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BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
EVERETT G. PHILLIPS

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

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I. INTRODUCTION

Q. Please state your name, business address and position.

A. My name is Everett G. Phillips. My business address is 12333 Kevin Avenue, Ashland, Kentucky 41102. I am the Director of Customer and Distribution Operations for the Kentucky Power Company (KPCo).

Q. Please briefly describe your educational background and professional experience.

A. I earned a bachelor's degree in Electrical Engineering in 1985 from West Virginia University. I am a registered professional engineer in the state of Kentucky. I am a member of the National Society of Professional Engineers (NSPE). I am a member of the applied process technologies advisory committee for the Ashland Community and Technical College. I joined Appalachian Power Company in 1985 as a distribution engineer in Huntington, West Virginia. In 1994, I became an area line supervisor in Clintwood, Virginia. I moved to Kentucky in 1998 to become the KPCo Pikeville district superintendent. In 2000, I was promoted to Pikeville district manager. In 2004 I moved to Ashland, Kentucky where I was named to my current position.

Q. What are your responsibilities as Director of Customer and Distribution Operations?

A. I am responsible for overseeing the planning, construction, operation and maintenance of KPCo's distribution system. My duties include the oversight and management of service extension to new customers, the safe and reliable delivery of service to our customers and the restoration of service when outages occur. My responsibilities also include overseeing KPCo's distribution system vegetation management program.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of KPCo's current power quality and service reliability programs. I will explain the increase in customer expectations for better power quality and reliability and will then present the Reliability and Service Enhancement Plan (Plan) and associated rate adjustment. The proposed rate adjustment is required to fund four programs designed to modernize and improve KPCo's energy-delivery distribution infrastructure to better meet our customers' growing reliability needs. The four programs I will discuss in detail include 1) Enhanced Vegetation Initiative, 2) Enhanced Equipment Inspection & Mitigation, 3) Distribution Workforce Planning Initiative, and 4) gridSMART^{sm} Initiative. Additionally, I will discuss the Kentucky Public Service Commission Report on the September 2008 Wind Storm and the January 2009 Ice Storm (Ike and

Ice Report) and how our proposed adjustment supports the Commission's recommendations.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. I am sponsoring the following exhibit attached to my testimony:

Exhibit	Description
EXHIBIT EGP-1	Summary of Reliability and Service Enhancement Adjustment

III. CURRENT DISTRIBUTION RELIABILITY PROGRAMS

Q. Please describe KPCo's Distribution system that serves Kentucky customers.

A. KPCo serves approximately 175,000 retail customers in Kentucky in a service area that covers approximately 3,780 square miles. KPCo's distribution system includes some 9,930 pole miles of primary and secondary voltage lines. KPCo delivers reliable electric service to our customers by having adequate distribution facilities in place and by protecting those facilities from hazards that interrupt service.

Q. What are the principal causes of service interruptions?

A. As shown below in Figure 1, the principal causes of service interruptions on KPCo's system during the test year and the previous three years, excluding events such as major storms, were tree related contacts and equipment failures.

Figure 1: Outages Records by Cause

	12M- September 2009	2008	2007	2006
Trees	37.5%	39.0%	31.8%	37.3%
Equipment	22.8%	23.3%	25.5%	24.4%
Animal	9.1%	6.8%	8.3%	9.3%
Scheduled	7.2%	7.2%	8.9%	5.4%
Lightning	3.1%	2.3%	4.1%	5.6%
All Other	20.3%	21.5%	21.3%	18.1%

Tree related failures caused approximately 38 percent of sustained, non-major event outage records on the KPCo system during the period of twelve months ending September 2009, while equipment failures caused approximately 23 percent. Equipment failures include cutouts, arresters, insulators, crossarms, connectors, etc.

Q. How does KPCo currently maintain reliability on its distribution system?

A. KPCo uses a combination of programs to maintain its distribution infrastructure. These programs are designed to minimize the impact of service interruptions to customers and can be divided into three major categories:

1) Distribution Asset Management;

2) Major Distribution Reliability and Capacity Additions; and

3) Distribution Vegetation Management.

Q. Describe KPCo's Distribution Asset Management Programs.

A. The Distribution Asset Management Programs are designed to maximize the efficiency of expenditures and optimize system performance. KPCo has nine Asset Management Programs. The programs and their roles with respect to distribution system are as follows:

1. Overhead Circuit Facilities Inspection and Maintenance Program: Under this Asset Management Program, KPCo visually inspects its overhead facilities to identify and correct potential problems before they can lead to an outage. As a result of identifying and repairing such potential problems, KPCo's customers experience fewer and shorter service interruptions.

2. Animal Mitigation Program: The objective of this Asset Management Program is to reduce the number of animal-caused outages by installing animal guards on line transformers and other line equipment at locations that have had, or potentially may have, a high risk of animal-caused outages.

3. Underground Facilities Inspection and Maintenance Program: Under this Asset Management Program, KPCo visually inspects the external, above-ground portions of underground distribution facilities to identify and correct problems before they can cause an outage. Through these inspections, KPCo identifies and repairs such things as transformers, pedestals, and switchgear.

4. Pole Inspection and Maintenance Program: The primary objective of this Asset Management Program is to maintain and prolong the mechanical integrity of KPCo's wood poles. As necessary, poles are treated, treated and reinforced, or replaced. This Asset Management Program helps KPCo identify and replace poles that might otherwise fail and cause power interruptions.

5. Recloser Maintenance / Replacement Program: The objective of this Asset Management Program is to perform preventive maintenance on reclosers, or to replace, as needed, units that are not operating properly. When a recloser device senses a fault, the device will automatically open and allow a brief period of time for the cause of the fault to clear from the line. The reclosing equipment will then automatically re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service.

6. Overhead Conductor Program: This Asset Management Program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of wear. This Asset Management Program targets areas that are experiencing above-average interruptions.

7. Underground Cable Program: The objective of this Asset Management Program is to correct underground primary cable deficiencies by restoring the integrity of cable through either cable injection or cable replacement. As is the case with KPCo's Overhead Conductor Program, this Asset Management Program targets areas experiencing above-average interruptions and lessens the likelihood of future interruptions to our customers.

8. Lightning Mitigation Program: The objective of this Asset Management Program is to reduce the number of lightning-caused outages through the installation of new lightning arresters at locations within areas known to be prone to lightning-caused outages.

9. Sectionalizing Program: This Asset Management Program improves the reliability of KPCo's distribution circuits by adding new, or modifying existing, sectionalizing devices. These sectionalizing devices may be manual pole top switches or automatic devices such as reclosers or fused cutouts. The addition of manual switches where warranted allows the outage duration to be lessened for some of the customers, as the unaffected portions of the circuit can be reenergized. Fused cutouts or reclosers work to remove a faulted section of the circuit from service and prevent the entire circuit from experiencing a sustained outage. This enhanced sectionalizing capability results in smaller circuit segments and fewer customers being interrupted due to faults that may occur on distribution circuits.

Q. Please describe what is included in the Major Distribution Reliability and Capacity Additions Program.

A. Each year, KPCo undertakes various major distribution reliability improvements in addition to those included in the Asset Management Programs I previously described.

For instance, in 2008, in Floyd County, KPCo converted a 12 kV circuit to 34.5 kV in order to handle the load growth as well as create a backup source for an existing 34.5kV circuit. Additionally, in the 2008 and 2009 timeframe, KPCo installed three distribution automation systems to enable automatic sectionalizing detection of a fault. This was done in order to operate and isolate the fault, thus minimizing the number of customers that may be negatively impacted by a sustained outage. The three systems installed were located in 1) Martin County (Inez area), 2) Boyd County (Cannonsburg area), and 3) Perry County (Buckhorn area). KPCo also completed improvements to prevent overloading of equipment and to enhance its ability to restore power to customers throughout the territory. These improvements include construction of new distribution feeder ties, the relocation of inaccessible circuit lines, and the addition of Softshell Station, in Knott County, to relieve a capacity issue at Beckham Station.

KPCo's proactive planning efforts identify areas where the increasing demand for electricity is approaching the limit of the distribution system's current capacity. The reliability improvement projects installed to serve this load growth also upgrade, improve, and effectively maintain KPCo's distribution system. These specific projects re-conductor portions of the existing distribution circuits or allows portions of a circuit to be reconfigured. The expansion of the distribution system to serve new customers can also result in the upgrade or replacement of distribution facilities to maintain and enhance reliable service to KPCo's customers.

Q. Now please describe KPCo's current Distribution Vegetation Management Program.

A. KPCo's existing distribution vegetation management program employs a performance-based approach, which prioritizes work on KPCo's facilities after taking into consideration a number of input variables. These variables include the time elapsed since vegetation management activities were last performed; the results of recent line inspections; tree-related reliability performance; critical customer service needs such as fire stations, police departments and hospitals; and environmental conditions. KPCo has used the performance-based approach for many years to allocate resources to particular circuits, or portions of circuits. KPCo uses a variety of vegetation management practices to control vegetation along its distribution rights-of-way, such as aerial sawing, mechanized trimming, manual trimming (roping and hand climbing), and herbicide applications. The program is dynamic and flexible and is intended to respond to local needs that may arise.

KPCo's vegetation management practices are conducted in accordance with standards established by the American National Standards Institute (ANSI), the Occupational Safety and Health Administration (OSHA), and the National Electrical Safety Code (NESC), and include such things as pruning and removing trees; safety and worker protection; work clearances and training requirements; and safety clearance guidelines.

IV. CUSTOMER EXPECTATIONS

Q. Is KPCo providing safe and reliable service to its customers?

A. Yes. KPCo's Distribution Asset Management, Major Distribution Reliability and Capacity Additions, and Vegetation Management Programs are designed to ensure that customer expectations are satisfied by the Companies' ability to provide safe and reliable service.

Q. How satisfied are customers with KPCo's overall service reliability?

A. KPCo conducts quarterly customer satisfaction tracking studies for both residential and small commercial customers. These studies are conducted by Market Strategies, Incorporated (MSI). Using this independent survey firm assures the integrity and quality of the data and provides comparative national benchmarking data on standardized questions included in the surveys.

The residential study is administered by telephone using random-digit-dialing within the telephone exchanges located in our service territory. The smaller commercial study also uses a telephone methodology, with sampling of commercial customers with demands of less than 750 kW. Each year about 400 residential and small commercial customers are surveyed.

KPCo's reliability-related customer satisfaction regularly scores above the MSI-supplied national benchmark. This is especially true with respect to small commercial accounts. KPCo's small commercial customers indicated high levels of satisfaction in 2008 for overall service reliability (93 percent), outage restoration (92 percent), and power quality (91 percent). These customers were also substantially more satisfied in 2008 than the MSI national average of each of these measures -

overall service reliability (+5 points), outage restoration (+13 points) and power quality (+10 points).

The level of KPCo's 2008 reliability-related residential customer satisfaction, while slightly down from 2007, is still quite high. KPCo's residential customer satisfaction levels, compared to the MSI national average, were at 87 percent for overall service reliability (at the national average), 88 percent for outage restoration (11 points above the average), and 87 percent for power quality (7 points above the average).

Q. Have there been any recent reports published by the Commission related to customer expectations?

A. Yes, the Kentucky Public Service Commission's Ike and Ice Report was recently issued. This report reviews the performance of the utilities in the Commonwealth of Kentucky during the September 2008 wind storm and the January 2009 ice storm. The report draws from consumer complaints and comments made to the PSC.

Q. How does KPCo plan to close the gap and ensure that the reliability of its distribution facilities are aligned with customers' increased expectations?

A. Continued focus on current level of distribution reliability improvement programs can take the reliability of a distribution system only so far. To reach a higher level of reliability, KPCo has developed and is proposing a long term Reliability and Service Enhancement Plan focusing on reliability and service enhancement initiatives to address increasing customer expectations, the Commission's Ike and Ice Report recommendations, and a deteriorating distribution system.

V. PROPOSED RELIABILITY AND SERVICE ENHANCEMENT PLAN

Q. What is the purpose of this section of your testimony?

A. In this section, I will: 1) discuss the need to improve reliability on KPCO's distribution system; 2) propose a Reliability and Service Enhancement Plan to meet this need; and 3) explain the benefits and costs associated with the execution of this proposed Reliability and Service Enhancement Plan (Plan). The Plan includes a: 1) Enhanced Vegetation Initiative; 2) Enhanced Equipment Inspection and Mitigation Initiative; 3) Distribution Work force Planning Initiative; and 4) gridSMART Initiative.

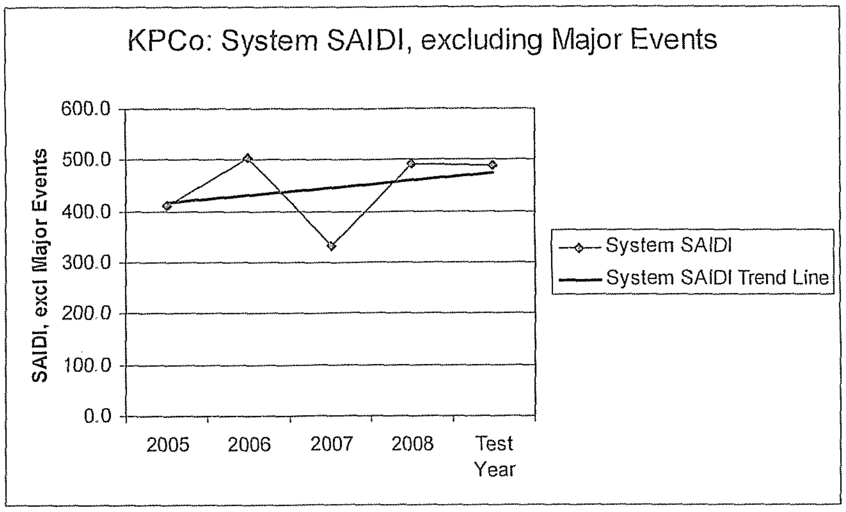
Q. Why is KPCo proposing a Reliability and Service Enhancement Plan?

A. KPCo is proposing a Reliability and Service Enhancement Plan to address the following concerns:

1. Deteriorating reliability trend: Reliability will become increasingly difficult to improve or even maintain unless KPCo implements a Reliability and Service Enhancement Plan which will require additional funding. KPCo has already experienced an increase in System Average Interruption Duration Index (SAIDI[1]) from 2005 through the end of the test year as indicated in Figure 2 below.

[1] SAIDI indicates how long the average customer is without service due to sustained interruptions during the specified period. It is the number of customer-minutes of interruption divided by the number of customer served.

Figure 2: Increased System SAIDI



2. Increased customer expectations: due to the heightened awareness resulting from recent storms and the increased use of digital technology, KPCo's customers have an increasing expectation and need for enhanced reliability and service quality. The results from a 2008 customer survey performed by MSI show that approximately 27 percent of residential survey respondents and 25 percent of small commercial survey respondents believed their service reliability expectations would increase over the next five years; and

3. Support of the Ike and Ice Report: increased reliability efforts align with the recommendations from the Ike and Ice Report.

Part 1: Enhanced Vegetation Initiative

Q. Please state the purpose of the Enhanced Vegetation Initiative.

A. The purpose of the Enhanced Vegetation Initiative is to improve the customer's overall service experience by reducing tree-related interruptions and/or sustained outages to our customers. This can be accomplished by moving from a performance-based to a more cycle-based approach regarding vegetation management.

Q. What is the difference between performance-based versus a cycle-based approach to vegetation management?

A. The performance-based approach allocates labor and financial resources to areas where tree-related outage concerns exist. Therefore, under the current performance-based program, it is common that a circuit may not be completely cleared end-to-end for some number of years. In contrast to this approach, a cycle-based program allows trees along lines to be regularly maintained on a periodic time continuum with the flexibility to address areas of concern that may arise. KPCo proposes that the vegetation management program be in a four-year cycle.

Q. Will the cycle-based vegetation management approach improve reliability? Explain.

A. Yes. A cycle-based approach to vegetation management will improve reliability over time because the cycle approach involves evaluating KPCo's entire distribution system within a four-year period. The evaluation provides data that allow plans to be developed for trimming trees so that within a four-year cycle period tree vegetation should not grow back into the power lines.

Q. Explain further what additional work would be completed with the incremental funding for the Enhanced Vegetation Initiative.

A. With the proposed additional funding, KPCo would be able to move from a reactive vegetation management program to a more proactive vegetation management program. With a four-year cycle, KPCo would evaluate 25 percent of its distribution system on an annual basis. Evaluating 25 percent of the miles, annually, would allow a more systematic, data-driven approach to maintaining the system from a vegetation management viewpoint.

This evaluation process would allow KPCo to achieve a cyclic vegetation management program to perform the necessary vegetation clearing. With this evaluation, identified areas would be maintained as needed and an inspection and analysis of the entire distribution system would be continually conducted over a rolling four-year period. However, depending on the field data obtained and the rainfall in a particular area, some line miles may be maintained on a three-year interval, while maintenance on others may stretch to every four to six years.

Q. **How would KPCo begin to implement a four-year vegetation management cycle?**

A. The proposed four-year cycle approach would be deployed over a five-year transition period. First, KPCo would create a vegetation profile to collect, store, predict, inventory species tree growth rates and analyze specific vegetation data. For instance, the location of vegetation in proximity to the conductors, accessibility, density, vegetation coverage (e.g., vines), and vegetation growth rates are all input variables which are critical in the reliability planning process. This vegetation profile would then be used to establish work plans for each circuit (or portions of a circuit) under a vegetation management schedule. Some locations would require more frequent management, while management in other areas may be less frequent, depending on a number of factors. For instance, this profiling effort would provide sufficient information for trimming between distribution power lines and trees so that within the four-year cycle period tree vegetation should not grow back into power lines, thus reducing outages and increasing overall reliability. The initial plan would require five years of transition to a continual four-year cycle primarily because the first year will require time to complete the first inventory cycle as well as secure the additional tree crews.

