW TARIFF OPTION FOR SUPPLEMENTAL, BACKUP, AND MAINTENANCE SERVICE?

A. Yes. The Companies propose to make this optional schedule available to customers that have their own power production facilities, that take service under a tariff rate schedule, and that have a need for supplemental service, backup service, or maintenance service. Making this schedule available to customers would obviate the need for special contracts for this type of service. A similar tariff option has been available to APCo's Virginia customers for some time.

Q. PLEASE BRIEFLY EXPLAIN THE THREE SERVICE TYPES THAT FALL UNDER THE PROPOSED SCHEDULE FOR SUPPLEMENTAL, BACKUP, AND MAINTENANCE SERVICE.

A. The following three services will be offered under the Companies' proposed Schedule S.B.S.:

1. Supplemental Service:

Service provided to the customer to supplement the customer's power production facilities, which will enable either or both sources of supply to be utilized for all or any part of the customer's total power requirements. This service will be under rate schedules GS, LCP or IP.

2. Backup Service:

Service provided to the customer when the customer's power production facilities are unavailable due to unscheduled maintenance.

3. Maintenance Service:

Service provided to the customer when the customer's power production facilities are unavailable due to scheduled maintenance that has been approved in advance by APCo or WPCo.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR BACKUP AND MAINTENANCE SERVICE?

A. The proposed rates for maintenance and backup service were developed based on the functional revenue requirements of tariffs GS, LCP, and IP from the Companies' compliance rate filing in Case No. 14-1152-E-42T. The production function revenue requirements were adjusted for the various service reliability levels offered in proposed Schedule S.B.S. The details and calculation of the maintenance and backup service rates can be found in Company Exhibit AEV-D5.

Q. DOES THE COMPANIES' PROPOSED SCHEDULE S.B.S. CAUSE A RATE IMPACT FOR OTHER CUSTOMERS NOT TAKING S.B.S. SERVICE?

A. No. The proposed Schedule S.B.S. is an optional service that only affects those customers that choose to take S.B.S. service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

RIDER D.R.S. - RTO Capacity
(Demand Response Service)

AVAILABILITY OF SERVICE

Available for Demand Response Service (DRS) to customers that take firm service from the Company under a demand-metered rate schedule and that have the ability to curtail load under the provisions of this Rider. Each customer electing service under this Rider shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the customer's normal demand. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Rider. The customer's interruptible capacity under this Rider will be enrolled in the PJM Interconnection, L.L.C. (PJM) Load Management Demand Response Program through the Company. The Company is a member of the PJM, which is a Regional Transmission Organization (RTO). The Company further reserves the right to limit registrations should PJM restrict the Company from registering customers in any DRS Product Option, as listed on Sheet No. 27-3. The Company will take customer requests to enroll/register and to select a DRS Product Option in the order received. Customers taking service under this Rider shall not participate in any other PJM demand response program except for participating in the Regulation Market.

CONDITIONS OF SERVICE

1. The provisions of this Rider qualify under the PJM Load Management Demand Response Program as of the effective date. The Company reserves the right to make changes to this Rider in order to continue to qualify under the PJM Load Management Demand Response Program, or otherwise, as appropriate.

2. The Company reserves the right to call for mandatory curtailments of customer's interruptible load when a Pre-Emergency and/or Emergency Mandatory Load Management Reduction Action has been issued by PJM.

3. The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider. However, the customer's interruptible load shall be curtailed within 15 minutes if so requested.

4. All curtailments will apply for particular delivery years (DYs). DY, as defined by PJM and used in this Rider, means the twelve-month period from June 1 through May 31 of the following calendar year. Contract Addenda will apply to multiple DYs.

5. The customer shall not be subject to PJM initiated load curtailments (each, a PJM Event) under the provisions of this Rider beyond those required for the DRS Product Option selected by customer. The customer must agree to be subject to curtailments pursuant to the DRS Product Option selected by the customer from the table of DRS Product Options shown on Sheet No. 27-3.

6. The Company will inform the customer regarding the communication process for notices to curtail. The customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company. The customer is not responsible for non-compliance with a PJM Event if the Company fails to issue a curtailment notification for such PJM Event.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

RIDER D.R.S. – RTO Capacity
(Demand Response Service)
(continued)

7. All customer meter data required under this Rider shall be determined from 15- or 30-minute integrated metering, as applicable, based upon the customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

8. During each DY, the Company will conduct a test and verify the customer's ability to curtail as required by PJM. However, if a PJM Event for the customer's DRS Product Option is called by PJM prior to the test, then the PJM Event shall be considered the test for the DY. The Company reserves the right to re-test all customers if the Company does not achieve the minimum compliance testing standards as required by PJM. Additionally, the Company reserves the right to retest individual customers that fail to comply during a test. These tests shall be conducted for one hour on a weekday between 12 noon and 8 p.m., Eastern Time, from June 1 through September 30 during the DY.