Q. Does the KPCo service territory exhibit characteristics that indicate a need for additional vegetation management?

A. Yes. As mentioned earlier, line contact with trees is the largest cause of outages. This is due to the heavy vegetation and the type of terrain that exists throughout KPCo's hilly and mountainous service territory. Tree outages are caused by vegetation both in and out of the right-of-way. Also, animal-caused outages are attributable to trees because tree limbs provide small animals a natural path to electrical facilities.

Additionally, as shown in Figure 3 below, KPCo has seen an increase of approximately 6 percent in customer reports called IO-13 since 2007. An IO-13 is an Investigation Order initiated by a customer who is concerned with some aspect of KPCo's vegetation management program. This 6 percent increase in customer vegetation reports supports the timing of KPCo's increased vegetation management proposal.

Figure 3: Increase in Vegetation-Related Investigation Orders

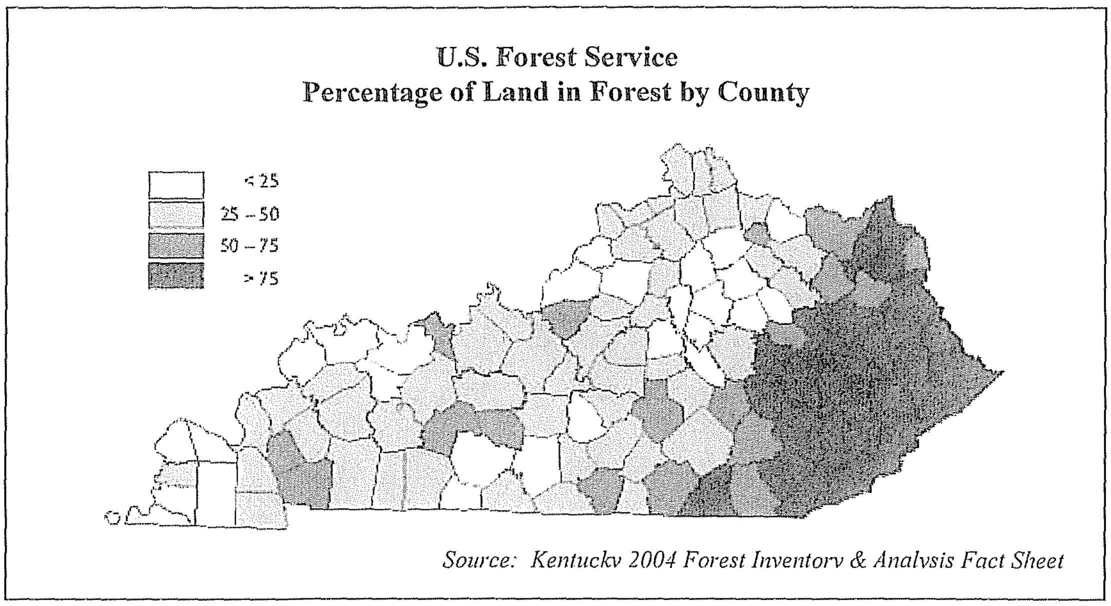
Year	IO-13
2009 (projected)*	2389
2008	2303
2007	2268

Note: 2009 data is 11 months actual and 1 month projected

Q. Please discuss the conditions caused by heavy vegetation which demonstrate the need for additional vegetation funding?

A. The majority of KPCo's distribution lines, both primary and secondary, are located in rural areas that have the heaviest concentration of vegetation. The United States Department of Agriculture issued a Land Distribution Map in 2004 that indicates the eastern portion of Kentucky has heavy concentrations of vegetation. Figure 4 below demonstrates that the forestry density varies greatly from relatively low density in the western portion of the state to the heavy concentrations in the east. All 20 counties that KPCo serves are characterized by having greater than 50 percent of heavy vegetation density with 80 percent of these counties having greater than 75 percent heavy vegetation density.

Figure 4: Forest Land Distribution for State of Kentucky



Q. What rights-of-way clearing efforts would take place under the proposed Reliability and Service Enhancement Plan?

A. To illustrate the scope of the Reliability and Service Enhancement Plan, I have prepared Figures 5 and 6 which summarize the work units associated with the vegetation management activity, including the acres of brush cleared and our projections for these activities in the first five years of the enhanced Plan. The projections are based on a statistical sample. The first two years will be a building process to increase staff, train additional crews, however the tree crews will begin to trim 682 percent more trees and increase tree removal by 16 percent on a yearly basis. The next three years the amount of trees trimmed will increase 916 percent and tree removal will increase 50 percent. After the 5-year transition period, the distribution system will have been cleared and inventoried; KPCo expects the number of tree crews to decrease as the four-year cycle is continued.

Figure 5: Actual Distribution Rights-of-Way (ROW) Summary

KPCo Actual ROW Summary Report			
Year	Trees Trimmed	Trees Removed	Acres of Brush Cleared
2006	25,589	79,856	628
2007	22,747	112,758	619
2008	25,186	111,445	535

Figure 6: Projected Distribution ROW Summary

Transition to Cycle-based Vegetation Management Program Incremental Work to be Performed			
KPCo Projected ROW Summary Report			
Year	Trees Trimmed	Trees Removed	Acres of Brush Cleared
Year 1	197,000	129,000	2,900
Year 2	228,000	149,000	3,300
Year 3	237,000	155,000	3,500
Year 4	247,000	162,000	3,600
Year 5	256,000	168,000	3,800

Q. Does the proposed Enhanced Vegetation Initiative complement the Ike and Ice Report issued on November 19, 2009?

A. Yes, recently, the Kentucky Commission published the results of a joint review of utility performance during and following both the September 2008 wind storm, which was caused by Hurricane Ike, and the January 2009 ice storm. The Ike and Ice Report specifically addressed topics that are relevant to KPCo's current proposed Reliability and Service Enhancement Plan, including KPCO's recommendations for new vegetation management activities.

Q. Would you please summarize the Report's conclusions regarding vegetation management?

A. The Report states that a program that addresses trees outside of the utility's ROW "has the potential to reduce weather-related outages." The Commission felt utility vegetation management practices did not adequately address the potential damage that could be caused by trees outside the ROW. Referencing a study by Davies Consulting, the Report supports the aggressive removal of diseased or damaged trees (hazard trees) outside the ROWs that have a high probability of breaking and falling into lines.

Q. Does KPCo agree with the Ike and Ice Report?

A. KPCo agrees with the recommendation to include activities in its vegetation management program that address trees outside of the ROWs, specifically hazard trees. KPCo's proposal includes an incremental capital component of $2.04 million for the removal of large hazard trees and widening of the ROWs. KPCo will also be more aggressive with property owners to gain access to the hazard trees outside of the existing ROWs. A hazard tree is defined by the United States Department of Agriculture as "a tree with structural defects likely to cause a failure of all or part of the tree, which could strike a target." A complete vegetation management program must not ignore hazard trees, even those outside the ROWs.

Q. What elements besides inventorying tree species growth rates would change or become incremental to KPCo's current vegetation management program?

A. KPCo is proposing to more than double the vegetation management crews and support personnel in implementing a cycle-based vegetation program. This will create jobs for the state of Kentucky. Currently KPCo has approximately 73 crews; under the proposal, this number will increase to roughly 150. KPCo typically employs a range of two to five employees per crew. The additional crews will perform end-to-end tree trimming, tree removals and widening of ROW where possible for all of KPCo's distribution circuits.

Q. What will be the key customer benefits from KPCo implementing a four-year cycle vegetation management program?

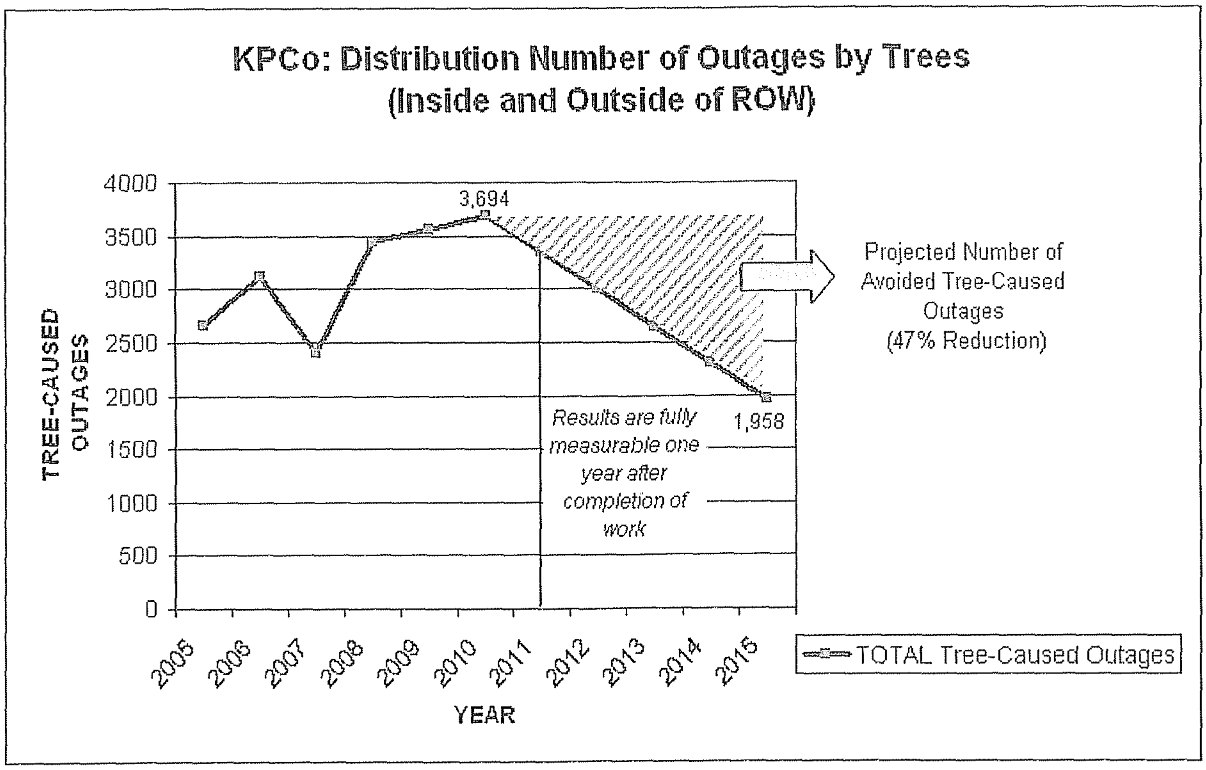
A. The key benefits for KPCo's customers are a reduction in sustained tree related outages, improved power quality with fewer momentary interruptions from trees contacting power lines, and faster restoration after storm outages. Hazard trees outside the ROW will be addressed through identification and removal, further improving reliability.

Customers will benefit from faster restoration after all storms. As the ROWs are widened and trees and brush are removed, crews will have improved access to address the cause of the outage. The identification process will provide data that will feed into the creation of annual work plans used on all circuits - especially on the worst-performing circuits.

Q. What is the time frame in which customers will realize these benefits?

A. Figure 7 below indicates a 47 percent projected reduction in customer tree-caused sustained outages for the circuits cleared under the enhanced program. The 47 percent estimated reduction in outages is based upon field observations of actual reductions experienced from recent circuit re-clearing activities. The benefits of the reliability enhancement plan can be measured approximately one year after the mitigation work has been completed. However, customers will recognize the power quality and reliability benefits immediately once the work has been completed on their circuit.

Figure 7: Forecasted Number of Avoided Tree-Caused Outages



Note: 2010 shows increase due to start-up not occurring until second half of year.

Q. Has the customer benefit of a four-year vegetation cycle been demonstrated in any other AEP service territories?

A. Yes. The customer benefit of such a plan is demonstrated by the experience of Public Service Company of Oklahoma (PSO), an AEP affiliate, which is progressing towards a four-year trimming cycle. PSO's efforts are funded through a reliability rider. PSO is on track to complete its first four-year tree trimming cycle by late 2010. PSO has completed vegetation management activities on approximately 87 percent of its existing overhead distribution system, which represents work either completed or in progress on 622 circuits and 10,841 line miles. Since PSO began this effort, reliability has improved significantly. For the 12-months ending October 2009, PSO experienced a 58 percent reduction in customer outages due to sustained, non-major event tree-related outages, compared to the 12-months ending December 2004, which was the year before the reliability program was initiated.

Q. Are you aware of any studies that indicate a four-year vegetation management cycle is an industry standard practice?

A. Yes. In 2005, the Edison Electric Institute sponsored a survey and study by Davies Consulting regarding state reliability regulation in the United States. The Davies review of vegetation practices by 18 investor-owned utilities serving customers in 39 states showed a four-year tree trimming cycle to be a common benchmark for vegetation management programs.

Q. What has been the historical level of KPCo's distribution vegetation management expenditures?

A. The distribution vegetation funding provided in the last rate case was $5.7 million in O&M and $1.79 million in Capital. Figure 8 below summarizes KPCo's distribution vegetation management's spending levels since 2005, excluding major storm expenses.

Figure 8: Historical Distribution Vegetation Management Spend

KPCo's Historical Distribution Vegetation Management Spend ($ Millions)			
Year	**O&M**	**Capital**	**Total**
TYE 6/30/05	$5.70	$1.79	$7.49
2005	$6.88	$1.88	$8.76
2006	$7.39	$2.56	$9.95
2007	$6.95	$3.06	$10.01
2008	$7.17	$2.54	$9.71
TYE 9/30/09	$7.24	$2.04	$9.28

Q. Is KPCo able to maintain its level of service reliability at current spending levels?

A. No. As shown above in Figure 8, KPCo has increased vegetation management spending 24 percent from the last approved rate case in 2005 until twelve months ending September 30, 2009. But absent a significant increase in spending the number of total trees trimmed or removed in KPCO's service area will decrease in future years, given inflation and the rise in labor and commodity pricing. KPCo has incurred, and will continue to incur, cost escalations in material and contract labor related to providing distribution services. Specifically, the costs for material, trucks, equipment, spray and labor have increased by 15 percent over the past 4 years since KPCo's last rate case.

Q. Has KPCo performed any expense projections to fully achieve a cycle-based approach in vegetation management?

A. Yes. As mentioned earlier, KPCo has approximately 9,930 pole miles of primary and secondary voltage lines. KPCO's total average annual cost estimate for vegetation management under the Plan is $25.89 million. The estimate was based on actual line mile tree-trimming clearing expenses, which include base tree trimming work, herbicide application, and incremental tree trimming crews to perform end-to-end clearance, administrative oversight, and follow-up trimming for fast growing vegetation between cycles.

Q. What is the cost associated with the proposal to move to a four-year cycle?

A. As depicted in Figure 9 below, the projected incremental additional O&M cost associated with this proposal ranges from $13.93 million in year one to $16.58 million in year five. Additionally, KPCo's incremental capital cost will range from $1.84 million in year one to $2.69 million in year five.

Figure 9: Projected Incremental O&M Cost and Incremental Capital Cost for Four-Year Cycle ($000)

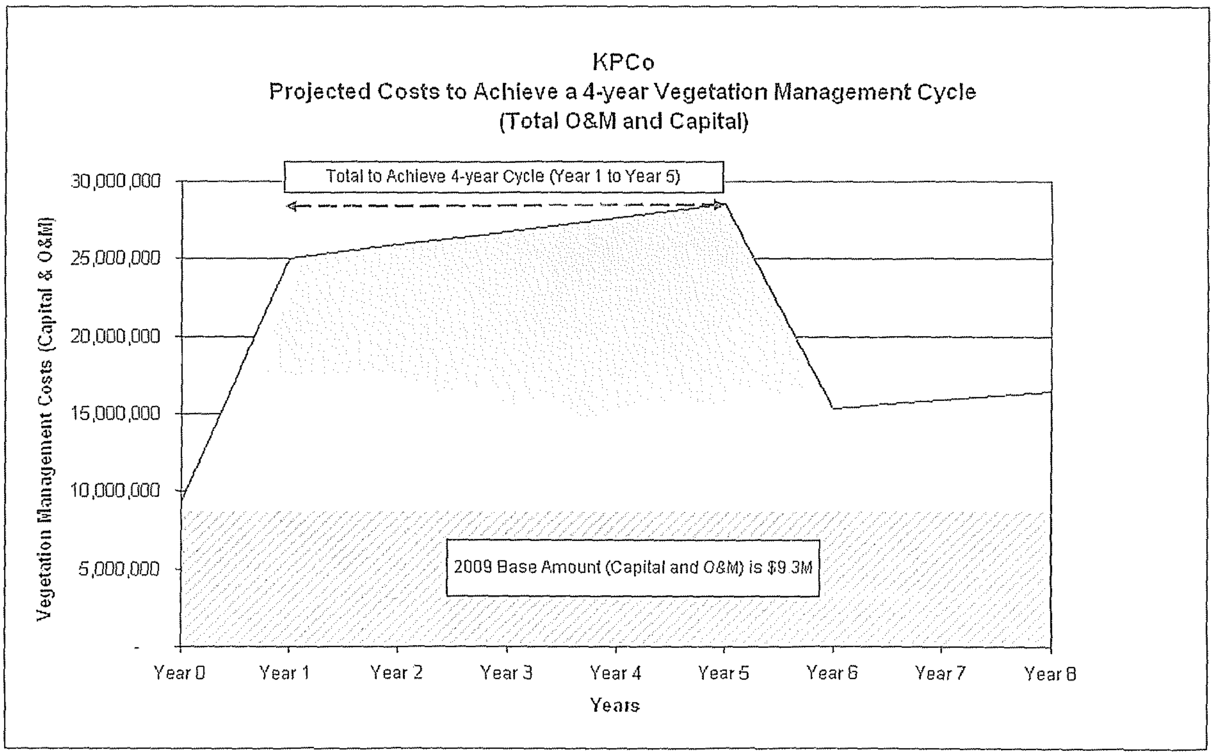
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental O&M	13.93	14.56	15.22	15.89	16.58	5.18	5.55
Incremental Capital	1.84	2.04	2.24	2.46	2.69	0.91	1.06
Total	$15.77	$16.60	$17.46	$18.35	$19.27	$6.09	$6.61

Note: The data in Figure 9 is incremental to base amounts (TYE: 9/30/09), which totals $9.28M: $2.04M Capital and $7.24 O&M.

Q. What are the long-term cost projections associated with this Enhanced Vegetation proposal?

A. The long-term projections demonstrate that the proposed Enhanced Vegetation Initiative will allow KPCo to maintain reliability at a decreased ongoing cost once a four-year cycle is achieved. Figure 10 depicts the projected total O&M and Capital costs associated with implementing the proposed Enhanced Vegetation Initiative.

Figure 10: Projected Costs to Achieve a 4-year Vegetation Management Cycle



As you can see from the chart above, once the desired vegetation management cycle has been achieved in year five of the program, ongoing maintenance costs are expected to decrease significantly and settle in at a reduced amount.

Q. Please explain the process used to identify the cost associated with obtaining a four-year distribution vegetation management cycle?

A. American Electric Power Service Company (AEPSC) Distribution Services Department provided an estimate to achieve a four-year vegetation management cycle for KPCo distribution system. The model was developed specifically to calculate the funding needed to achieve a vegetation management cycle within a specific jurisdiction. The model is based on KPCo's cost per line mile for achieving a cycle-based program and takes into account ongoing maintenance required on the system.

Q. Were additional estimates completed for KPCo's enhanced vegetation proposal?

A. Yes, Advanced Applicators, Inc. (AA), a third party consultant, was hired to complete a vegetation profile and project the correct volume of vegetation management needed to achieve a four-year cycle.

AA's vegetation profile, based on a statistical sample,[2] provides an indication of the difficulty associated with transitioning to a four-year vegetation cycle. According to their inventory, 34 percent of KPCo circuits are inaccessible with a standard bucket truck. In addition, projections made from AA's statistical sample indicate there are approximately 1.1 million trees to be trimmed, 760,000 trees to be removed and 17,100 acres of brush to be sprayed or cut from KPCo's existing ROW over the next five years. Of the trees to be trimmed, approximately 45 percent are

[2] The scope of the project included a random sample of distribution circuits located within the KPCo operating area. AA personnel conducted vegetation inventories at a total of 384 sample locations. Statistically this sample size provides a 95% confidence level with 5% margin of error.

less than three feet away from a conductor. The trees that need to be removed are either cycle-busting trees, hazard trees or large brush stems.

Q. Would KPCo be willing to provide an annual report to the Commission that would summarize the progress of the Enhanced Vegetation Initiative?

A. Yes, KPCo is absolutely willing to provide an annual summary on the progress of our Enhanced Vegetation Initiative. KPCo would like to work with Staff on the report format and level of detail required in order to produce the best result. An informative and meaningful report will benefit both Staff and the Company and provide transparency in regard to the Enhanced Vegetation Initiative.

Part 2: Enhanced Equipment Inspection and Mitigation Initiative

Q. Please briefly state the purpose of the Enhanced Equipment Inspection and Mitigation Initiative.

A. The purpose of this initiative is to improve the customer's overall service experience by reducing equipment-related outages to KPCo customers. This is proposed to be accomplished through a comprehensive equipment inspection and mitigation initiative, which will better enable KPCo to proactively identify and replace hardware and equipment that either are prone to failure or that have the increased likelihood to fail.

Q. Please identify the types of hardware and equipment that will be addressed.

A. Hardware on circuits includes poles, crossarms, insulators, conductors, connectors, splices, guy wires, guy anchors, ground wires, mounting brackets and other miscellaneous items. Equipment on circuits would include devices such as cutouts, arresters, and spacer cables.

Q. **Does the proposed Plan's Enhanced Equipment Inspection and Mitigation Initiative differ from current equipment inspections being performed?**

A. Yes. The current biennial inspection program basically provides for a visual assessment of the general condition of distribution facilities. This biennial visual inspection program can detect safety and reliability problems associated with equipment deterioration. However, it cannot determine the soundness of some poles which may be affected by ground-line and internal rot. These deteriorating poles may fall during severe weather conditions, or more easily break when a tree falls into the line or a car hits the pole. The integrity of all distribution equipment is vital to the reliability of the system and can be crucial to the safety of our workers and the general public.

The proposed Enhanced Equipment Inspection and Mitigation Initiative will continue the biennial visual inspection, but will add inspection and treatment of KPCo's pole plant on a recommended frequency of every 10 years after the first 15 years of life of the pole. The proposed work would also include focused cutout and lightning arrester replacements along with spacer cable replacement. Since porcelain cutout and lightning arrester equipment failures are on the rise, KPCo would use special technology to identify porcelain equipment that is beginning to break down in insulation before it is visible. The porcelain equipment would then be replaced before a failure occurred. Other proposed work would include the replacement of spacer cable. With most of KPCo's spacer cable over 30 years old, the insulation and spacers are beginning to fail and an enhanced effort needs to focus on replacing a majority of this type of cable.

In addition, as part of its Enhanced Equipment Inspection and Mitigation Initiative KPCo will use a variety of technologies, such as infrared inspections and electro-magnetic interference (EMI) detection devices, to identify distribution hardware and equipment in the beginning stages of failure. Specifically, a LEAD (Line Equipment Analysis Device) survey tool that AEP developed and patented will be used to detect EMI. Certain levels of EMI indicate an electrical arc, which in turn indicates a potential fault or problem with electrical equipment, such as cutouts and lightning arresters. EMI detection will permit failing cutouts and lightning arresters to be located and replaced before an outage occurs.

Another focus of a comprehensive maintenance program is the replacement of deteriorated spacer cable. Spacer cable is conductor that has a protective covering to prevent outages from incidental contact. Rather than being spread out on pole top crossarms, it is bundled together using insulated spacers to keep the conductors separated. The insulation covering permits temporary tree contact without necessarily operating the protective sectionalizing device. The Company currently is experiencing a high spacer cable failure rate and must use incremental funding to address this growing problem.

Q. **Please briefly describe the actions which will be taken based upon the results of the Enhanced Inspection and Mitigation Initiative.**

A. Following inspection of poles and equipment, the ensuing mitigation work will range from no action to full structure, hardware and equipment replacement. More specifically, the mitigation (repair and replacement) work would be categorized as follows:

- Full structure replacement to include the pole. The existing hardware and equipment would either be transferred to the replacement pole or replaced with new hardware and equipment, depending upon the condition of the existing units.
- Partial structure replacement such as a cross arm. The attached hardware and equipment would either be transferred to the replacement arm or replaced with new hardware and equipment, depending upon the condition of the existing units.
- Replacement of minor equipment such as arresters and cutouts as needed.

Q. **Please summarize the work units to be performed and associated costs for the Enhanced Equipment Inspection and Mitigation Initiative.**

A. Figure 11 represents the forecasted cost and units of work to be performed under the Enhanced Equipment Inspection and Mitigation Initiative.

Figure 11: Enhanced Equipment Inspection and Mitigation Initiative Summary and Associated Incremental Cost

Forecasted Incremental Units of Work	Year 1		Year 2		Year 3	
Miles to be Inspected	4,900		4,900		4,900	
Cutouts Replaced	806		806		806	
Arresters Replaced	500		500		500	
Poles Inspected	20,070		20,070		20,070	
Poles Replaced / Reinforced	112 / 413		112 / 413		112 / 413	
Miles of Spacer Cable Replaced	3		3		3	
($ Millions)						
Incremental Cost	O&M	Capital	O&M	Capital	O&M	Capital
	$0.827	$1.331	$0.856	$1.402	$0.886	$1.485
	$2.158		$2.256		$2.371	

Note: The data in Figure 11 is incremental to base amounts (TYE: 9/30/09), which totals $1.52M: $1.37M Capital and $0.15M O&M.

Q. Why is KPCo asking for additional funds for an Enhanced Equipment Inspection and Mitigation program?

A. As stated earlier in my testimony the objective of the pole inspection and maintenance program is to maintain and prolong the mechanical integrity of KPCo's wood poles. Poles in service for 15 years or longer are recommended, by AEPSC, to be inspected on an approximate 10-year cycle. As necessary, poles are treated, treated and reinforced, or replaced along with other equipment and hardware. This program is relatively expensive to maintain. To sustain the recommended 10-year cycle, KPCo needs to have additional funding built into base rates. The average annual cost for the Enhanced Equipment Inspection and Mitigation program is $856,000 in O&M and $1.41 million in Capital.

<u>Part 3: Distribution Workforce Planning Initiative</u>

Q. What is the next component of the Reliability and Service Enhancement Plan?

A. The need for KPCo to hire additional distribution employees to replace our aging workforce.

Q. Please describe the aging workforce in distribution operations.

A. KPCo's distribution workforce has an average age projected to be 50 by December 31, 2010. Additionally, 31 employees, or approximately 14 percent of the distribution workforce, will be age 60 or older. This is especially challenging for KPCo line maintenance organization because line personnel are employees with a unique, very specialized skill set who require a minimum of five years of training before one is considered a journeyman. (A journeyman is the term used for an experienced lineman). Eight of the 31 employees age 60 or older are journeyman line personnel.

Another position that requires extensive time to develop the necessary skills to perform effectively is the engineering professional. Even though an engineering professional has received an associate or bachelor degree, on-the-job experience cannot be taught in higher education institutions. For example, employees in these positions require several years of on-the-job training and safety instruction before becoming qualified to perform design techniques. Twelve of the 31 employees age 60 and older are engineering professionals.

The remaining employees age 60 or older are support personnel. Support personnel positions include meter readers, meter servicers and clerical associates. While these positions do not require the same length of time to train as a line mechanic or engineer, support personnel do however require roughly a year of on-the-job training before an individual has grasped the necessary concepts to safely perform the duties without direct supervision.

Q. **How many additional employees need hired?**

A. KPCo is proposing to hire 31 new distribution employees immediately to begin training as replacements for the 31 distribution employees who will be at least 60 years of age by the end of 2010. This course of action will reduce the risk of becoming understaffed at key positions. This will also allow time for proper on-the-job training under the existing personnel and reduce the loss of knowledge and experience that typically follows the retirement of a sizable portion of the workforce. This will also improve the safety of the employees and the public.

Q. What are the estimated costs of the additional employees?

A. KPCo estimates the cost to be approximately $2.7 million over the next three years (approximately $900,000 per year) and is shown below in Figure 12. This amount takes into account the hiring of new employees at entry level salaries net of the reduction in cost due to the retirements of existing employees at their present salaries.

Figure 12: Incremental KPCo Workforce Planning Summary and Associated Incremental Cost

Forecasted Units of Work	Year 1	Year 2	Year 3	Year 4	Year 5
Employees to be Hired	31	0	0	0	0
Employees to Retire	7	4	4	7	9
			($ Millions)		
Incremental Cost	**O&M**	**O&M**	**O&M**	**O&M**	**O&M**
	$0.956	$0.839	$0.655	$0.341	$0.679

Q. Why is KPCo asking for additional funds to replace employees?

A. Hiring new employees now will facilitate knowledge transfer and expedite the training process for those employees. It will therefore reduce the loss of knowledge and experience that will occur when the experienced employees retire and will permit proper safety training procedures to be embedded in the new employees to continue our excellent safety performance. To allow ample time for adequate training, new employees need to be hired three to five years before the experienced employees retire. This requires duplicate employees to remain on the payroll for extended periods and creates double costs of salaries without the opportunity of performing double amount of work. New employees do not perform at the same level as experienced employees and, therefore, are not able to complete as much work. The current rate structure does not permit KPCo to recover these expenses.

Q. What benefits would be realized with the additional employees on staff?

A. The primary benefit is a highly skilled workforce that can meet the growing demands of providing safe and reliable electric service for our customers and communities in which we serve. If additional employees are not hired before a retirement occurs, the skills will not be developed in a timely manner. If KPCo waits until retirements occur, the new hires will not have the proper time to learn from the experienced employees thus prolonging the lower productivity period associated with new employees.

Part 4: gridSMART^{sm} Initiative

Q. Would you please explain the term "gridSMART^{sm}?"

A. Begun in 2007, gridSMART^{sm} is a multi-year initiative by AEP and its operating companies that includes a suite of customer programs and advanced technology initiatives that will move KPCo into a new era of energy delivery and customer service. This will be accomplished by achieving energy efficiency and demand reduction, improving reliability, and positioning the distribution grid to accommodate and optimize new sources and storage options. The intitiative includes consumer-facing technologies and programs that will encourage energy efficiency and demand reduction. It also includes new grid management technologies that can improve reliability, achieve energy efficiency and demand reduction via actions that KPCo can implement, and provide the operating processes and systems that will be required to integrate future generation and storage device efficiencies.

The gridSMART^{sm} initiative includes integrating the information technology systems used for the programs and technologies to improve operating efficiencies and information available for customers. The technologies and integration utilize interoperability concepts consistent with the standards being developed by the National Institute of Science and Technology (NIST), as directed by the U.S. Department of Energy.

Q. Why is KPCo proposing the gridSMART^{sm} initiative?

A. Several converging factors make the timing right for these types of advances. These include the following:

- Much of KPCo's electricity delivery system is 20 to 30 years old or older. Existing equipment needs to be updated to accommodate new grid management technologies. Protection and control equipment with expanded technology capabilities will be required to support the growth in customer requirements and be consistent with the national vision of a "Smart Grid". Instead of replacing like-for-like equipment, gridSMART^{sm} enables the Company to install new technologies and advanced data and communications systems that better respond to increased service reliability expectations, deliver energy more efficiently, and accommodate distributed renewable energy sources.

- Customers' expectations concerning reliability are changing and adoption of sensitive electronics through all levels of society has increased the need and expectation for a reliable supply of high quality electric power. New grid management technologies associated with gridSMART^{sm} will help improve service reliability to better match customer expectations.

- Advanced communications and control technologies are becoming more affordable, more accessible, and easier to use than ever before.

These factors alone and in any combination are helping drive KPCo's response to what is a dramatically changing landscape of electricity distribution. As another significant benefit of gridSMART^{sm}, these initiatives will help minimize employees' exposure to injuries from work-related accidents and occasional confrontational customer interactions.

Q. Would you please describe each component of the gridSMART^{sm} initiative and related benefits being proposed by KPCo?

A. Yes. I will step through each component and discuss the related benefits.

Q. What is the first component of the gridSMART^{sm} initiative?

A. The first component of the proposed gridSMART^{sm} initiative is the addition of Supervisory Control And Data Acquisition (SCADA) installations in substations and on automated distribution line devices.

Q. What are the benefits of SCADA?

A. SCADA is a system operator tool used to remotely control and monitor transmission and distribution station and line equipment. SCADA improves reliability by providing system operators with remote control and monitoring capability over the transmission and distribution network. Utilization of this system shortens outage restoration times for customers and provides data and intelligence to sense abnormal or evolving system conditions.

Q. What incremental services will SCADA provide to KPCo?

A. SCADA will provide: 1) real time load information on station equipment such as transformers and breakers (this will allow action to be taken before serious loading problems can cause outages); 2) remote switching of station equipment which will reduce the restoration time required for many feeder breaker lockouts; 3) quick access to de-energize facilities for hazardous conditions found in the field - thus enhancing safety to the public and our workers; 4) the ability of distribution dispatchers to determine circuit outages even before customers call in, which will provide quicker response to these large scale outages; 5) the backbone infrastructure for future gridSMART^{sm} technologies.

KPCo's long-term reliability strategy includes the targeted installation of SCADA on remaining stations in the Company's service territory along with installation of SCADA for automated devices on distribution lines. This installation of SCADA for line devices will include necessary communication and computer equipment to begin separation of SCADA for distribution line equipment from the transmission SCADA System. This separation is necessary to allow integration of Distribution SCADA with distribution operation systems such as our Outage Management System (OMS). This will allow automatic outage case generation with information from the equipment without having to wait on customers to call in a trouble order. This provides for quicker outage analysis and response to outage cases. This integration is part of the gridSMART^{sm} interoperable technical architecture that includes sharing information between all distribution systems and would include using operational messages from Advanced Metering Infrastructure (AMI) meters if they are installed in the future. The separation will also allow higher levels of security to be maintained for the Transmission SCADA System.

Q. How many stations currently have SCADA installed and how many stations will SCADA need to be installed in?

A. Previously, KPCo has installed SCADA in 37 distribution stations but the remaining 55 distribution stations presently do not have SCADA.

Q. What is the second component of the gridSMART^{sm} initiative?

A. The second component of gridSMART^{sm} initiative is Distribution Automation (DA). DA provides real-time control and monitoring of selected electrical components within the distribution system. The electrical components to be controlled and monitored include station circuit breakers, line reclosers, and automated line switches. These electrical components will be connected via a two-way communication system to KPCo's dispatch operations center and will be equipped with sensors, which provide information on operational status and analog data such as voltage or current. When an interruption occurs, automated devices isolate the faulted zone and reconfigure the circuits by automatically opening (de-energizing) or closing (re-energizing), depending on the fault location. Customers not directly affected by the fault are immediately transferred to another source, if available, thereby restoring their service sooner.

Q. What are the benefits of DA?

A. Even with a high priority on investments aimed at avoiding outage events, it is unlikely that all outage events can be avoided. Distribution automation can, however, minimize the number of customers affected by the outage events that do occur.

Reviews of historical outage records indicate that approximately 10 percent of outage events involve main line devices (station breaker, main line recloser) yet 63 percent of the customer outage minutes are due to these main line outage events.

This illustrates the opportunity to improve customer outage experience by using distribution automation on main line devices to limit the number of customers impacted by an outage event to just those customers in the zone where the fault occurs.

Q. What is the third and final component of the KPCo gridSMART^{sm} initiative?

A. The third component of the gridSMART^{sm} initiative is Integrated Volt Var Control (IVVC). IVVC is a series of sensors and intelligent controllers which can monitor load flow characteristics and direct controls on capacitor and voltage-regulating equipment to optimize power factor (Var flow) and voltage levels. These controls utilize much of the same technology as DA and there are synergies when installing them together. KPCo plans to install the IVVC technology and demonstrate the benefits on selected stations and circuits. The IVVC will be installed in areas after the new DA systems are installed.