9. If the customer fails to comply with the provisions of curtailment under this Rider, the Company and the customer will discuss methods to ensure that the customer complies during future PJM Events. If such customer compliance problems cannot be resolved to the Company's satisfaction, the Company may discontinue service to the customer under this Rider.

10. The minimum interruptible capacity contracted for under this Rider will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Rider; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

11. By March 1 of each year, the customer shall re-nominate the Interruptible Capacity Reservation for the upcoming DY. The customer may reduce the Interruptible Capacity Reservation; provided, however, that the cumulative reductions over the life of the Contract Addendum shall not exceed 20% of the original Interruptible Capacity Reservation nominated under the Contract Addendum. If no re-nomination is received by March 1, the prior DY's Interruptible Capacity Reservation shall apply for the forthcoming DY. Any increases in the Interruptible Capacity Reservation shall be subject to availability.

12. In addition to curtailments under Item 2 above, the Company reserves the right to call for the customer to curtail its interruptible load when, in the sole judgment of the Company, an emergency condition exists. An emergency condition exists if curtailment of load is necessary in order to maintain service to any of the Company's firm service customers.

13. **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS RIDER.**

RIDER D.R.S. – RTO Capacity
(Demand Response Service)
(continued)

DRS PRODUCT OPTIONS THROUGH MAY 31, 2018

DRS Product Options	Curtailment Availability	Maximum Number of Curtailments	Hours of Day Required to Respond	Maximum Duration of Curtailments	Curtailment Demand Credit $/KW – Month
Limited	Any weekday during June – September of DY	10	12 PM-8 PM	6 Hours	3.52
Extended Summer	Any day during June – October and following May of DY	Unlimited	10 AM-10 PM	10 Hours	4.10
Annual	Any day during DY	Unlimited	June- October and following May of DY (10 AM-10 PM) November-April (6 AM-9 PM)	10 Hours	4.69

Enrollment in any of the Limited, Extended Summer, and Annual DRS Product Options is subject to any limitations imposed by PJM.

DRS PRODUCT OPTIONS BEGINNING JUNE 1, 2018

DRS Product Options	Curtailment Availability	Maximum Number of Curtailments	Hours of Day Required to Respond	Maximum Duration of Curtailments	Curtailment Demand Credit $/KW – Month
Base Capacity (2018/19 & 2019/20 DY only)	Any day during June – September of DY	Unlimited	10 AM – 10 PM	10 Hours	4.10
Capacity Performance (Effective 2018/19)	Any day during DY (unless on an approved maintenance outage during October-April)	Unlimited	June-October and following May of DY (10 AM-10PM) November-April (6 AM-9 PM)	--	4.69

Enrollment in any of the Base Capacity and Capacity Performance DRS Product Options is subject to any limitations imposed by PJM.

(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
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RIDER D.R.S. – RTO Capacity
(Demand Response Service)
(continued)

EXCEPTION REQUEST TO 15-MINUTE NOTIFICATION TO CURTAIL INTERRUPTIBLE LOAD

Customers will be required to respond fully to curtailment requests within 15-minutes of notification from the Company unless an exception request has been approved by PJM and notification of such approval has been received by the Company. The exceptions, as provided by PJM and effective as of October 1, 2015, are defined directly below. Such exceptions are subject to change or modification by PJM. The intent of these exemptions is to accommodate DRS customers with legitimate, physical reasons why load reduction cannot be achieved within a 15-minute notification time period.

PJM Exception Definitions:

1. Damage (feedstock/equipment/product) - Customer's manufacturing processes requires gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process. This should represent unavoidable significant damage to feedstock, equipment or product.

2. Generator Ramp time - Transfer of load to back-up generation requires time-intensive manual process taking more than 15-minutes.

3. Safety Issue - On-site safety concerns prevent location from implementing reduction plan in less than 15-minutes.

Customers desiring to be considered for any qualifying exception (as such exceptions may change from time to time) shall complete an Exception Request Form, which will be provided by the Company upon request. The Company will submit any completed form to PJM for PJM's consideration. The Company will notify customer of PJM's approval/denial decision. If an exception request is approved by PJM, the Company will notify the customer of the approved notification time period for the next DY. PJM may require customers to apply for an exemption prior to each DY.

INTERRUPTIBLE CAPACITY RESERVATION

The customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Rider. The Interruptible Capacity Reservation shall be the customer's total Capacity Reservation less the Firm Service Capacity Reservation.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
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RIDER D.R.S. – RTO Capacity
(Demand Response Service)
(continued)

MONTHLY DEMAND CREDIT

The monthly Demand Credit shall be applicable to each month the customer is served under this Rider, regardless of whether or not there are any curtailment events during the month.

The Interruptible Demand shall be the customer's On-Peak Billing kW under the demand-metered rate schedule less the Firm Service Capacity Reservation, but not less than zero (0).

The monthly Demand Credit shall be equal to the product of the Interruptible Demand and the monthly Curtailment Demand Credit as shown on Sheet 27-3 for the customer's selected DRS Product Option.

NON COMPLIANCE DEMAND AND ENERGY

If the customer fails to comply fully with a request for curtailment under the provisions of this Rider, then a Non-Compliance Charge shall apply. If a customer is operating at or below its designated Firm Service Capacity during an event, it will be understood that the customer has no capacity available with which to comply and will not be charged a non-compliance penalty. If the metered demand during the curtailment event is above the Firm Service Capacity, the Event Non-Compliance Demand shall be equal to the average difference between the customer's metered demand and the Firm Service Capacity during all full 15 or 30 minute intervals (as applicable) of the curtailment event. Otherwise the Event Non-Compliance Demand shall be zero (0).

For the Capacity Performance DRS Product, if the metered demand during the curtailment event is above the Firm Service Capacity, the Event Non-Compliance Energy shall be equal to the cumulative amount by which the customer's metered demand exceeds the Firm Service Capacity during all full 15- or 30-minute intervals (as applicable) of the curtailment event.

ANNUAL NON-COMPLIANCE CHARGE

Charges for non-compliance under the **Limited, Extended Summer, Annual DRS Product Options** (through the 2017/18 DY), and the **Base Capacity DRS Product Option** (during the 2018/2019 and 2019/2020 DY) will be based on the customer's Non-Compliance Demand which reflects any failure by the customer to comply fully with requests for curtailment. The Annual Non-Compliance Charge shall be equal to the product of the average Non-Compliance Demand and the Curtailment Demand Credit and 12.

In the event that the Annual Non-Compliance Charge can be determined prior to the end of the DY and is greater than zero, such charge shall be assessed as a uniform offset to the monthly Demand Credit for the remaining months of the DY. If the DY has ended, the Annual Non-Compliance Charge shall be assessed as a one-time charge. Upon request, the Company may allow, but is not obligated to allow, payment of such one-time charge over a period not to exceed twelve (12) months, including interest. In no event shall the Annual Non-Compliance Charge exceed the sum of the customer's monthly Demand Credits for the DY.

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

RIDER D.R.S. – RTO Capacity
(Demand Response Service)
(continued)

MONTHLY NON-COMPLIANCE CHARGE

Beginning June 1, 2018 for the **Capacity Performance DRS Product Option**, the Non-Compliance Rate in \$/MWh will be equal to the product of Net CONE (\$/MW-day) as published by PJM and the number of days in the DY (365 or 366) divided by 30. The Monthly Non-Compliance Charge shall be equal to the product of the Non-Compliance Energy and the Non-Compliance Rate. The sum of the Monthly Non-Compliance Charges may exceed the sum of the customer's monthly Demand Credits for the DY.

SETTLEMENT

The net amount of the monthly Demand Credit and any applicable Annual or Monthly Non-Compliance Charges will be included in the customer's monthly bill for electric service under the demand-metered rate schedule.

TERM

Contract Addenda under this Rider shall be made for an initial period of four (4) DYs beginning on June 1 and ending on May 31 and shall remain in effect until either party provides three (3) years' written notice prior to March 1 of its intention to discontinue service under the terms of this Rider for the fourth DY beginning after the notice is provided. Written notice deadlines through March 1, 2019 are as follows:

Written Notice Deadline	Effective Date of End of Service under Rider
March 1, 2016	June 1, 2019
March 1, 2017	June 1, 2020
March 1, 2018	June 1, 2021
March 1, 2019	June 1, 2022

If a customer becomes ineligible for service under this Rider during the term of a Contract Addendum under this Rider, the Company may terminate such Contract Addendum immediately.

A customer having a special contract that provides for interruptible service with the Company as of the effective date of this Rider may request to discontinue that special contract service and start service under this Rider at the beginning of any calendar month, subject to the terms of the customer's existing contract and contingent upon the customer's meeting all other conditions of service under this Rider.