Q. What are the benefits of IVVC?

A. The two benefits of IVVC are 1) power factor optimization and 2) voltage optimization. Power factor optimization improves energy efficiency by reducing losses on the system and can improve reliability by relieving congestion on the transmission system. Voltage optimization can also allow a reduction of system voltage that still maintains minimum levels needed by customers but will cause a corresponding reduction in energy consumption. AEP is participating with the Electric Power Research Institute (EPRI) as well as conducting its own pilot installations to evaluate response rates of energy reduction and power factor improvement. Early results indicate a range of 0.5 percent to 1 percent of energy demand reduction for a 1 percent voltage reduction and power factors near unity are possible. KPCo anticipates that energy demand and consumption by customers on these circuits can reduce by approximately 2 percent with no impact on the level of service they receive and no action required to participate.

Q. Please summarize the work units to be performed and associated costs for the gridSMART℠ Initiative.

A. Figure 13 represents the forecasted cost and units of work to be performed under the gridSMART℠ Initiative.

Figure 13: gridSMART℠ Initiative Summary and Associated Incremental Cost

Forecasted Units of Work	**Year 1**		**Year 2**		**Year 3**	
Station SCADA (stations installed)	3		13		13	
Distribution SCADA (system installed)	1 Host System		-		-	
IVVC (circuits installed)	See Note Below		3		3	
DA (circuits installed)	3		3		4	
($ Millions)						
Incremental Cost	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**
	$0.154	$1.550	$0.235	$4.750	$0.105	$4.750
	$1.704		$4.985		$4.855	

Note: DA must be installed before KPCo can install IVVC

Q. Is Automated Metering Infrastructure (AMI) included in the KPCo gridSMART℠ proposal?

A. No. KPCo converted all residential meters to automated metering reading (AMR) technology in 2006, and thus the company is not currently proposing to convert to

AMI technology until 2012 or later. This will allow KPCo and its ratepayers to continue to reap the benefits of improved meter read attainment, accuracy and cost and safety reductions that are being provided by the AMR technology. In addition, industry projections predict that the cost of AMI technology will decline from current prices as more utilities adopt the technology, which would be a benefit to KPCo customers.

VI. CONCLUSION

Q. Mr. Phillips, please summarize your testimony.

A. My testimony has demonstrated the need for, benefits of, and cost (See EXHIBIT EGP-1, Summary of Reliability and Service Enhancement Adjustment) associated with implementing the Reliability and Service Enhancement Plan. The Plan includes an adjustment totaling $16.4 million in O&M and $9.2 million in Capital which includes: Enhanced Vegetation Initiative, Enhanced Equipment Inspection and Mitigation Initiative, Distribution Work Force Planning, and gridSMART Initiatives. The requested adjustment is both reasonable and necessary for ensuring that KPCo's customers receive the expected level of reliability and service to which they have grown accustomed.

Q. Does that conclude your direct testimony?

A. Yes, it does.

AFFIDAVIT

Everett G. Phillips, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Everett G. Phillips

Everett G. Phillips

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Everett G. Phillips this 17TH day of DECEMBER 2009.

Notary Public

My Commission Expires 4-5-2011

Reliability & Service Enhancement Adjustment

Amounts in $millions

	Year 1		Year 2		Year 3		Year 4		Year 5		Total	
	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital
Program												
Incremental Vegetation Management	$13.930	$1.840	$14.560	$2.040	$15.220	$2.240	$15.890	$2.460	$16.580	$2.690	$76.180	$11.270
Station SCADA	$0.0	$0.500	$0.0	$3.000	$0.0	$3.000	$0.0	$3.000	$0.0	$3.000	$0.000	$12.500
Distribution SCADA	$0.054	$0.300	$0.125	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.179	$0.300
IVVC Cannonsburg	$0.0	$0.0	$0.005	$1.000	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.005	$1.000
IVVC Louisa 12 kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.005	$0.5	$0.0	$0.0	$0.005	$0.500
IVVC Hitchens / Grayson	$0.0	$0.0	$0.0	$0.0	$0.005	$1.0	$0.0	$0.0	$0.0	$0.0	$0.010	$1.000
Distribution Automation	$0.100	$0.750	$0.100	$0.750	$0.100	$0.750	$0.0	$0.0	$0.0	$0.0	$0.300	$2.250
Enhanced Equipment Inspection and Mitigation Initiative	$0.827	$1.331	$0.856	$1.401	$0.886	$1.485	$0.917	$1.571	$0.949	$1.659	$4.435	$7.447
Distribution Work Force Planning	$0.956	$0.0	$0.839	$0.0	$0.655	$0.0	$0.341	$0.0	$0.679	$0.0	$3.470	$0.000
Total Loaded Costs	$15.87	$4.72	$16.4896	$8.19	$16.87	$8.48	$17.15	$7.53	$18.21	$7.35	$84.58	$36.27

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
DAVID M. ROUSH

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
DAVID M. ROUSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

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DIRECT TESTIMONY OF
DAVID M. ROUSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed as a Manager - Regulated Pricing and Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company.

Background

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT HISTORY.

A. I graduated from The Ohio State University (OSU) in 1989 with a Bachelor of Science degree in mathematics with a computer and information science minor. In 1999, I earned a Master of Business Administration degree from The University of Dayton. I have completed both the EEI Electric Rate Fundamentals and Advanced Courses. In 2003, I completed the AEP/OSU Strategic Leadership Program.

In 1989, I joined AEPSC as a Rate Assistant. Since that time I have progressed through various positions and was promoted to my current position of Manager – Regulated Pricing and Analysis in July 2003. My responsibilities include the oversight of the preparation of cost-of-service and rate design analyses for the AEP System operating companies, and the oversight of the preparation of special contracts and pricing for customers.

Q. **HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?**

A. Yes. I have submitted testimony before the Public Service Commission of Kentucky, Indiana Utility Regulatory Commission, Michigan Public Service Commission, the Public Utilities Commission of Ohio and the Public Service Commission of West Virginia regarding cost-of-service and rate design related issues.

Q. **FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of Kentucky Power Company, which I will refer to throughout my testimony either as KPCo, or as "the Company".

Purpose of Testimony

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

A. The purpose of my testimony is to support certain test year adjustments, address the allocation of the requested rate increase to the classes, support various changes in the proposed tariffs and the design of the rates for each tariff, and support portions of Section III of this filing with Witness Wagner.

List of Exhibits

Q. **WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?**

A. I am sponsoring the following exhibits:

Exhibit DMR-1	Customer Annualization Adjustment
Exhibit DMR-2	Third Party Revenue Adjustment
Exhibit DMR-3	Revenue Allocation
Exhibit DMR-4	Transmission Adjustment Tariff Rate Design

II. ADJUSTMENTS

Customer Migration Adjustment

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE CUSTOMER MIGRATION ADJUSTMENT?

A. Yes.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The purpose of the Customer Migration Adjustment is to determine the test year revenue that KPCo would have received if each customer were billed for the entire twelve months of the test year on the tariff under which the customer was taking service at the end of the test year. For example, a customer may have been billed under the MGS tariff for the first seven months of the test year and then billed under the LGS tariff for the remaining five months of the test year. During the test year, over 1,000 customers changed tariffs.

The Customer Migration Adjustment starts with the "per books revenue" as shown in Section III. "Per books revenues" means the revenues from customers as they were actually billed for each month of the test year. For purposes of the Customer Migration Adjustment, these customers would be re-billed for the entire test year under the tariff as applied at the end of the test year to determine the impact on test year revenues. This restatement of per books revenue was made for each customer who switched tariffs during the test year.

Q. WHAT IMPACT DOES THE CUSTOMER MIGRATION ADJUSTMENT HAVE ON TEST YEAR REVENUES?

A. The Customer Migration Adjustment results in an increase of test year revenues of $1,721,710 as shown in Section V, Workpaper S-4, page 24.

Customer Annualization Adjustment

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE CUSTOMER ANNUALIZATION ADJUSTMENT?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT.

A. The purpose of the Customer Annualization Adjustment is to restate test year revenues and expenses to reflect, on an annual basis, changes in load that occurred during the test year. For example, if the number of residential customers increased during the test year, per books residential kWh sales would have to be increased to reflect the impact of annualizing load growth that occurred within the test year. In addition to the revenue adjustment, test year operating expenses would also have to be increased to reflect the incremental costs associated with annualizing test year load growth.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The development of the Customer Annualization Adjustment is shown in Exhibit DMR-1 with additional detail shown in Section III of this filing. To ensure that the Customer Annualization Adjustment reflects only actual customer growth, the impact of customer migrations has been eliminated by starting with the data adjusted for the Customer Migration Adjustment.

Page 1 of Exhibit DMR-1 shows specific changes in large customer loads as identified by KPCo. Column (1) contains KPCo's current tariffs listed by delivery voltage level. Column (2) contains the total number of customers for the test year, while Column (3) contains the number of customers as of September 30, 2009. Columns (4) and (5) show metered kWh and revenues, respectively. Columns (6) through (9) show the specific adjustments for known changes in large customer usage, which produces a reduction in revenue of $302,353. Columns (10) through (13) are the sum of the data shown in Columns (2) through (5) and the adjustments shown in columns (6) through (9). This information is the starting point for the second part of the Customer Annualization Adjustment that is shown on page 2 of Exhibit DMR-1

Column (1) of page 2 of Exhibit DMR-1 contains KPCo's current tariffs listed by delivery voltage level. Column (2) contains the total number of customers for the test year, while Column (3) contains the average number of customers for the test year [Column (2) divided by 12]. Column (4) contains the number of customers as of September 30, 2009. Customer growth [Column (5)] is calculated as Column (4) less Column (3).

Customer growth [Column (5)] is then multiplied by test year average kWh per customer [Column (7)] to yield the kWh annualization adjustment [Column (8)]. The kWh annualization adjustment is in turn multiplied by the test year average revenue per kWh [Column (10)] to yield a revenue annualization adjustment of $2,827,387 as shown in Column (11).

In addition to the $2,525,034 increase ($2,827,387 - $302,353) in test year revenues resulting from the first two steps of the Customer Annualization Adjustment, test year operating expenses must also be increased to reflect the incremental cost KPCo would incur in generating 59,117,323 additional kWh (46,235,053 + 12,882,270). To calculate the incremental operating expenses, an operating ratio approach was used as shown on page 3 of Exhibit DMR-1.

The operating ratio is simply the ratio of operation and maintenance expense, less labor expense, to operating revenues. For KPCo, the operating ratio is 84.29%. Incremental operating expenses are then calculated by multiplying the incremental operating revenue ($2,525,034) by the operating ratio (84.29%) to yield $2,128,351. Incremental state and federal income taxes are also deducted to yield a net Customer Annualization Adjustment of $241,780 as shown in Section V, Workpaper S-4, page 45.

PJM Enhancement Revenue and Expenses Adjustment

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE PJM ENHANCEMENT REVENUE AND EXPENSES ADJUSTMENT?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT.

A. The purpose of the PJM Enhancement Revenue and Expenses Adjustment is to restate test year revenues and expenses to reflect known changes in the charges and credits that KPCo receives from PJM Interconnection, LLC (PJM) under Schedule 12, Transmission Enhancement Charges, of PJM's Tariff. Transmission Enhancement Charges are assessed by PJM based upon Federal Energy

Regulatory Commission (FERC) established revenue requirements for transmission investments made by transmission owners under PJM's Regional Transmission Planning process.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The charges under Schedule 12 are updated annually for many transmission owners, including AEP. This adjustment annualizes KPCo's expenses based upon changes in Schedule 12 charges that have occurred and will occur through January 2010 based upon known changes in rates. AEP's zonal responsibility for these charges is first divided between the portion that is the responsibility of AEP customers and that which is the responsibility of other entities in the AEP East transmission zone. Once that amount is determined, KPCo's portion is determined by applying KPCo's Member Load Ratio (MLR). As shown in Section V, Workpaper S-4, page 23, this calculation results in an annualized expense for KPCo of $1,422,308 which, when compared to a test year amount of $801,835, yields a total KPCo adjustment of $620,473.

This adjustment also annualizes KPCo's revenues based upon KPCo's share of AEP's revenue to be received for its Transmission Enhancements under rates that became effective July 1, 2009. The KPCo amount is determined by multiplying the total AEP amount by KPCo's MLR. As shown in Section V, Workpaper S-4, page 23, this calculation results in annualized revenues for KPCo of $222,913 which, when compared to a test year amount of $76,109, yields a total KPCo adjustment of $146,804.

Finally, the net amount of the adjustment ($467,038) is determined by applying a KPCo retail jurisdictional factor to the total KPCo amounts [0.986 x ($620,473 - $146,804)].

System Sales Margin Adjustment

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE SYSTEM SALES MARGIN ADJUSTMENT?

A. I am jointly responsible for the System Sales Margin Adjustment with Witnesses Myers and Wagner. Specifically, I am responsible for Columns (5) and (6) of the adjustment as shown in Section V, Workpaper S-4, page 26.

Q. PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT SHOWN IN COLUMNS (5) AND (6).

A. The purpose of the adjustment is to restate test year system sales margins to remove transmission and ancillary service revenues related to a sale to Carolina Power and Light (Progress Energy) that ends on December 31, 2009.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The calculation of test year system sales margins for KPCo included KPCo's share of transmission and ancillary service revenues from a contractual sale to Progress Energy that ends on December 31, 2009. As shown in Exhibit DMR-2, this adjustment annualizes KPCo's revenues based upon the level of transmission and ancillary service revenues at the end of the test year, adjusted for this sale which is ending. KPCo's amount is determined by applying KPCo's MLR to the adjusted total AEP amount at the end of the test year. As shown in Exhibit DMR-2 and Section V, Workpaper S-4, page 26, this calculation results in an annualized reduction in revenues for KPCo of $60,488 for ancillary services [Column (5)] and $392,189 for transmission service [Column (6)].

III. REVENUE ALLOCATION

Q. PLEASE EXPLAIN THE PRINCIPLES OR GUIDELINES THAT YOU FOLLOWED IN ALLOCATING THE PROPOSED REVENUE INCREASE AMONG THE TARIFF CLASSES.

A. One key objective of ratemaking is to design rates such that they reflect as nearly as possible the actual costs of serving the customer. To fully meet this objective would require that the rates of return for all tariff classes be equalized. The class cost-of-service study prepared by Witness High (Exhibit DEH-1) provides the information needed to make this evaluation.

As shown in Column (3) of page 1 of Exhibit DMR-3, the rate of return for the Residential (RS) class is below the total retail current rate of return of 1.11%. On the other hand, the rates of return for the remaining customer classes are above the total retail current rate of return. For example, the Commercial and Industrial Power – Time-of-Day (CIP-TOD) class has a 6.37% rate of return and the Municipal Waterworks (MW) class has a 6.55% rate of return.

In light of this variation in class rates of return, KPCo proposes to apply the rate increase of $123,626,013 in a manner that provides above average increases to those classes with rates of return below the total retail current rate of return and below average increases to those classes with rates of return in excess of the total retail current rate of return. The actual rate increase for each class was determined by use of an equal percentage subsidy reduction methodology.

Q. PLEASE EXPLAIN THE EQUAL PERCENTAGE SUBSIDY REDUCTION METHOD OF REVENUE ALLOCATION.

A. The first step in the process is to calculate the current subsidy for each class [Column (12) Exhibit DMR-3, page 2]. The current subsidy is defined as the difference between the equalized revenues (revenues if the class rate of return were set equal to the total retail current rate of return of 1.11%) and current class revenues. For example, the current subsidy for the residential class is $35,142,378, which means that residential rates would have to be increased by that amount to raise the class rate of return to 1.11%. Similarly, the current subsidy for the Quantity Power (QP) class is a negative $5,396,960, which means that the QP class rates would have to be reduced by that amount to lower the class rate of return to 1.11%.

The second step in the process is to calculate the revenues for each class at the total retail proposed rate of return [Column (11) Exhibit DMR-3, page 3]. This shows what each class would pay if all subsidies were eliminated and each class fully paid its actual costs at the proposed revenue level. As can be seen in Column (6), this would produce a significant increase in excess of 50% for the residential class.

The third step in the process is to exercise the principle of gradualism. In this context, it is not reasonable to eliminate all subsidies in this case. However, it is important to make progress toward eliminating interclass subsidies. The amount of such progress should be tempered by recognition of the rate impacts on the various tariff classes. As such, KPCo proposes to eliminate 10% of the current subsidies from all classes. To accomplish this, 90% of the current subsidy is added back (or deducted, as appropriate) to the class rate increases at proposed equalized rates of return as shown in Columns (12) and (13) of Exhibit DMR-3, page 3.

The final step is simply to recalculate the results using the increase determined in the third step. This is shown in Exhibit DMR-3, page 4.

IV. RATE DESIGN

Q. **PLEASE SUMMARIZE THE MAJOR RATE DESIGN MODIFICATIONS PROPOSED BY THE COMPANY.**

A. The significant rate design modifications proposed by the Company are as follows:

TARIFF	MODIFICATION
Experimental Residential Service Time-of-Day 2 (R.S.-T.O.D.2)	a) Introduce experimental time-of-day service to encourage customers to manage consumption during high cost winter and summer hours.
Experimental Small General Service Time-of-Day (S.G.S.-T.O.D.)	a) Introduce experimental time-of-day service to encourage customers to manage consumption during high cost winter and summer hours.
Large General Service Time-of-Day (L.G.S.-T.O.D.)	a) Introduce generally available time-of-day service for larger customers that do not qualify for Medium General Service Time-of-Day.
Quantity Power (Q.P.)	a) Introduce load factor blocked energy charge similar to Medium General Service to encourage load factor improvement and make a smoother transition from Large General Service.