SPECIAL TERMS AND CONDITIONS

If a new peak demand is set by the customer in the hour following a curtailment event due to the customer's resuming the level of activity prior to the curtailment, the customer may request, in writing, that the customer's billing demand be adjusted to disregard that new peak. The Company will promptly evaluate all such requests and approve requests in its discretion, provided that such requests are reasonable. In specific circumstances and subject to reasonable conditions, the Company may approve requests in advance. Any such adjustment would affect billing under both the demand-metered rate schedule and this Rider.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

RIDER D.R.S.
(Demand Response Service)

AVAILABILITY OF SERVICE

Available for Demand Response Service (DRS) to customers that take firm service from the Company under a demand-metered rate schedule and that have the ability to curtail load under the provisions of this Rider. Each customer electing service under this Rider shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the customer's normal demand. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Rider. The Company will take customer DRS requests in the order received. Customers taking service under this Rider shall not participate in any other PJM demand response program except for the Load Management Program as a Capacity Only resource.

CONDITIONS OF SERVICE

1. The Company, in its sole discretion, reserves the right to call for curtailments of the customer's interruptible load at any time. Such interruptions shall be designated as Discretionary Interruptions and shall not exceed an aggregate number of hours of interruption during any Interruption Year. The Interruption Year shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Rider become effective on a date other than June 1, the period from the effective date of this Rider until the next May 31 after such effective date shall be referred to as the Initial Partial Interruption Year.

2. Under this Rider, the Customer must select one of the two Options identified in the table below. Each Option has a different aggregate number of hours of interruption per Interruption Year and different Demand Credits. In any Initial Partial Interruption Year, Discretionary Interruptions for each Option shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

Option	Annual Interruption Hours	Demand Credit $/kW-month
Low	80	$1.49
High	160	$2.34

3. The Company will endeavor to provide the customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 60 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption as well as the hourly Buy Through Price (as defined below). For any Discretionary Interruption, the customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the customer pays an hourly price per kWh (the Buy Through Price). The Buy Through Price shall not be less than $0.15 per kWh. Discretionary Interruptions shall begin and end on the clock hour.

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

RIDER D.R.S.
(Demand Response Service)
(continued)

4. Discretionary Interruption events shall not be less than three (3) consecutive hours and there shall not be more than twelve (12) hours of Discretionary Interruption per day. During the calendar months of April through November, there shall be no more than one (1) Discretionary Interruption per day. During the calendar months of December, January, February, and March there shall be no more than two (2) Discretionary Interruption events per day and such events will be separated by no less than three (3) consecutive hours without Discretionary Interruption.

5. If a customer is taking service under both Riders D.R.S. and D.R.S. - RTO Capacity, any interruptions called for under Rider D.R.S. - RTO Capacity shall take precedence over Discretionary Interruptions called for under this Rider and shall not count towards the customer's selected annual limit on hours of Discretionary Interruption.

6. The Company will inform the customer regarding the communication process for notices to curtail. The customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

7. The minimum interruptible capacity contracted for under this Rider will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirements under this Rider; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

8. All customer meter data required under this Rider shall be determined from 15- or 30-minute integrated metering, as applicable based on the customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

9. **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS RIDER.**

INTERRUPTIBLE CAPACITY RESERVATION

The customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Rider. The Interruptible Capacity Reservation shall be the customer's total Capacity Reservation less the Firm Service Capacity Reservation.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

RIDER D.R.S.
(Demand Response Service)
(continued)

MONTHLY DEMAND CREDIT

The monthly Demand Credit shall be equal to the product of Demand Credit per kW-Month for the customer's selected Option and the customer's monthly Average On-Peak Interruptible Demand. The customer's monthly Average On-Peak Interruptible Demand shall be the difference between the customer's Average demand during the on-peak hours of the month and the customer's Firm Service Capacity Reservation.

For the purpose of this Rider, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays, Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

MONTHLY ENERGY CHARGE

For any energy usage in excess of the customer's Firm Service Capacity Reservation during a Discretionary Interruption, the customer shall pay a Discretionary Interruption Charge at the Buy-Through Price. Such Discretionary Interruption Charge shall be in place of billing under the demand-metered rate schedule energy charge and the ENEC charge. All such energy usage shall be subject to billing under all other applicable riders.

SETTLEMENT

The net amount of the monthly Demand Credit and any monthly Energy Charge will be included in the customer's monthly bill for electric service under the demand-metered rate schedule.

TERM

Contract Addenda under this Rider shall be made for a period of one (1) Interruption Year or the Initial Partial Interruption Year and shall remain in effect for each subsequent Interruption Year until either party provides sixty (60) days written notice prior to June 1 of its intention to discontinue service effective June 1 under the terms of this Rider.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 19 (WHEELING POWER COMPANY)

SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)

AVAILABILITY OF SERVICE

Backup and Maintenance Service is available to any customer that takes service from the Company and requests such electric service for power production facilities (including renewable energy cogeneration facilities) that are designed to supply some or all of their electricity requirements and that operate in parallel with the Company's system without adversely affecting the operation of equipment and service of the Company or its customers and without presenting safety hazards to the Company or its customers. The customer shall contract for one or more of the following services:

Supplemental Service

Service provided to the customer to supplement the customer's power production facilities, which service will enable either or both sources of supply to be utilized for all or any part of the customer's total requirement.

Backup Service

Service provided to the customer when the customer's power production facilities are unavailable due to unscheduled maintenance.

Maintenance Service

Service provided to the customer when the customer's power production facilities are unavailable due to scheduled maintenance that has been approved in advance by the Company.

The Company reserves the right to limit total backup and maintenance contract capacity for all customers served under this Schedule.

CONDITIONS AND LIMITATIONS OF SERVICE

1. The conditions and limitations include, but are not limited to, the available capacity of the Company's facilities, the possibility of causing any undue interference with the Company's obligations to provide service to any of its other customers and the extent to which such backup and/or maintenance service will impose a burden on the Company's system or any system interconnected with the Company's system. For customers contracting for 1,000 kW or greater of backup service, backup service is provided on a non-firm basis during the months of January, February, June, July, August and December.

2. The Company's provision of backup and/or maintenance service to the customer is contingent upon: (i) the customer's installation, operation, and maintenance of suitable and sufficient equipment, as reasonably specified by the Company, to protect the customer's facilities and the Company's system from damages resulting from such parallel operation; (ii) the condition that the Company shall not be liable to the customer for any loss, cost, damage, or expense that the customer may suffer by reason of damage to or destruction of any property, including the loss of use thereof, arising out of or in any manner connected with such parallel operation, unless such loss, cost, damage, or expense is caused by the negligence of the Company, its agents, or employees; and (iii) the condition that the customer shall not be liable to the Company for any loss, cost,

SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)
(continued)

damage or expense that the Company may suffer by reason of damage to or destruction of any property, including the loss of use thereof, arising out of, or in any manner connected with such parallel operation, unless such loss, cost, damage, or expense is caused by the negligence of the customer, its agents, or employees.

3. If the customer has not signed a supplemental service contract, the customer will be billed for all supplemental demand in excess of either backup and/or maintenance contract capacities on the appropriate supplemental service schedule and shall thereafter be subject to the terms and conditions of said supplemental service schedule.

4. Detents shall be used on the necessary metering to prevent reverse rotation.

MONTHLY CHARGES FOR SERVICE

Supplemental Service

The customer shall contract for a specific amount of supplemental contract capacity according to the provisions of the applicable firm service schedule (hereinafter referred to as supplemental service schedule). Any demand or energy not identified as backup or maintenance service shall be considered supplemental service and billed according to the applicable schedule.

Backup Service

1. Determination of Backup Contract Capacity

The backup contract capacity in kilowatts (kW) shall be initially established by mutual agreement between the customer and the Company for electrical capacity sufficient to meet the maximum backup requirements that the Company is expected to supply.

The customer shall specify the desired backup contract capacity to the nearest 50 kW as well as the desired service reliability as specified under the Monthly Backup Charge. Changes in the backup contract capacity are subject to the provisions set forth in the Term of Contract.

2. Backup Service Notification Requirement

Whenever backup service is needed, the customer shall provide the Company notice within one (1) hour thereof. Such notification may be made orally and shall be confirmed in writing within five (5) business days and shall specify the time and date on which such use commenced and, if applicable, the time and date on which such use concluded. If such notification and confirmation thereof are not received, the customer shall be subject to an increase in contract capacity in accordance with the provisions of the Schedule under which the customer receives supplemental service and such backup demand shall be considered supplemental demand and billed accordingly.

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SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)
(continued)

3. Backup Demand Determination

Whenever backup service is supplied to the customer for use during forced outages, the customer's integrated kW demand shall be adjusted by subtracting the amount of backup contract capacity supplied by the Company. In no event shall the adjusted demand be less than zero (0). The monthly billing demand under the supplemental service schedule shall be the maximum adjusted integrated demand. If both backup and maintenance service are utilized during the same billing period, the customer's integrated demands will be adjusted for both in the appropriate period. Whenever the customer's maximum integrated demand at any time during the billing period exceeds the total of the supplemental service contract capacity and the specific request for backup and/or maintenance service, the excess demand shall be considered as supplemental demand in the determination of the billing demands under the appropriate supplemental service schedule.