Contract Service – Interruptible Power (C.S.-I.R.P.)	a) Reduce minimum interruptible load requirement from 5,000 kW to 1,000 kW.
	b) Make available to secondary and primary customers.
Outdoor Lighting (O.L.)	a) Introduce new lamps.
Street Lighting (S.L.)	a) Remove unused lamps and limit service on new metal or concrete poles to existing installations.
System Sales Clause (S.S.C.)	a) Revise language to reflect proposed margin sharing.
Net Merger Savings Credit (N.M.S.C.)	a) Discontinue Tariff.
Emergency Curtailable Service – Capacity and Energy Rider (E.C.S.-C. & E.)	a) Eliminate existing Emergency Curtailable Service Rider.
	b) Introduce new interruptible option available to smaller customers.
Energy Price Curtailable Service Rider (E.P.C.S.)	a) Rename P.C.S. Rider and modify provisions to make the rider more attractive for customers.
Alternate Feed Service Rider (A.F.S.)	a) Introduce new rider to provide for customer-requested redundant distribution service.
Transmission Adjustment (T.A.)	a) Introduce surcharge to track net transmission cost.

Other proposed tariff changes are discussed by Witness Wagner and identified in Section III of this filing.

Time-of-Day Service Offerings

Q. **PLEASE EXPLAIN THE COMPANY'S NEW TIME-OF-DAY SERVICE OFFERINGS.**

A. KPCo is proposing experimental Time-of-Day service tariffs for Residential and Small General Service customers and a Time-of-Day service for Large General Service customers. Each of these tariffs is an additional option for customers.

The experimental tariffs for Residential and Small General Service customers include three distinct energy charges for three time periods, winter on-peak, summer on-peak and all other hours. The winter on-peak period includes the weekday hours of 7 A.M. to 11 A.M. and 6 P.M to 10 P.M. during the months of November through March. The summer on-peak period includes the weekday hours of Noon to 6 P.M from May 15 through September 15. All other weekday hours, all weekend hours and the entire period from April 1 to May 14 and September 16 to October 31 are off-peak hours.

The time periods were selected based upon an evaluation of KPCo's load and also hourly market prices. The intent was to provide customers with a simple schedule (i.e. one that could be put on a refrigerator magnet) that would guide their energy usage decisions based upon the most important hours from an operations and cost perspective.

The tariffs were designed to be revenue neutral on an annual basis. In other words, KPCo customers, on average, would not pay any more or less by selecting the experimental tariff, except for \$3.55 per month for the additional cost of a more sophisticated meter to measure the time-of-day usage.

KPCo's proposed Large General Service Time-of-Day tariff is an extension of KPCo's existing Medium General Service Time-of-Day tariff to larger customers. The Large General Service Time-of-Day tariff is available to customers of up to 1,000 kW and includes a demand charge which primarily reflects the cost of local facilities that are necessary regardless of the time that a customer is using electricity. As with the experimental tariffs, the Large General Service Time-of-Day tariff was designed to be revenue neutral on an annual basis.

Changes in Quantity Power Tariff Q.P.

Q. PLEASE EXPLAIN THE CHANGES TO THE CURRENT TARIFF Q.P.

A. Tariff Q.P. applies to commercial and industrial customer with demand less than 7,500 kW and requires customer to contract for no less than 1,000 kW. Currently, Tariff Q.P. includes a monthly service charge, an on-peak demand charge, an off-peak excess demand charge, a reactive demand charge and an energy charge. The current structure of Tariff Q.P. is similar to Tariff C.I.P.-T.O.D. in that customer costs are predominantly collected in the monthly service charge, demand costs are predominantly collected in the demand charges and energy costs are predominantly collected in the energy charge, a D-E-C rate. Tariff C.I.P.-T.O.D. has historically been established as a full cost D-E-C rate, whereas Tariff Q.P. has historically been a nearly full cost D-E-C rate with some demand costs collected through the energy charge. This D-E-C rate structure makes the transition from Tariff Q.P. to Tariff C.I.P.-T.O.D. relatively easy for customers when their demands exceed 7,500 kW. However, the transition from Tariff L.G.S to Tariff Q.P. is much more difficult. Under Tariff L.G.S., a significant portion of demand costs are collected through the energy charge. This type of structure is not unusual. Smaller customers, particularly those with fluctuating usage, have not typically been billed on full cost D-E-C rates.

For this reason, KPCo is proposing to modify Tariff Q.P. to make the transitions between Tariff L.G.S., Tariff Q.P. and Tariff C.I.P.-T.O.D. easier for customers. This is achieved by introducing a load factor blocking of the Tariff Q.P. energy charge, similar to the one contained in KPCo's Tariff M.G.S. The load factor blocking was set at the existing crossover or breakeven point of 350 hours use per month (approximately 48% load factor) for Tariffs L.G.S. and Q.P. This is the point at which a customer's bill under Tariff L.G.S and Tariff Q.P. would be approximately equivalent. The second block energy charge was set at KPCo's full energy cost plus 15% of demand cost, which is comparable to the current energy charge in Tariff Q.P. The demand charge was set at a rate close to the proposed Tariff L.G.S. demand charge. Finally, the first block energy charge reflects full energy costs and residual demand costs not collected through the demand charge and second block energy charge.

Interruptible Service

Q. PLEASE EXPLAIN THE COMPANY'S CHANGES IN ITS INTERRUPTIBLE SERVICE OFFERINGS.

A. In this case, KPCo is proposing several new and modified interruptible service offerings. Given the meager interest in its current Emergency Curtailable Service Rider and Price Curtailable Service Rider offerings, KPCo proposes to eliminate the current offerings and replace them with new Emergency Curtailable Service -

Capacity & Energy and Energy Price Curtailable Service riders. These riders reflect significant modifications to the existing offerings with a focus on making them more attractive to customers while maintaining a benefit for all of KPCo's customers. In addition, KPCo is lowering the minimum interruptible contract requirement under Tariff C.S.-I.R.P. to 1,000 kW from its current 5,000 kW and eliminating the current limitation in availability to only subtransmission and transmission voltage customers.

System Sales Clause

Q. PLEASE EXPLAIN THE OPERATION OF THE COMPANY'S REVISED SYSTEM SALES CLAUSE TARIFF.

A. As discussed by Witnesses Myers and Wagner, the Company proposes modifying its System Sales Clause to implement a revised sharing mechanism. As in the past, a level of net revenues from system sales is included in base rates. The amount included in base rates is equivalent to 50% of the adjusted test year level ($7,645,182). On an annual basis, to the extent that KPCo's actual net revenues from system sales are less than 100% of the adjusted test year level ($15,290,363), KPCo customers will not be charged as they would have been under the current sharing mechanism. On an annual basis, to the extent that KPCo's actual net revenues from system sales are more than 100% of the adjusted test year level, KPCo customers will receive a credit equal to 50% of the actual net revenues in excess of 100% of the adjusted test year level.

Q. WILL THE REVISED SYSTEM SALES CLAUSE TARIFF OPERATE ON A MONTHLY OR ANNUAL BASIS?

A. The revised System Sales Clause Tariff will operate on a monthly basis. However, cumulative amounts during each annual period (year) must also be considered as part of the monthly calculation. Since, on an annual basis, customers will not be charged if actual net revenues from system sales fall below 100% of the adjusted test year level, KPCo must monitor its cumulative progress throughout the year toward meeting the annual goal.

KPCo considered two options regarding the operation of the tariff. The first option was to initially set the System Sales Adjustment Factor equivalent to zero (0) until such time as KPCo's cumulative net revenues from system sales for the year exceeded the 100% of the annual adjusted test year level. Under this option, the System Sales Adjustment Factor would typically be zero (0) for most months of the year, with the possibility of being a credit in the last few months of the year. The second option was to evaluate KPCo's net revenues from system sales on a monthly and cumulative monthly basis. The best way to explain the second option is through simplified examples.

Example 1: If in the first month of the year, KPCo's net revenues from system sales exceed the monthly test year amount by $100,000, the System Sales Adjustment Factor would be a credit to customers of $50,000. If in the next month of the year, KPCo's net revenues from system sales were $200,000 below the monthly test year amount, the System Sales Adjustment Factor would be a charge of $50,000 to customers, bringing the cumulative for the year to $0. In no event would the cumulative annual amount result in a charge to customers.

Example 2: If in the first month of the year, KPCo's net revenues from system sales were below the monthly test year amount by $100,000, the System Sales Adjustment Factor would be zero (0). If in the next month of the year, KPCo's net revenues from system sales were $200,000 above the monthly test year amount, the System Sales Adjustment Factor would be a credit of $50,000 to customers (50% of (-$100,000 + $200,000).

While both options have merit and ultimately produce the same result on an annual basis, the second option was selected as better matching the System Sales Adjustment Factor to the net revenues from system sales as they are realized. The specific tariff language detailing the calculation can be found in Section III of this filing.

Alternate Feed Service

Q. DOES KPCO PROPOSE A NEW TARIFF FOR ALTERNATE FEED SERVICE (AFS)?

A. Yes. Given the special nature of this service for customers that request a second distribution feed in addition to their basic service, KPCo proposes a special tariff to address the unique nature and costs of providing that service. For various reasons, AFS customers require a higher level of reliability than other customers. While KPCo wishes to meet the needs of its customers, it is important that such customers pay charges that reflect the full cost of providing such service. This prevents KPCo's other customers that do not benefit from bearing the additional costs for providing this premium service to customers that desire an alternate feed. Most importantly, the proposed Rider A.F.S. provides the proper price signal to customers concerning the cost of alternate feed service. This allows customers to make an economic choice whether an alternate feed or another alternative, such as an emergency generator, is the best way to meet their unique reliability needs.

KPCo's proposed Rider A.F.S includes two main provisions. First, the customer is responsible for all dedicated and/or local facilities required to provide the alternate feed. Second, the customer pays a monthly charge per kW for the capacity reserved on the Company's facilities for the alternate feed.

Transmission Adjustment Tariff

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED TRANSMISSION ADJUSTMENT TARIFF.

A. As discussed by Witness Bethel, the Company's transmission costs should be based upon the charges under PJM's Tariff (the Open Access Transmission Tariff or "OATT" and the Operating Agreement). The proposed Transmission Adjustment Tariff (Tariff T.A.) compares the charges under PJM's Tariff to the embedded cost of transmission as determined from KPCo's cost-of-service study and included in KPCo's proposed base rates.

As discussed by Witness Gregory, KPCo's books and records provide the information necessary to determine KPCo's charges under PJM's Tariff. As shown in Exhibit DMR-4, lines 11 through 18 itemize the total AEP East charges for transmission under the PJM Tariff for Network Integration Transmission

Service (NITS); associated Revenue Credits; Transmission Owner Scheduling, System Control and Dispatch Service; RTO start-up costs; Expansion Cost Recovery Charge; PJM Administrative Charges; and Transmission Enhancement Charges. Consistent with the PJM Enhancement Revenue and Expenses Adjustment, Transmission Enhancement Charges reflect charges at the January 2010 rate level. For each of these items, the current account in which the charge is recorded is identified in Column (4).

Once the total AEP East amount is determined on line 18, that amount is shown on line 1 and annualized on line 2. KPCo's amount (line 4) is determined by applying KPCo's MLR (line 3). Finally, the KPSC jurisdictional amount (line 6) is determined by applying a KPCo retail jurisdictional factor (line 5) to the total KPCo amount.

The KPSC jurisdictional amount (line 6) is then compared to the amount included in KPCo's proposed rates (line 7) to determine the Transmission Adjustment credit of $7,038,463 (line 8). This amount is the savings that Kentucky retail customers will realize by paying charges under the PJM Tariff instead of paying KPCo's embedded cost of transmission.

The Transmission Adjustment (line 8) is divided by total proposed revenues for all tariffs, excluding Tariffs O.L. and S.L. (line 9) to yield a Transmission Adjustment Factor of -1.12942% (line 10). Since Tariffs O.L. and S.L. do not have an embedded cost of transmission, the Transmission Adjustment Factor would not apply to those tariffs.

Q. PLEASE DESCRIBE THE OPERATION OF THE COMPANY'S PROPOSED TRANSMISSION ADJUSTMENT TARIFF.

A. The Transmission Adjustment Tariff will be updated annually. The most significant component of KPCo's charges under PJM's Tariff is NITS. The NITS rate for the AEP East zone is filed in late May to be effective on July 1 of each year. Given this, KPCo plans to file an update to the Transmission Adjustment Factor annually, on or about July 1, to be effective with the first billing cycle of August of each year. The annual filing will be based upon estimated costs and revenues for the ensuing August 1 to July 31 period.

In addition, as discussed by Witness Gregory, KPCo will be recording over/under recoveries based upon actual collections under the Transmission Adjustment Tariff and actual KPCo costs under PJM's Tariff, net of the transmission revenue requirement included in KPCo's base rates. KPCo will also file annually to reconcile any over/under recoveries through the Balancing Adjustment Factor in the Transmission Adjustment Tariff. Any refunds under PJM's Tariff for services rendered during the period would also be part of the annual reconciliation. This reconciliation will be performed at the end of each annual period and filed with the Commission on or about August 1 of each year to be effective for the eleven month period of September 1 to July 31.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT

David M. Roush, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

David M. Roush

David M. Roush

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by David M. Roush this 16th day of December 2009.

Ellen Q. McQuinn

Notary Public

My Commission Expires May 11th, 2011

KENTUCKY POWER COMPANY
DEVELOPMENT OF ANNUALIZATION ADJUSTMENT
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

					Specific Customer Adjustment				After Specific Customer Adjustment			
Tariff (1)	Year End Adjusted Number of Customers (2)	Sept 2009 Number of Customers (3)	Year End Adjusted Metered KWH (4)	Year End Migration Revenue (5)	Number of Customers (6)	Sept 2009 Number of Customers (7)	Metered KWH (8)	Revenue (9)	Year End Adjusted Number of Customers (10)=(2)+(6)	Sept 2009 Number of Customers (11)=(3)+(7)	Year End Adjusted Metered KWH (12)=(4)+(8)	Year End Migration Revenue (13)=(5)+(9)
RS Total	1,723,353	143,072	2,457,192,116	$197,351,853					1,723,353	143,072	2,457,192,116	$197,351,853
RSLMTOD Total	2,256	186	5,283,111	$359,588					2,256	186	5,283,111	$359,588
RS TOD Total	11	0	54,287	$4,146					11	0	54,287	$4,146
OL	792,515	66,390	43,521,208	$6,546,076					792,515	66,390	43,521,208	$6,546,076
SGS Metered Total	256,860	21,485	134,103,613	$14,068,805					256,860	21,485	134,103,613	$14,068,805
SGSLMTOD (225)	12	1	0	$186					12	1	0	$186
SGS NM Total	13,918	1,139	3,257,658	$438,216					13,918	1,139	3,257,658	$438,216
MGS RL (214)	894	75	1,782,674	$156,766					894	75	1,782,674	$156,766
MGS Sec Total	89,175	7,416	542,894,198	$48,703,993					89,175	7,416	542,894,198	$48,703,993
MGSLMTOD (223)	636	52	1,397,916	$101,530					636	52	1,397,916	$101,530
MGSTOD (229)	1,020	85	4,658,240	$370,990					1,020	85	4,658,240	$370,990
MGS Pri Total	934	80	22,411,331	$1,872,066	(10)	(2)	(1,219,500)	($98,867)	924	78	21,191,831	$1,773,199
MGS Sub (236)	188	15	8,534,499	$684,112	(2)	(1)	(87,500)	($6,626)	186	14	8,446,999	$677,486
LGS Sec Total	8,623	718	577,967,523	$45,381,739					8,623	718	577,967,523	$45,381,739
LGSLMTOD (251)	108	9	3,081,482	$231,572					108	9	3,081,482	$231,572
LGS Pri	1,127	91	106,217,850	$8,245,224	10	2	518,400	$29,668	1,137	93	106,736,250	$8,274,892
LGS Sub (248)	457	49	57,609,266	$3,919,669	(8)	1	1,347,850	$44,044	449	50	58,957,116	$3,963,713
QP Sec (356)	12	1	5,205,323	$310,222					12	1	5,205,323	$310,222
QP Pri	555	50	387,765,357	$24,977,993	(21)	(1)	(11,299,200)	($943,636)	534	49	376,466,157	$24,034,358
QP Sub (359)	428	36	475,444,199	$28,226,652	(33)	(3)	(38,055,500)	($2,478,776)	395	33	437,388,699	$25,747,876
QP Tran (360)	48	4	39,409,890	$2,388,032					48	4	39,409,890	$2,388,032
CIP Sub (371)	168	14	1,889,707,109	$101,632,803	0	0	41,058,000	$2,325,536	168	14	1,930,765,109	$103,958,339
CIP Tran (372)	48	4	365,065,276	$19,551,563	0	0	20,619,720	$826,303	48	4	385,684,996	$20,377,867
SL	145,403	12,071	8,517,949	$1,133,734					145,403	12,071	8,517,949	$1,133,734
MW (540)	240	20	7,821,424	$582,698					240	20	7,821,424	$582,698
Total	3,038,989	253,063	7,148,903,499	$507,240,229	(64)	(4)	12,882,270	($302,353)	3,038,925	253,059	7,161,785,769	$506,937,876