4. Backup Service Energy Determination

Whenever backup service is utilized, backup energy shall be billed under the appropriate supplemental service schedule.

5. Monthly Back-up Charge

Each kilowatt of demand billed is subject to all applicable riders.

Service Voltage	% Forced Outage Rate	Maximum Outage Hours	Demand Charge $/KW
Service Reliability Level A			
Subtransmission	5	438	0.6888
Transmission	5	438	0.6666
Service Reliability Level B			
Subtransmission	10	876	1.3776
Transmission	10	876	1.3432

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SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)
(continued)

Service Voltage	% Forced Outage Rate	Maximum Outage Hours	Demand Charge $/kW
Service Reliability Level C			
Subtransmission	15	1,314	2.0564
Transmission	15	1,314	2.0098
Service Reliability Level D			
Subtransmission	20	1,752	2.7452
Transmission	20	1,752	2.6864
Service Reliability Level E			
Subtransmission	25	2,190	3.4340
Transmission	25	2,190	3.3530
Service Reliability Level F			
Subtransmission	30	2,628	4.1228
Transmission	30	2,628	4.0196

The total monthly backup charge is equal to the product of the selected monthly backup demand charge and the backup contract capacity. Whenever the allowed outage hours for the respective reliability level selected by the customer are exceeded during the contract year, the customer's unadjusted integrated demands shall be used for billing purposes under the appropriate supplemental service schedule for the remainder of the contract year.

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SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)
(continued)

Maintenance Service

1. Determination of Maintenance Contract Capacity

The customer may contract for maintenance service by giving at least six (6) months' advance written notice as specified in the Term of Contract. Such notice shall specify the amount to the nearest fifty (50) kW not to exceed the customer's maximum maintenance service requirements during planned maintenance outages and the effective date for the amount of contracted maintenance service.

2. Maintenance Service Notification Requirement

Maintenance outages may be scheduled at a time consented to by the Company. Maintenance outages will typically not be permitted during the months of January, February, June, July, August and December. Any approved maintenance outages over 1,000 kW during such months will be on a non-firm basis.

A major maintenance outage shall be considered to be any maintenance service request greater than 5,000 kW. Written notice shall be provided by the customer at least 180 days in advance of such scheduled outages or a lesser period by mutual agreement and shall specify the kW amount of maintenance service required, as well as the dates and times such use will commence and terminate. A major maintenance service request shall not exceed the kW capacity of the customer's power production facilities as listed in the customer's service contract.

A minor maintenance outage shall be considered to be any maintenance service request of 5,000 kW or less. Written notice shall be provided by the customer at least thirty (30) days in advance of such outage or a lesser period by mutual agreement.

If such notification is not received, the customer shall be subject to an increase in supplemental service contract capacity according to the provisions of the supplemental service schedule under which the customer is served and such maintenance service demand shall be considered as supplemental load in the determination of the billing demands.

3. Major Maintenance Service Limitation

The customer shall be limited to one major maintenance outage of 30-days duration for each generator listed in the customer's service contract in each contract year. Additional major maintenance outages or outages exceeding 30-days duration may be requested by the customer and shall be subject to approval by the Company. At the time at which any such additional or prolonged maintenance occurs, the customer shall provide to the Company notarized verification that energy provided under this provision is for maintenance use only.

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(See Sheet Nos. 2-1 through 2-7 for Applicability)

P.S.C. W.VA. TARIFF NO. 14 (APPALACHIAN POWER COMPANY)
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SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)
(continued)

4. Maintenance Service Demand Determination

Whenever a specific request for maintenance service is made by the customer, the customer's integrated demands will be adjusted by subtracting the maintenance service requested in the hours specified by the customer. The monthly billing demands under the supplemental service schedule shall be the maximum adjusted integrated demands.

If both backup and maintenance service are utilized during the same billing period, the customer's integrated demands will be adjusted for both in the appropriate hours. In no event shall the adjusted demand be less than zero (0).

Whenever the maximum integrated demand at any time during the billing period exceeds the total of the supplemental contract capacity and the specific request for maintenance and/or back-up service, the excess demand shall be considered as supplemental load in the determination of the billing demands.

5. Maintenance Service Energy Determination

Whenever maintenance service is used, maintenance energy shall be calculated as the lesser of (a) the kW of maintenance service requested multiplied by the number of hours of maintenance use or (b) total metered energy. Metered energy for purposes of billing under the appropriate supplemental service schedule shall be derived by subtracting the maintenance energy from the total metered energy for the billing period.

6. Monthly Maintenance Service Charge

In addition to the monthly charges established under the supplemental service schedule, the customer shall pay the Company for maintenance energy as follows:

For each kWh of maintenance energy taken:

Service Voltage	Energy Charge ¢/kWh
Subtransmission	3.881
Transmission	3.727

Each kilowatt-hour of energy consumed is subject to all applicable riders.

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SCHEDULE S.B.S.
(Standard Backup and Maintenance Service)
(continued)

Local Facilities Charge

Charges to cover interconnection costs (including but not limited to suitable meters, relays and protective apparatus) incurred by the Company shall be determined by the Company and shall be collected from the customer. Such charges shall include the total installed cost of all local facilities. In addition, the customer shall reimburse the Company for all state and federal income taxes associated with such charges. The customer shall make either a one-time payment for the Local Facilities Charge at the time of the installation of the required additional facilities, or, at its option, up to thirty-six (36) consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit or other form of security acceptable to the Company. This Local Facilities Charge Provision applies also to customers with Supplemental, Backup, and Maintenance Contract capacities less than 100kW.

SPECIAL PROVISION FOR CUSTOMERS WITH BACKUP AND MAINTENANCE CONTRACT CAPACITIES OF LESS THAN 100 kW

Customers requesting Backup and Maintenance service with contract capacities of less than 100 kW shall execute a special contract form for a minimum of one (1) year. Contract capacity in kilowatts shall be set equal to the capacity of the customer's largest power production facility.

TERM

Contracts under this Schedule will be made for an initial period of not less than one (1) year and shall continue thereafter until either party has given six (6) months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for initial periods longer than one (1) year.

A 6-months' advance written request is required for any change in supplemental, backup, or maintenance service requirements, except for the initial service contract. All changes in the service contract shall be effective on the contract anniversary date and subject to approval by the Company. The Company shall approve such changes in writing or inform the customer of any disapproval of such changes or any conditions or limitations associated with the customer's request within sixty (60) days.

SPECIAL TERMS AND CONDITIONS

At its discretion, the Company may require that Company-owned metering be installed to monitor the customer's generation.

The Company reserves the right to inspect the customer's relays and protective equipment at all reasonable times.

Customers taking service under this Schedule who desire to transfer to firm full requirements service will be required to give the Company written notice of at least thirty-six (36) months. The Company reserves the right to waive partially or entirely such notice requirement upon circumstances particular to individual customers.

Demand Response Tariff Pricing Calculations

Proposed Rider D.R.S. - RTO Capacity

30% of Avg Net CONE - Limited Product					
Planning Year (1)	Net CONE Price (2)	30% of Net CONE Price (3)=(2)x30% 0.3	Reserve Margin (4)	DR Factor (5)	Mandatory Interruption Demand Credit (6)=[(3)x(4)x(5) x 365] / [12 x 1,000 kW]
	$/MW-day	$/MW-day			$/kW-month
2014/2015	342.23	102.67	1.196	0.956	3.57
2015/2016	320.63	96.19	1.202	0.955	3.36
2016/2017	330.53	99.16	1.211	0.955	3.49
2017/2018	351.39	105.42	1.197	0.953	3.66
Average					3.52

35% of Avg Net CONE - Summer Unlimited Product					
Planning Year (1)	Net CONE Price (2)	35% of Net CONE Price (3)=(2)x35% 0.35	Reserve Margin (4)	DR Factor (5)	Mandatory Interruption Demand Credit (6)=[(3)x(4)x(5) x 365] / [12 x 1,000 kW]
	$/MW-day	$/MW-day			$/kW-month
2014/2015	342.23	119.78	1.196	0.956	4.17
2015/2016	320.63	112.22	1.202	0.955	3.92
2016/2017	330.53	115.69	1.211	0.955	4.07
2017/2018	351.39	122.99	1.197	0.953	4.27
Average					4.11

40% of Avg Net CONE - Annual Unlimited Product					
Planning Year (1)	Net CONE Price (2)	40% Net CONE Price (3)=(2)x40% 0.4	Reserve Margin (4)	DR Factor (5)	Mandatory Interruption Demand Credit (6)=[(3)x(4)x(5) x 365] / [12 x 1,000 kW]
	$/MW-day	$/MW-day			$/kW-month
2014/2015	342.23	136.89	1.196	0.956	4.76
2015/2016	320.63	128.25	1.202	0.955	4.48
2016/2017	330.53	132.21	1.211	0.955	4.65
2017/2018	351.39	140.56	1.197	0.953	4.88
Average					4.69

Demand Response Tariff Pricing Calculations

Proposed Rider D.R.S.