KENTUCKY POWER COMPANY
DEVELOPMENT OF ANNUALIZATION ADJUSTMENT
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

Tariff (1)	Year End Adjusted Number of Customers * (2)	Sept 2009 Annual Average Number of Customers (3)	Sept 2009 Number of Customers * (4)	Customer Growth (5)=(4)-(3)	Year End Adjusted Metered KWH * (6)	TME Sep 2009 Average KWH Per Customer (7)=(6)/(3)	KWH Annualization Adjustment (8)=(5)x(7)	Year End Migration Revenue * (9)	TME Sep 2009 Average Revenue Per KWH (10)=(9)/(6)	Revenue Annualization Adjustment ** (11)=(8)x(10)
RS Total	1,723,353	143,612.750	143,072	(540.750)	2,457,192,116	17,110	(9,252,233)	$197,351,853	$0.08032	($743,097)
RSLMTOD Total	2,256	188.000	186	(2.000)	5,283,111	28,102	(56,204)	$359,588	$0.06806	($3,827)
RS TOD Total	11	0.917	0	(0.917)	54,287	59,222	(54,287)	$4,146	$0.07637	($4,146)
OL	792,515	66,042.917	66,390	347.083	43,521,208	659	294,219	$6,546,076	$0.15041	$42,274
SGS Metered Total	256,860	21,405.000	21,485	80.000	134,103,613	6,265	501,200	$14,068,805	$0.10491	$52,584
SGSLMTOD (225)	12	1.000	1	0.000	0	0	0	$186	$0.00000	$0
SGS NM Total	13,918	1,159.833	1,139	(20.833)	3,257,658	2,809	(58,521)	$438,216	$0.13452	($7,873)
MGS RL (214)	894	74.500	75	0.500	1,782,674	23,929	11,965	$156,766	$0.08794	$1,045
MGS Sec Total	89,175	7,431.250	7,416	(15.250)	542,894,198	73,056	(1,114,104)	$48,703,993	$0.08971	($99,952)
MGSLMTOD (223)	636	53.000	52	(1.000)	1,397,916	26,376	(26,376)	$101,530	$0.07263	($1,916)
MGSTOD (229)	1,020	85.000	85	0.000	4,658,240	54,803	0	$370,990	$0.07964	$0
MGS Pri Total	924	77.000	78	1.000	21,191,831	275,219	275,219	$1,773,199	$0.08367	$23,032
MGS Sub (236)	186	15.500	14	(1.500)	8,446,999	544,968	(817,452)	$677,486	$0.08020	($65,595)
LGS Sec Total	8,623	718.583	718	(0.583)	577,967,523	804,315	(469,184)	$45,381,739	$0.07852	($36,840)
LGSLMTOD (251)	108	9.000	9	0.000	3,081,482	342,387	0	$231,572	$0.07515	$0
LGS Pri	1,137	94.750	93	(1.750)	106,736,250	1,126,504	(1,971,382)	$8,274,892	$0.07753	($152,829)
LGS Sub (248)	449	37.417	50	12.583	58,957,116	1,575,691	19,827,445	$3,963,713	$0.06723	$1,333,194
QP Sec (356)	12	1.000	1	0.000	5,205,323	5,205,323	0	$310,222	$0.05960	$0
QP Pri	534	44.500	49	4.500	376,466,157	8,459,914	38,069,613	$24,034,358	$0.06384	$2,430,437
QP Sub (359)	395	32.917	33	0.083	437,388,699	13,287,758	1,107,313	$25,747,876	$0.05887	$65,182
QP Tran (360)	48	4.000	4	0.000	39,409,890	9,852,473	0	$2,388,032	$0.06059	$0
CIP Sub (371)	168	14.000	14	0.000	1,930,765,109	137,911,794	0	$103,958,339	$0.05384	($0)
CIP Tran (372)	48	4.000	4	0.000	385,684,996	96,421,249	0	$20,377,867	$0.05284	$0
SL	145,403	12,116.917	12,071	(45.917)	8,517,949	703	(32,178)	$1,133,734	$0.13310	($4,286)
MW (540)	240	20.000	20	0.000	7,821,424	391,071	0	$582,698	$0.07450	$0
Total	3,038,925	253,243.750	253,059	(184.750)	7,161,785,769	28,280	46,235,053	$506,937,876		$2,827,387

* After Specific Customer Adjustment

** Values may not calculate due to rounding and calculation by lamp instead of customer for lighting.

KENTUCKY POWER COMPANY
DEVELOPMENT OF OPERATING RATIO
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

Line No.	Description	Amount	Source
1	Operating Revenues		
2	Sales of Electricity	$ 503,263,399	Sec. V, Sch.4, P.1, Col.(3), line 1
3	System Integration Agreement Adjustment	12,698,792	Sec.V, WP S-4, p.3, line 12
4	Capacity Charge Revenue Adjustment	(5,181,547)	Sec.V, WP S-4, p.4, line 16
5	Net Merger Savings Adjustment	5,218,680	Sec.V, WP S-4, p.5, line 15
6	Annualized Fuel Adjustment	(10,989,239)	Sec.V, WP S-4, p.6, line 8
7	Customer Migration Adjustment	1,721,710	Sec.V, WP S-4, p.24, line 10
8	Intercompany Revenue Billing Adjustment	508,868	Sec.V, WP S-4, p.43, line 3
9	Green Power Revenue Adjustment	(434)	Sec.V, WP S-4, p.44, line 3
10	Total	$ 507,240,229	Sum of Line 2 through Line 9
11	Operating Expenses		
12	Adjusted Operation & Maintenance	$ 453,834,609	Sec. V, Sch.4, P.1, Line 4. Col.(5) less Sec. V, WP S-4, P.45, Line 2, Col.(3)
13	Adjusted Labor Expense	26,300,126	OML Workpaper, plus Sec.V, WP S-4, p.32
14	Adjusted O&M Less Labor Expense	$ 427,534,483	Line 12 - Line 13
15	Operating Ratio		
16	Operating Ratio	84.29%	Line 14 / Line 10

Kentucky Power Company
Third Party Revenue Adjustment
Included in System Sales Margin Adjustment
Test Year Twelve Months Ended 9/30/2009

Line No. (1)	Description (2)	Ancillary Services Account 4470004 (3)	Sales for Resale Account 4470005 (4)
1	Total AEP September 2009 Amount	$70,094	$960,778
2	Less: CP&L September 2009 Amount	59,600	527,900
3	Adjusted Total AEP Amount (Ln 1 - Ln 2)	$10,494	$432,878
4	Annualized Total AEP Amount (Ln 3 x 12)	125,928	5,194,536
5	KPCo's Revised MLR	7.084%	7.084%
6	KPCo's Annualized Amount (Ln 4 x Ln 5)	$8,921	$367,981
7	KPCo 9/30/2009 Book Amount	69,409	760,170
8	Adjustment (Ln 6 - Ln 7)	($60,488)	($392,189)

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009

Current Class (1)	Current Revenue (2)	Current ROR % (3)	Current ROR Index (4)	Proposed Increase (5)	Proposed Increase % (6)	Proposed Revenue (7)	Proposed ROR % (8)	Proposed ROR Index (9)
RS	196,964,517	-2.88	(259)	68,841,686	34.95	265,806,203	4.93	58
SGS	14,551,918	6.37	574	3,254,247	22.36	17,806,165	13.25	156
MGS	51,640,578	5.64	508	10,897,697	21.10	62,538,275	12.60	148
LGS	58,995,442	4.05	365	12,580,744	21.32	71,576,186	11.16	131
QP	54,976,107	5.23	471	9,162,673	16.67	64,138,780	12.23	144
CIP-TOD	124,336,206	6.37	574	16,318,855	13.12	140,655,061	13.25	156
MW	582,698	6.55	590	105,484	18.10	688,182	13.41	157
OL	6,588,349	6.86	618	2,230,332	33.85	8,818,681	13.70	161
SL	1,129,448	14.45	1302	234,295	20.74	1,363,743	20.52	241
Total	509,765,263	1.11	100	123,626,013	24.25	633,391,276	8.52	100

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009

					Current Equalized Rate of Return						
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)=(11)-(2)
RS	196,964,517	535,133,286	(15,409,365)	-2.88	17.84	35,142,378	21,329,901	5,920,536	1.11	232,106,895	35,142,378
SGS	14,551,918	28,695,586	1,827,730	6.37	-17.10	(2,488,237)	(1,510,252)	317,478	1.11	12,063,681	(2,488,237)
MGS	51,640,578	95,086,690	5,362,597	5.64	-13.75	(7,101,971)	(4,310,589)	1,052,008	1.11	44,538,607	(7,101,971)
LGS	58,995,442	107,314,277	4,342,599	4.05	-8.81	(5,198,574)	(3,155,309)	1,187,290	1.11	53,796,868	(5,198,574)
QP	54,976,107	79,477,481	4,155,034	5.23	-9.82	(5,396,960)	(3,275,721)	879,313	1.11	49,579,147	(5,396,960)
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	-10.04	(12,480,301)	(7,575,002)	1,592,063	1.11	111,855,905	(12,480,301)
MW	582,698	932,532	61,044	6.55	-14.34	(83,576)	(50,727)	10,317	1.11	499,122	(83,576)
OL	6,588,349	19,808,487	1,359,190	6.86	-28.51	(1,878,281)	(1,140,035)	219,155	1.11	4,710,068	(1,878,281)
SL	1,129,448	2,340,686	338,163	14.45	-45.55	(514,478)	(312,266)	25,897	1.11	614,970	(514,478)
Total	509,765,263	1,012,689,101	11,204,057	1.11	0.00	0	0	11,204,057	1.11	509,765,263	0

Gross Rev Conversion Factor: 1.647564

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009

					Proposed Equalized Rate of Return						90% of	
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)	Proposed Increase (13)=(7)-(12)
RS	196,964,517	535,133,286	(15,409,365)	-2.88	51.01	100,469,826	60,980,834	45,571,469	8.52	297,434,343	31,628,140	68,841,686
SGS	14,551,918	28,695,586	1,827,730	6.37	6.97	1,014,834	615,960	2,443,690	8.52	15,566,752	(2,239,413)	3,254,247
MGS	51,640,578	95,086,690	5,362,597	5.64	8.73	4,505,923	2,734,900	8,097,497	8.52	56,146,501	(6,391,774)	10,897,697
LGS	58,995,442	107,314,277	4,342,599	4.05	13.39	7,902,027	4,796,188	9,138,787	8.52	66,897,469	(4,678,717)	12,580,744
QP	54,976,107	79,477,481	4,155,034	5.23	7.83	4,305,409	2,613,197	6,768,231	8.52	59,281,516	(4,857,264)	9,162,673
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	4.09	5,086,584	3,087,336	12,254,401	8.52	129,422,790	(11,232,271)	16,318,855
MW	582,698	932,532	61,044	6.55	5.19	30,266	18,370	79,414	8.52	612,964	(75,218)	105,484
OL	6,588,349	19,808,487	1,359,190	6.86	8.19	539,879	327,683	1,686,873	8.52	7,128,228	(1,690,453)	2,230,332
SL	1,129,448	2,340,686	338,163	14.45	-20.25	(228,735)	(138,832)	199,331	8.52	900,713	(463,030)	234,295
Total	509,765,263	1,012,689,101	11,204,057	1.11	24.25	123,626,013	75,035,636	86,239,693	8.52	633,391,276	0	123,626,013
								86,239,693				

Gross Rev Conversion Factor: 1.647564

Exhibit DMR-3

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009

					Proposed Revenue Allocation					
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	Proposed Revenue (10)	ROR % (11)
RS	196,964,517	535,133,286	(15,409,365)	-2.88	34.95	68,841,686	41,783,922	26,374,557	265,806,203	4.93
SGS	14,551,918	28,695,586	1,827,730	6.37	22.36	3,254,247	1,975,187	3,802,917	17,806,165	13.25
MGS	51,640,578	95,086,690	5,362,597	5.64	21.10	10,897,697	6,614,430	11,977,027	62,538,275	12.60
LGS	58,995,442	107,314,277	4,342,599	4.05	21.32	12,580,744	7,635,967	11,978,566	71,576,186	11.16
QP	54,976,107	79,477,481	4,155,034	5.23	16.67	9,162,673	5,561,346	9,716,380	64,138,780	12.23
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	13.12	16,318,855	9,904,838	19,071,903	140,655,061	13.25
MW	582,698	932,532	61,044	6.55	18.10	105,484	64,024	125,068	688,182	13.41
OL	6,588,349	19,808,487	1,359,190	6.86	33.85	2,230,332	1,353,715	2,712,905	8,818,681	13.70
SL	1,129,448	2,340,686	338,163	14.45	20.74	234,295	142,207	480,370	1,363,743	20.52
Total	509,765,263	1,012,689,101	11,204,057	1.11	24.25	123,626,013	75,035,636	86,239,693	633,391,276	8.52

Gross Rev Conversion Factor: 1.647564

Kentucky Power Company
Transmission Adjustment Tariff
Rate Design
Test Year Twelve Months Ended 9/30/2009

Line No. (1)	Description (2)	Amount (3)
1	Total AEP September 2009 Amount (Ln 18)	$50,676,451
2	Annualized Total AEP Amount (Ln 1 x 12)	608,117,412
3	KPCo's Revised MLR	7.084%
4	KPCo's Annualized Amount (Ln 2 x Ln 3)	$43,079,037
5	Allocation Factor - GP-Trans	0.986
6	KPSC Jurisdictional Amount (Ln 4 x Ln 7)	$42,475,930
7	Transmission Cost in Proposed Rates	49,514,393
8	Transmission Adjustment (Ln 6 - Ln 7)	($7,038,463)
9	Proposed Revenues excluding OL and SL	$623,195,180
10	Transmission Adjustment Factor	-1.12942%

Line No. (1)	Description (2)	Total AEP September 2009 Amount (3)		Current Accounts (4)
11	NITS Charges	$45,744,372		4561035
12	Revenue Credits	(770,106)		4561005
13	RTO start-up costs	176,007		4561002
14	Transmission Owner Scheduling, System Control and Dispatch Service	656,702		4561036
15	Expansion Cost Recovery Charge	116,108		4561003
16	PJM Administrative Charges	3,080,222		5614001, 5614007, 5618001, 5757001
17	Transmission Enhancement Charges	1,673,146	*	5650012
18	Total (Sum Ln 11 through Ln 17)	$50,676,451		

* Workpaper S-4, Page 23: $1,845,721 x 90.65% = $1,673,146

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY CASE NO. 2009-00459

DIRECT TESTIMONY
OF
ERROL K. WAGNER

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
ERROL K. WAGNER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

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DIRECT TESTIMONY OF
ERROL K. WAGNER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A: My name is Errol K. Wagner. My position is Director of Regulatory Services, Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I received a Bachelor of Science degree with a major in accounting from Elizabethtown College, Elizabethtown, Pennsylvania in December 1973. I am a Certified Public Accountant. I worked for two certified public accounting firms prior to joining the Pennsylvania Public Utility Commission Staff in 1976. In 1982, I joined the American Electric Power Service Corporation ("AEPSC") as a Rate Case Coordinator. In 1986, I transferred from AEPSC to Kentucky as the Assistant Rates, Tariffs and Special Contracts Director. In July 1987, I assumed my current position.

Q: WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF REGULATORY SERVICES?

A: I supervise and direct the Regulatory Services of the Company, which has the responsibility for rate and regulatory matters affecting Kentucky Power. This includes the preparation of and coordination of the Company's exhibits and testimony in rate cases and any other formal filings before state and federal regulatory bodies. Another responsibility is assuring the proper application of the Company's rates in all classifications of business.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I have testified before this Commission in numerous regulatory proceedings involving the adjustment in electric base rates, the fuel adjustment clause, the environmental surcharge tariff, approval of certificates of public convenience and necessity and other regulatory matters. I also filed testimony in KPCo's last general adjustment in electric base rates in Case No. 2005-00341.

III. PURPOSE OF TESTIMONY

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

A: The purpose of my testimony is to support the revenue requirement being proposed by the Company; to support certain known and measurable adjustments to test year capitalization and test year revenues and operating expenses; to support the Kentucky retail jurisdictional factors or amounts; and to support certain tariff changes. In order to fully understand the development of the Company's proposed revenue requirement, which includes certain revenue and expense adjustments, I will give a description of three pertinent Federal Energy Regulatory Commission (FERC) approved agreements to which the Company is a party. These agreements are the AEP Interconnection Agreement, the AEP Transmission Agreement and the AEP Interim Allowance Agreement.

Q: **ARE YOU SPONSORING ANY SCHEDULES INCLUDED IN THE COMPANY'S FILING OR EXHIBITS TO YOUR TESTIMONY?**

A: Yes. I identify the schedules and exhibits that I am sponsoring throughout my testimony.

Q: **WERE THESE SCHEDULES AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A: Yes.

IV. RELEVANT FERC APPROVED AGREEMENTS

The AEP Interconnection Agreement

Q: **AS BACKGROUND, PLEASE BRIEFLY DESCRIBE THE AEP INTERCONNECTION AGREEMENT AND THE CALCULATION OF THE MEMBER LOAD RATIO (MLR).**

A: KPCo, Appalachian Power Company (APCo), Columbus Southern Power Company (CSP), Indiana Michigan Power Company (I&M) and Ohio Power Company (OPCo) are the five AEP System operating companies (hereafter "AEP System-East Zone") that are members of the AEP Pool established pursuant to the FERC approved AEP Interconnection Agreement. Although each operating company owns specific generating facilities, the AEP System is designed, built and operated on an integrated system basis. The AEP Interconnection Agreement defines the rights and obligations of the five operating companies (each called a "member") and sets out the methodology for allocating the benefits and cost of generation among the members. Significant aspects of the AEP Interconnection Agreement are as follows:

- Requires each member to provide adequate generating facilities (or resources) to meet its firm load requirement.
- Allocates the AEP Pool capacity on the basis of each member's highest non-coincident peak in the preceding twelve months (i.e., Member Load Ratio, or MLR). The MLR is the ratio of a member's highest non-coincident peak in relationship to the total of all members highest non-coincident peak.
- Provides a Capacity Settlement that equalizes responsibility for installed capacity. The capacity settlement equalizes reserve margins by assigning responsibility to each member for its MLR share of system capacity. To the extent that a member's capacity is less than its system responsibility, such deficit company is required to make up its shortfall by paying a capacity charge to the surplus companies, based on the embedded cost of capacity of the surplus companies.
- Each member must make their transmission facilities available to all members for the delivery and receipt of power.

Q: PLEASE DESCRIBE THE CALCULATIONS OF THE CAPACITY SETTLEMENT.

A: Exhibit EKW-1 demonstrates the monthly capacity equalization settlement calculation under the Interconnection Agreement. First, the total members' primary capacity installed is multiplied by each member's MLR to arrive at the member's primary capacity reservation (See Exhibit EKW-1 Columns 1, 2 and 3). This primary capacity reservation is then compared with the installed capacity contributed by each member (See Exhibit EKW-1, Columns 1 and 3). If a member's primary capacity reservation exceeds its installed capacity contribution, the difference is a capacity deficit that is met by those member(s) having surplus capacity. If a member's installed capacity contribution exceeds its reservation, the difference is a capacity surplus, which is supplied to the AEP System-East Zone. The total capacity surplus in any given month for surplus members always equals the total primary capacity reservation deficiency for the deficit members (i.e., producing a zero surplus/deficit balance for the AEP System-East Zone) (See Exhibit EKW-1, Column 4).

Q: HOW ARE THE SURPLUS MEMBERS REIMBURSED BY THE DEFICIT MEMBERS?

A: Surplus members are reimbursed through monthly capacity settlement charge payments made by deficit companies. To calculate these payments, AEP first calculates the AEP Pool capacity rate. Exhibit EKW-2 demonstrates the AEP Pool capacity rate calculations under the Interconnection Agreement. The AEP Pool capacity rate is made up of two components: the primary capacity investment rate and the fixed operating rate. The primary capacity investment rate reflects the surplus member's average embedded cost of capacity multiplied by the FERC-approved carrying charge rate. The fixed operating rate reflects the surplus member's steam plant operations expense and one-half of the steam plant maintenance expense divided by its installed capacity. An example of the capacity rate calculations for the surplus members (I&M and OPCo) is provided in Exhibit

EKW-2. Also provided on Exhibit EKW-2 is the weighted average rate, which is paid by the deficit members.

Q: HOW ARE THE DEFICIT MEMBERS' CAPACITY SETTLEMENT CHARGES CALCULATED?

A: A deficit company, such as KPCo, computes its capacity settlement charge by multiplying its capacity deficit by the Pool's weighted average capacity rate of the surplus companies (See Exhibit EKW-1, Columns 5, 6 and 7).

Q: WOULD YOU PLEASE WALK US THROUGH THE AEP SYSTEM-EAST ZONE CAPACITY SETTLEMENT CHARGE CALCULATIONS FOR KPCO?

A: Yes. KPCo's monthly MLR is calculated by dividing KPCo's highest non-coincident peak in the preceding twelve months by the total of all of the members' highest non-coincident peaks (1,674 MW / 23,680 MW) resulting in an MLR of 0.07069 (See Exhibit EKW-1, Line 2, Column 2). KPCo's primary capacity reservation is determined by multiplying its MLR for the month (0.07069) by the members' total generating capacity (26,220,000 kW). This equals a primary capacity reservation for KPCo of 1,853,500 kW (See Exhibit EKW-1, Line 2, Column 3). KPCo's installed generating capacity is equal to 1,453,000 kW (1,060,000 kW at Big Sandy Generating Plant and 393,000 kW at Rockport Generating Plant). By comparing KPCo's reservation capacity under the AEP Pool Agreement with its installed primary capacity, KPCo has a capacity deficit of 400,500 kW (1,853,500 - 1,453,000 kW) for the month (See Exhibit EKW-1, Line 2, Column 4). Multiplying the weighted average capacity rate of the surplus companies (I&M and OPCo) of $11.98/kW times KPCo's capacity deficit of 400,500 kW produces a capacity settlement charge for KPCo of $4,798,246 for the month (See Exhibit EKW-1, Line 8, Column 7).

Q: WHEN DO THE COSTS ASSOCIATED WITH NEW GENERATING FACILITIES APPEAR IN THE MONTHLY CAPACITY RATE?

A: The Steam Plant Operation Expense and one half of Maintenance Expense for new facilities will appear in the fixed operating rate for the month in which the expense is incurred by the surplus companies. The primary capacity investment rate reflects the level of Steam Production Plant in-service as of December 31st of the prior year.

Q: IN THE TEST YEAR WHAT WERE THE TOTAL CAPACITY CHARGES PAID BY KPCO THROUGH THE INTERCONNECTION AGREEMENT?

A: Based on a September 30, 2009 test year, the annual capacity charge paid by KPCo under the Interconnection Agreement was $57,077,395 (See Section V, Workpaper S-4, Page 9, Column 4).

AEP Transmission Agreement

Q: AS BACKGROUND, PLEASE BRIEFLY DESCRIBE THE AEP TRANSMISSION AGREEMENT.

A: The AEP Transmission Agreement is a FERC approved agreement among the AEP System-East Zone Companies. The Transmission Agreement provides for an equitable method of sharing transmission costs incurred by the members in connection with the ownership of their respective portion of the AEP high voltage transmission system. Also, this agreement promotes the continued development of a reliable and economic transmission system by members.

Q: COULD YOU GIVE A BRIEF DESCRIPTION OF TRANSMISSION FACILITIES INCLUDED IN THE TRANSMISSION AGREEMENT?

A: Yes. Under the Interconnection Agreement, each member must make its transmission facilities available to all members for the delivery and receipt of power. The transmission facilities commonly referred to as Bulk Power Transmission facilities, include the following:

- All transmission lines operating at a nominal voltage of 138-kV or higher,
- All facilities such as transformers, buses, switchgear and associated facilities located at transmission substations operating at a nominal voltage of 345-kV and above, including Extra High Voltage (EHV)/138-kV substations, and
- Other transmission facilities that are designated by the Transmission Committee as having been installed for the mutual benefit of all members.

Q: WHAT ARE THE OBLIGATIONS OF THE MEMBERS UNDER THE TRANSMISSION AGREEMENT?

A: Each member is required to maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair to permit the System to operate in a reliable and satisfactory manner.

Q. IS THERE A COST-SHARING MECHANISM UNDER THE TRANSMISSION EQUALIZATION AGREEMENT?

A. Yes, much like the Interconnection Agreement, the Transmission Agreement provides for payments by transmission-deficit members to transmission-surplus members. Each member's surplus or deficit is calculated by multiplying that member's MLR by the AEP System-East Zone's total investment in Bulk Transmission facilities investment. That result is compared to the amount of Bulk Transmission investment the member has recorded on its own books and records as of December 31 of the previous year. If the difference is positive the member is a surplus member; if the difference is negative the member is a deficit member. Currently, KPCo is a surplus member and receives a payment from the deficit members. During the test year KPCo received $7,463,087 (See Section V, Workpaper S-4, page 7, Column 4) in payments under the Transmission Agreement. These receipts were recorded as a credit to KPCo's O&M expense thus reducing the cost-of-service to the customers.

Q. HAS THERE BEEN CHANGES PROPOSED TO THE TRANSMISSION AGREEMENT?

A. Yes. AEPSC on behalf of the members proposed to modify the transmission agreement in FERC Docket ER09-1279. These changes and the benefits to KPCo are discussed in the testimony of Witness Bethel on pages 6 through 8.

Interim Allowance Agreement

Q: PLEASE BRIEFLY DESCRIBE THE AEP INTERIM ALLOWANCE AGREEMENT.

A: KPCo is a member of the FERC-approved AEP Interim Allowance Agreement (IAA). In developing the IAA, the AEP System-East Zone companies worked in close cooperation with the AEP Regional Coordinating Committee, a committee consisting of representatives and/or staff from each of the seven state regulatory commissions (including Kentucky) that oversee the utility operations of the AEP System-East Zone companies. The AEP System-East Zone is designed, built and operated as one electric system. As a member of the IAA, KPCo shares in the costs and benefits associated with SO_2 emission allowances for the AEP System-East Zone.

The IAA was filed with the FERC in September 1994. The IAA provides for and governs the terms of five basic types of SO_2 allowance transactions among the AEP companies: (1) an annual reallocation of allowances initially allocated by the U.S. Environmental Protection Agency (EPA) to Ohio Power's Gavin Plant; (2) transfers of allowances associated with primary and economy energy transactions among the members; (3) a monthly cash settlement for allowances consumed in connection with power sales to foreign (i.e., non-affiliated) companies; (4) transfers of allowances for current period compliance; and (5) transfers of allowances for future period compliance. Following approval by FERC, Modification No. 1 to the IAA made the following changes to the agreement effective September 1996: (1) each member was required to own its MLR share of the AEP System-East Zone allowance bank at the end of each year; (2) each member was required to pay for and receive its MLR share of any allowances purchased from third parties, including any allowances purchased at EPA auctions held pursuant to Section 416 of the 1990 Clean Air Act Amendments, 42 U.S.C. §7651o; (3) each member was required to contribute its MLR share of allowances toward any sale to third parties and would receive its MLR share of the proceeds from any such sales; (4) each member shared in the net proceeds and costs, and accrued carrying charges, on such proceeds and costs associated with allowance transactions with non-affiliates which occurred prior to the effective date of Modification No. 1; and (5) each member retained the proceeds associated with the sale of its withheld allowances at EPA auctions.

V. PROPOSED INCREASE IN ANNUAL REVENUES

Q: PLEASE DESCRIBE THE DEVELOPMENT OF THE REVENUE REQUIREMENT BEING PROPOSED BY THE COMPANY.

A: The Company is proposing an annual revenue requirement of $645,423,318. This represents an increase of $123,626,013 over the Test Year ended September 30, 2009 adjusted revenues of $521,797,305, or an increase of approximately 24.25%. The development of these amounts is shown on Schedule 1 of Section V of the Company's filing. Schedule 2 is a summary supported by various other schedules and workpapers. As shown on Schedule 2, Kentucky Power's adjusted September 30, 2009 Capitalization of $994,690,811 was multiplied by the recommended overall rate of return of 8.67% to determine the Required Net Electric Operating Income of $86,239,693. The Company's test year adjusted Net Electric Operating Income of $11,204,057 was then subtracted from the Required Net Electric Operating Income to determine the required increase of $75,035,636 to the Company's test year Net Electric Operating Income. This amount was multiplied by the Gross Revenue Conversion Factor (GRCF) of 1.6476 to determine the proposed annual increase to retail revenues of $123,626,013.

Q: **WHY IS THE GRCF USED IN DETERMINING THE REQUIRED REVENUE INCREASE?**

A: The Required Net Electric Operating Income is an amount which is net of uncollectible accounts, the Kentucky Public Service Commission assessment fee, and State and Federal income taxes. To calculate the required annual revenue requirement, the Net Electric Operating Income must be grossed up to account for the effects of uncollectible accounts, Kentucky Public Service Commission assessment fee, State and Federal income taxes.

Q: **HOW WAS THE GRCF OF 1.6476 DETERMINED?**

A: The same methodology was used in this case in calculating the GRCF of 1.6476 as was utilized in the Company's prior cases with one exception. The West Virginia state income taxes that KPCo is obligated to pay were incorporated into the GRCF in this case (See Section V, Workpaper S-2, page 2 of 3).

Q: **PLEASE EXPLAIN WHY KPCo IS OBLIGATED TO PAY WEST VIRGINIA STATE INCOME TAX.**

A: KPCo employees who work out of the Williamson, West Virginia Service Building provide electric service to the KPCo retail customers located in the South Williamson, Kentucky service area. The presence of these workers in West Virginia creates a taxable presence with the state, thereby obligating KPCo to pay West Virginia state income tax on its West Virginia apportioned taxable income.

Q: **WHY DO KPCo EMPLOYEES WORK OUT OF THE WILLIAMSON, WEST VIRGINIA SERVICE BUILDING RATHER THAN WORKING OUT OF ONE OF KPCo's SERVICE BUILDINGS LOCATED IN KENTUCKY?**

A: The Williamson, West Virginia Service Building is less than one mile from South Williamson, Kentucky. The closest KPCo service building is located in Pikeville, Kentucky, which is over 20 miles from South Williamson. Assigning KPCo employees to the Williamson, West Virginia Service Building reduces travel time to the different job sites in the South Williamson, Kentucky area. That, in turn, enables the Company to serve the customers more efficiently and promptly, thereby improving productivity and service levels.

Q: **HAS THE COMPANY REFLECTED THE ANNUAL EFFECT OF THE SECTION 199 DEDUCTION UNDER THE INTERNAL REVENUE CODE IN THE CALCULATION OF THE FEDERAL INCOME TAX OBLIGATION?**

A: No. The Company did not reflect a Section 199 deduction in the calculation of the State and Federal income tax liability because KPCo did not have any taxable income in 2008. Therefore the Company was not eligible to take advantage of the Section 199 deduction. This approach is consistent with the positions of both the Federal Energy Regulatory Commission's June 2, 2005 guidance letter and the Financial Accounting Standards Board (FASB) Staff Position No. FAS 109-1 titled Application of FASB Statement No. 109, *Accounting for Income Taxes,* which was issued on December 21, 2004.

Q: WHEN DID KPCo LAST CLAIM A SECTION 199 DEDUCTION IN CALCULATING ITS FEDERAL TAX LIABILITY?

A: KPCo last claimed a Section 199 deduction on its 2006 federal tax return.

Q: DOES KPCo EXPECT TO CLAIM A SECTION 199 DEDUCTION ON ITS 2009 OR ITS 2010 TAX RETURN?

A: No for both years. KPCo is not expected to have positive qualified manufacturing income in 2009 or 2010; the result being that KPCo will not receive a Section 199 deduction in either year

Q: SINCE THERE IS NO SECTION 199 DEDUCTION REFLECTED IN THE BASE RATE CALCULATIONS, WOULD THERE BE ANY REQUIRED CHANGES TO THE ENVIRONMENTAL SURCHARGE MONTHLY CALCULATIONS?

A: Yes. The monthly Environmental Surcharge calculations should be changed to eliminate the effect of the Section 199 deduction from the Gross Revenue Conversion Factor calculation because KPCo is not eligible to take advantage of the Section 199 deduction provision of the Internal Tax Code.

Q. WHAT WILL BE THE EFFECT ON THE ENVIRONMENTAL SURCHARGE MONTHLY CALCULATIONS?

A. The effect on the Environmental Surcharge monthly calculations would be to exclude the Section 199 Deductions from the GRCF calculations and it would synchronize the GRCF used in the Environmental Surcharge calculations with the GRCF used for rate making purposes.

Q: EXPLAIN HOW THE WEIGHTED AVERAGE COST OF CAPITAL OF 8.67% WAS CALCULATED.

A: Please refer to Section V, Workpaper S-2, page 1 of 3. The Company started with the Reapportioned Kentucky Jurisdiction capital as calculated on Section V, Schedule 3 Column 11 for each category of capital. The Company then divided the dollar amount of each category of capital by the Company's total dollar amount of capital to calculate the percentage of the Company's total capital each category constitutes. This result is shown in Column 4.

Q. WHAT RATES WERE USED IN CALCULATING THE COMPANY'S WEIGHTED COST OF CAPITAL?

A. The cost of long term debt used in the calculation was the Company's actual cost experienced during the test period. The cost of the short term debt used in the calculation was the Company's actual short term interest expense for the twelve months ended September 30, 2009 divided by the actual average borrowings outstanding during the same time period (See Section V, Workpaper S-3, pages 1 and 2 of 3). The cost of accounts receivable financing used in the calculation was calculated by using a 13 month average cost experienced by the Company during the test year. The cost of common equity used in the calculation is the same amount recommended by Witness Avera.

Q. WHAT WERE THE FINAL STEPS IN CALCULATING THE COMPANY'S WEIGHTED COST OF CAPITAL?

A. The percentage of each category of capital represented by the Company's total capital (Column 4) was multiplied by the "Annual Cost Percentage Rate" (Column

5) for each category of capital to arrive at each category's weighted cost of capital. The weighted average cost of capital for each category was added to arrive at the Company's total weighted average cost of capital of 8.67%.

Q: **PLEASE BRIEFLY DESCRIBE THE OTHER SCHEDULES INCLUDED IN SECTION V.**

A: Section V consists of 19 schedules and supporting workpapers.

Schedule 1 summarizes the components of Net Electric Operating Income for the twelve months ended September 30, 2009, as adjusted, under present rates (Column 3); and the effects of the proposed rate increase on those components (Column 4). Also shown are the components of Net Electric Operating Income after giving effect to the proposed rate increase (Column 5). Finally, the total amount of rate base and capitalization is also shown as well as the calculated overall rates of return.

Schedule 2 calculates the change in revenue requirement required to support a weighted average return of 8.67% on a capitalization of $994,690,811.

Schedule 3 starts with the Company's per book capital balances and adjusts the per book balances to reflect five different adjustments. The net effect of these five adjustments is to decrease the per book capitalization by $24,378,612 (Section V, Schedule 3, Columns 9 - 3). These adjustments will be discussed in greater detail later in my testimony.

Schedule 4 shows the total jurisdictional base case summary (Column 3) brought forward from Schedule 5, Column 6; the effects of the rate case adjustments on the various base case components (Column 4); and the jurisdictional

Net Electric Operating Income and rate base summaries as adjusted (Column 5). Details of each rate case adjustment are shown on Section V Workpaper S-4, Pages 1 - 46. The details of the allocations for these adjustments are also shown on the workpapers.

Schedule 5 shows Total Company per books Operating Revenues, Operating Expense, Net Electric Operating Income, and Rate Base (Column 3). The effects of base case eliminations/adjustments are shown in Column 4. Column 5 is the sum of Columns 3 and 4; and Column 6 is the Kentucky jurisdictional amounts for the components of Net Electric Operating Income and Total Rate Base. All amounts are referenced to the supporting schedules in Section V.

The remaining schedules of Section V contain either allocations of rate base and/or expenses to the retail jurisdiction, using the methods indicated, or important preliminary determinations needed in the allocation process. The titles of each of these schedules are shown in Volume 1 Table of Contents of the Company's filing.

VI. COST ALLOCATION TO THE KENTUCKY RETAIL CUSTOMERS

Q: WHY IS A JURISDICTIONAL COST OF SERVICE NECESSARY?

A: The per book amounts, the modifications, and the adjustments thereto pertain to electric utility operations of the Company for service supplied to all customers, both wholesale and retail. KPCo's retail revenue is approximately 99% of its total revenue; and its wholesale revenue, which includes sales to the cities of Olive Hill and Vanceburg, is approximately 1% of its total revenue. It is, therefore, necessary to segregate costs related only to Kentucky jurisdictional retail service. The results of the allocations are then used to determine the jurisdictional cost of service.

Q: **ARE YOU RESPONSIBLE FOR THE KENTUCKY JURISDICTIONAL METHODOLOGY USED IN THE PREPARATION OF THIS CASE?**

A: Yes. The allocation methodology and the allocation factors used to calculate Kentucky retail jurisdictional amounts were developed by me or under my direction and are shown on the various schedules in the Company's filing. The methodology used in this case is the same methodology used in the Company's last several rate cases.