Hours of Interruption (1) (Hours)	Average Hourly Market Prices[1] (2) ($/MWh)	Adjusted Average[1] (3)=(2)x95% ($/MWh)	Market (4)=(1)x(3)x1MW ($/MW-year)	Energy Charge[2] (5)=(1)x1MW x $ 34.03 ($/MW-year)	Annual Cost (6)=(4)-(5) ($/MW-year)	Discretionary Interruption Demand Credit (7)=(6)/(12x 1,000 kW) ($/kW-month)
80	$ 271.63	$ 258.05	$ 20,643.86	$ 2,722.40	$ 17,921.46	$ 1.49
160	$ 220.75	$ 209.71	$ 33,553.47	$ 5,444.80	$ 28,108.67	$ 2.34

[1] Average market prices are RT system energy prices with a minimum of $150/MWh included
[2] Current Tariff LCP Trans Energy Charge

PJM Real Time System Energy Prices		
Year	Top 160 Hours	Top 80 Hours
2011	$ 190.11	$ 228.37
2012	$ 170.50	$ 190.99
2013	$ 172.35	$ 194.70
2014	$ 384.46	$ 521.75
2015	$ 186.31	$ 222.34
Average	$ 220.75	$ 271.63

APPALACHIAN POWER COMPANY & WHEELING POWER COMPANY
West Virginia Standby Service (SBS) Rate Design
Revenue Requirements and Billing Units from Compliance Filing in Case No. 14-1152-E-42T

I. Target Base Revenue	Non-ENEC Production Energy	Non-ENEC Production Demand	Non-ENEC Total
GS	-$9,558,654	$123,921,584	$114,362,910
LCP	-12,213,328	155,440,940	$143,227,612
IP	-2,259,924	40,469,464	$38,209,540
Total	-$24,031,906	$319,831,968	$295,800,062

II. Determinants	Loss-Adjusted CP Demand
Secondary	5,439,976
Primary	2,972,503
Subtransmission	3,095,344
Transmission	2,540,414
Total	14,048,237

III. Generation Energy Rate	GS - Block 1 Energy Rate	GS Block 1 Billing Energy	LCP Energy Rate	LCP Billing Energy	IP Energy Rate	IP Billing Energy	Energy Revenues
Secondary	0.03582	2,211,111,292	0.00738	174,738,390	0.00337	11,271,720	$80,529,561
Primary	0.03479	224,375,527	0.00718	1,432,015,070	0.00327	81,932,100	$18,355,811
Subtransmission	0.03453	20,086,232	0.00713	1,518,691,667	0.00325	396,743,753	$12,811,266
Transmission	0.03388	878,843	0.00700	945,003,376	0.00319	750,045,254	$9,037,443
Total		2,456,451,894		4,070,448,503		1,239,992,827	$120,734,081
Adjustment to Energy Revenue							$144,765,987

IV. Demand-Based Rates	Production Energy	Production Demand	Total
Target Generation Revenues	-$24,031,906	$319,831,968	$295,800,062
Adjustment	144,765,987	(144,765,987)	0
Adjusted Target Generation Rev	$120,734,081	$175,065,981	$295,800,062
Billing Loss-Adjusted Demand		14,048,237	
Demand Rates at Generation		$12.46	

IV. Demand-Based Rates (cont'd)	Loss Factor	Demand Rate	Production Demand
Subtransmission	1.05562	$12.46	13.15
Transmission	1.03349	$12.46	12.88

V. Demand Charges @ Service Reliability Levels	Forced Outage Rate	Production Demand	Production Demand
Service Reliability Level A			
Subtransmission	5.0%	13.15	0.66
Transmission	5.0%	12.88	0.64
Service Reliability Level B			
Subtransmission	10.0%	13.15	1.32
Transmission	10.0%	12.88	1.29
Service Reliability Level C			
Subtransmission	15.0%	13.15	1.97
Transmission	15.0%	12.88	1.93
Service Reliability Level D			
Subtransmission	20.0%	13.15	2.63
Transmission	20.0%	12.88	2.58
Service Reliability Level E			
Subtransmission	25.0%	13.15	3.29
Transmission	25.0%	12.88	3.22
Service Reliability Level F			
Subtransmission	30.0%	13.15	3.95
Transmission	30.0%	12.88	3.86

VI. Maintenance Energy Charge	
Total Demand Component (@ 15%)	**Generation**
Subtransmission	$1.97
Transmission	$1.93
Hours @ 85% Load Factor	621
Demand Components per KWH	
Subtransmission	0.00317
Transmission	0.00311
Generation Energy	**Total**
Subtransmission	0.00713
Transmission	0.00700
Maintenance Energy Charge ($/KWH)	**Total**
Subtransmission	$0.01030
Transmission	$0.01011