Q: **WHERE ARE THE ALLOCATION FACTORS OR ALLOCATED AMOUNTS SHOWN ON THE SCHEDULES INCLUDED IN THE FILING?**

A: The allocation between jurisdictional and non-jurisdictional amounts is generally shown in the right-hand column of each appropriate schedule throughout Section V, or on workpapers immediately following each schedule. The results of such allocations are summarized on Schedules 1 through 5 of Section V, which have been previously described.

Q: **WERE THE VARIOUS SCHEDULES OF THE COMPANY'S FILING DEVELOPED IN A CERTAIN SEQUENCE?**

A: Yes. In order to develop all the necessary allocation factors the following sequence of development was used:

	TITLE	SCHEDULE
1.	Energy Allocation Factors	19
2.	Demand Allocation Factors	18
3.	Electric Plant in Service	11
4.	Accumulated Provision for Depreciation	12

5.	Net Electric Plant in Service	13
6.	Electric Operation & Maintenance Expense	7
7.	Various (No specific sequence)	6, 8, 9, 10, 14, 15, 16, 17
8.	Base Case Summary	5
9.	Adjustments	4
10.	Capitalization	3
11.	Revenue Requirement	2
12.	KY PSC Jurisdiction Summary	1

Q: WOULD YOU PLEASE DESCRIBE THE DETERMINATION OF THE ENERGY ALLOCATION FACTORS SHOWN ON SCHEDULE 19?

A: Test period sales of energy to the retail customers were determined and adjusted by applying the appropriate transmission and distribution loss factors to obtain KWH of test period sales of energy to retail customers adjusted to the generation level. The result was divided by the net total Company energy requirements at the generation level to obtain the retail energy allocation factor.

Q: PLEASE DESCRIBE THE DETERMINATION OF THE DEMAND ALLOCATION FACTORS SHOWN ON SCHEDULE 18.

A: The Company serves retail customers under the jurisdiction of the Kentucky Public Service Commission. It also makes sales to two wholesale customers under the FERC jurisdiction. One basis for allocating elements of cost of property between retail and wholesale customers is the respective contribution by each of the two classes to the Company's peak demand. The production demand allocation factor reflects the coincident demand of the Company's retail customers at the time of

Kentucky Power's monthly peak demand; in other words, the kilowatt contribution of those customers to the Company's monthly peak demand. The production demand allocation factor was calculated by dividing the average of twelve monthly retail class coincident demands, adjusted for losses to the generation levels, by the average of the twelve monthly total Company internal peak demands.

The transmission and sub-transmission demand allocation factors are the same as the production demand allocation factor because there are no wholesale loads served at the generation level, or from the bulk transmission system.

Q: PLEASE DESCRIBE THE ASSIGNMENT AND ALLOCATION OF ELECTRIC PLANT IN SERVICE.

A: The electric plant values are the functionalized values as of September 30, 2009. These values are allocated as shown on Schedule 11.

Q: WHAT IS MEANT BY THE FUNCTIONALIZED VALUES OF ELECTRIC PLANT IN SERVICE AS OF SEPTEMBER 30, 2009?

A: The Electric Plant in Service values as of September 30, 2009 are separated into different categories of plant by function (i.e. production plant, transmission plant, distribution plant, general plant and intangible plant).

Q: PLEASE DESCRIBE THE METHOD FOR ASSIGNING AND ALLOCATING ACCUMULATED DEPRECIATION AND AMORTIZATION.

A: Book amounts have been recorded by functional category. These amounts were allocated based on their relationship to allocated Electric Plant in Service and appear on Schedule 12.

Q: PLEASE DESCRIBE THE DETERMINATION OF NET ELECTRIC PLANT.

A: The Net Electric Plant, shown on Schedule 13, is equal to the difference between corresponding values of allocated Electric Plant in Service and the Accumulated Depreciation.

Q: HOW ARE THE COMPANY'S TOTAL OPERATION AND MAINTENANCE (O&M) EXPENSES ADJUSTED ON SCHEDULE 7?

A: The revenues from system sales, which are recorded in the Sales for Resale account, and the revenues from various transmission agreements, which are recorded in the Other Electric Revenues account, have been restated for cost of service purposes as a credit to production expense. In addition, non-regulatory Administrative and General (A&G) expenses have been distributed to the other functions in proportion to related payroll expenses.

Q: WHAT DOES SCHEDULE 6 DEMONSTRATE?

A: Schedule 6 allocates the Company's Total Electric Operating Revenues between Kentucky jurisdiction and FERC jurisdiction based on several allocation factors. The Production Plant revenues were allocated on the Energy Allocation Factor. The Transmission Plant revenues were allocated on Gross Plant Transmission Allocation Factor. The Distribution Plant revenues were allocated 100% to the Kentucky retail customers (a Specific Allocation Factor). Also, Schedule 6 calculates the Operating Revenue - Other Allocation Factor and the Operating Revenues Allocation Factor.

Q: HOW WERE THE ADJUSTED O&M EXPENSE ALLOCATED?

A: Schedule 5 of Section V is the base case summary. The Company starts with the Test Year per book numbers in Column 3 and makes various adjustments (Column 4) to determine the electric utility amounts (Column 5). Then, allocation factors referenced in Column 7 are applied to Column 5 amounts to develop the Kentucky Public Service Commission jurisdiction amounts in Column 6.

Q: PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION, DEPLETION AND AMORTIZATION EXPENSE SHOWN ON SCHEDULE 8.

A: The depreciation expense applicable to each plant functional group is multiplied by the allocation factor. This develops the Kentucky Public Service Commission jurisdiction amount in Column 4.

Q: PLEASE DESCRIBE THE ALLOCATION OF TAXES OTHER THAN FEDERAL INCOME TAXES.

A: Taxes Other Than Federal Income Taxes are shown on Schedule 9. Payroll Related Taxes, except West Virginia Unemployment Insurance, are allocated on the basis of O&M Labor, which is shown on Schedule 7. The Federal Environmental Excise and Kentucky Personal Property and Franchise Taxes are allocated on the basis of Gross Plant-Total. The Kentucky PSC Maintenance, the West Virginia Unemployment Insurance tax, the West Virginia Franchise Fee, and the West Virginia License tax were allocated to the Kentucky retail customers on a 100% basis because the Company incurred these taxes due to the Kentucky employees located in West Virginia providing service to the Kentucky retail customers.

Q: PLEASE DESCRIBE THE COMPUTATION OF JURISDICTIONAL STATE AND CURRENT FEDERAL INCOME TAXES.

A: The computation of jurisdictional Current Federal Income Tax is accomplished by first allocating the various items used in the determination of the Company's total separate return federal taxable income, and applying the statutory federal income tax rate of 35%, as shown on workpapers in Schedule 10. The computation of jurisdictional Deferred Federal income tax is accomplished by applying the appropriate federal income tax rate to the allocated normalized timing differences, as shown on workpapers in Schedule 10, and by amortizing the allocated balances of the embedded Deferred Federal income taxes balances over the appropriate remaining lives. The computation of jurisdictional Deferred Investment Tax Credit is accomplished by amortizing the allocated balances over the appropriate remaining lives. The State income tax is calculated on the basis of operating income before federal income taxes, as shown on Workpaper S-10, page 4.

Q: WERE DEFERRED TAXES AND INVESTMENT TAX CREDITS ALLOCATED?

A: Yes. Each component was allocated as shown on the workpapers in Schedule 10.

Q: PLEASE DESCRIBE THE ALLOCATION OF ELECTRIC PLANT HELD FOR FUTURES USE AS IT APPEARS IN SECTION V, SCHEDULE 14.

A: The test year-end value of items recorded in the account was allocated using appropriate allocation factors as indicated in Column 6. For example, the Production Plant category was allocated on the Production Demand Allocation Factor, the Transmission Plant category was allocated on the Gross Plant

Transmission Allocation Factor and the General Plant category was allocated on Gross Plant Production, Transmission and Distribution Allocation Factor.

Q: PLEASE DESCRIBE THE DETERMINATION AND ALLOCATION OF THE WORKING CAPITAL REQUIREMENT SHOWN ON SCHEDULE 15.

A: The first item, Materials and Supplies, is the test year-end value as assigned by functional category and then allocated as shown in Column 6. Prepayments were allocated on the basis of Gross Plant-Total.

The cash working capital component is calculated by using the standard formula of one-eighth of Total Company O&M expenses. This equals one and one half months of the Company's O&M expenses. The allocation basis for the cash working capital component appears in Column 6.

Q: PLEASE DESCRIBE THE ALLOCATION OF CONSTRUCTION WORK IN PROGRESS (CWIP) AND ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC).

A: Each functional component was allocated as shown on Schedule 16. The total utility amount was multiplied by the appropriate allocation factor. The results were used to calculate the Kentucky Public Service Commission jurisdictional amounts.

Q: PLEASE DESCRIBE THE ALLOCATION OF CUSTOMER ADVANCES FOR CONSTRUCTION, CUSTOMER DEPOSIT AND ACCUMULATED DEFERRED INCOME TAXES AS SHOWN ON SCHEDULE 17.

A: The amounts in the Total Electric Utility column for Customer Advances and Customer Deposits are a result of the Kentucky jurisdiction operations. Therefore, 100% of these amounts are allocated to the Kentucky Public Service Commission jurisdiction column. The Accumulated Deferred Federal Income Taxes were allocated on a Gross Plant - Total allocation factor.

VII. CAPITALIZATION ADUSTMENTS

Q: WOULD YOU PLEASE DESCRIBE EACH OF THE CAPITALIZATION ADJUSTMENTS THAT YOU ARE SPONSORING?

A: Yes. The details of the Capitalization adjustments are set forth on Section V, Schedule 3, as follows:

Adjustment	Schedule 3
1. Big Sandy Coal Stock Adjustment	Column 4
2. Reliability Capital Adjustment	Column 5
3. FRECO A/C 124 Adjustment	Column 6
4. Carrs Site Adjustment	Column 7
5. Non-Utility Property Adjustment	Column 8

Big Sandy Coal Stock Adjustment
(Schedule 3, Column 4)

KPCo's coal inventory target of days supply to have on hand is 30 days at an average burn rate of 10,300 tons per day. At September 30, 2009 the Company had 62 days of coal inventory on hand (641,744 tons / 10,300). Therefore, the Company needs to adjust the coal inventory to 30 days or 309,000 tons (10,300 x 30). The average cost of coal in inventory at September 30, 2009 was $64.71 per ton. The adjusted coal inventory to reflect the Company's 30 day target is $19,995,390 ((30 x 10,300) x $64.71). Since the coal inventory is usually financed with short term debt, the Company decreased its September 30, 2009 short term debt by $21,531,864 ((641,744 x $64.71) - $19,995,390).

Reliability Capital Adjustment
(Schedule 3, Column 5)

As discussed later in my testimony and in Witness Phillips testimony, the Company is proposing to increase the test year's level of O&M expense associated with reliability expenditures by $16,373,854. In addition, there will also be capital spending associated with the increased level of O&M expense proposed by the Company. On average over a three year period, the Company's capital will be increased by $9,422,784. This amount was spread ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at September 30, 2009, the Company used the accounts receivable financing balance at September 30, 2009 and divided it by the total capitalization at September 30, 2009. That result, approximately 4.5%, was spread to short term debt.

Franklin Realty Company Account No. 124 Property
(Schedule 3, Column 6)

The Franklin Realty Company (FRECO) investment, recorded in Account No. 124, was removed ratably from the Company's long term debt, short term debt and common equity capitalization. Since the Company did not have any short term debt at September 30, 2009, the Company used the accounts receivable financing balance at September 30, 2009 and divided it by the total capitalization at September 30, 2009 and that result, approximately 4.5%, was spread to short term debt.

Carrs Site Adjustment
(Schedule 3, Column 7)

The Carrs Site investment was removed from the Company's capitalization ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at September 30, 2009, the Company used the accounts receivable financing balance at June 30, 2005 and divided it by the total capitalization at September 30, 2009 and that result, approximately 4.5%, was spread to short term debt.

Non-Utility Property
(Schedule 3, Column 8)

The Non-Utility investment was removed from the Company's capitalization ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at September 30, 2009, the Company used the accounts receivable financing balance at September 30, 2009 and divided it by the total capitalization at September 30, 2009 and that result, approximately 4.5%, was spread to short term debt.

VIII. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q: WOULD YOU PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A: Yes. The details of the revenue and operating expense adjustments set forth on various pages of Section V, Workpaper S-4. Specifically, I am sponsoring the following adjustments:

Adjustment	Workpaper S-4 Page No.
1. Eliminate Uncollectible Expense Reversal	2
2. System Integration Agreement (SIA) Adjustment	3

3.	Capacity Charge Revenues Adjustment	4
4.	Net Merger Savings Credit Adjustment	5
5.	Fuel Under/(Over) Fuel Revenues	6
6.	FERC Transmission Agreement Investment Adjustment	7
7.	Net Temporary Investment Income and/or Expense	8
8.	AEP Pool Capacity Payments	9
9.	Miscellaneous Service Charges	10
10.	Payment to Carbon Management Research Group	11
11.	Annualization of PSC Maintenance Assessment	12
12.	Big Sandy Plant Maintenance Normalization	14
13.	Adjustment/Annualization Depreciation Expense	16
14.	Amortization of Rate Case Expense	17
15.	Deferred Investment Tax Credit Adjustment	22
16.	System Sales Margin Adjustment	26
17.	Annualization of Intangible Expense	27
18.	Asset Retirement Obligation (ARO) and Accretion (Interest) Expense	29
19.	Adjustment to Remove the Revenues Associated with the System Sales Tracker	31
20.	Reliability Adjustment	41
21.	Correct an Intercompany Billing Error	43
22.	Eliminate Green Pricing Option Rider Revenues	44

Eliminate Uncollectible Expense Reversal
(Section V, Workpaper S-4, Page 2)

Q. EXPLAIN THE ADJUSTMENT TO ELIMINATE UNCOLLECTABLE EXPENSE REVERSAL.

A. During the first half of calendar year 2008 the Company performed an audit of the pole attachments in accordance with the joint use agreements (an agreement between KPCo and several communication companies). The Company found several unauthorized attachments. Subsequently, in August 2008, the Company issued bills to those companies. These bills were also issued in accordance with the joint use agreement. When the bills were issued the revenue was recorded on the Company's books. Due to the fact that some of these revenues were for prior periods of 180 days or greater, a provision for uncollectible accounts was recorded. The Company maintains its financial records in compliance with the accounting profession's Generally Accepted Accounting Principles (GAAP) for accrual based accounting records. The failure to follow this process under GAAP may result in: (i) A potential overstatement of the Company's assets due to failure to record a provision for an uncollectible item and/or (ii) a potential misstatement of the Company's earnings due to missing a write-off of an uncollectible item. The provision for uncollectible accounts was reversed off in October 2008 business when the outstanding amounts were paid. Due to the fact the Company's test year (October 1, 2008 through September 30, 2009) includes only the reversal of the provision for uncollectible accounts associated with this transaction, the result is an understatement in Account No. 9030007 for the twelve month test year. Therefore, an eliminating adjustment in the amount of $4,276,030 is required to adjust Account 9030007 to a test year normal level.

System Integration Agreement (SIA) Adjustment
FERC Docket No. EL08-80-000
(Section V, Workpaper S-4, Page 3)

Q. PLEASE EXPLAIN THE BASIS FOR THE SYSTEM INTEGRATION AGREEMENT ADJUSTMENT.

A. On November 26, 2008 the FERC Ordered AEP to recalculate and reallocate the trading margins from off system sales from June 15, 2000 through March 31, 2006. As a result, in December 2008, KPCo reduced its trading margins in the amount of $12,698,792. Due to the fact that this revenue reduction is a one time nonrecurring event, an adjustment adding back the $12,698,792 was made to normalize the test year revenues.

Capacity Charge Revenues Adjustment
(Rockport Unit Power Agreement)
(Section V, Workpaper S-4, Page 4)

Q. WHAT IS THE CAPACITY CHARGE REVENUES ADJUSTMENT?

A. In accordance with the Stipulation and Settlement Agreement dated October 20, 2004, in Case No. 2004-00420, page 5, Section III (1)(d)(i) the additional revenues collected by Kentucky Power from the retail rate adjustment set forth in Section III (1)(a) and Section III (1)(b) of the Stipulation and Settlement Agreement are not to be considered in establishing Kentucky Power's future retail base rates. These additional revenues include a supplemental payment tied to the settlement of state issues and the extension of the Rockport Unit Power Agreement. Specifically, the Stipulation and Settlement Agreement provides that in any such retail case Kentucky Power may exclude from the test year period the revenues collected pursuant to Section III (1)(a) and Section III (1)(b). Further, Section III (1)(d)(ii) states that Kentucky Power shall collect the additional revenues as set forth Section III (1)(a) and (1) (b) in addition to such base retail rates established by the Kentucky PSC. The costs associated with the underlying Rockport Units 1 and 2 UPSA are to be included in base rates.

Finally, Section (1)(d)(iii) of the Stipulation and Settlement Agreement provides that Kentucky Power will develop, and the other Parties will not oppose, a new tariff that provides for the receipt by Kentucky Power of the additional revenues as described in Section III (1)(a) and Section III (1) (b) that will allow the Company to receive the additional revenue amount in addition to its base rates and other charges. Please see Exhibit EKW-3 for the calculation of the revenue adjustment and Exhibit EKW-11 for the calculations of the new Capacity Charge rates.

Net Merger Savings Credit Adjustment
(Section V, Workpaper S-4, Page 5)

Q. WHAT IS THE NET MERGER SAVINGS CREDIT ADJUSTMENT?

A. In accordance with the Stipulation and Settlement Agreement dated May 24, 1999 in Case No. 99-149, page 5, and in accordance with Attachment A of the Commission's Order dated June 14, 1999 in that case, the Net Merger Savings Credit Tariff began with the first full billing month following thirty days from the consummation of the merger and is to continue until the effective date of the Commission's order changing the Company's base rates after year 8 of this tariff. Year 8 ended in August 2008. The Commission's Order in this proceeding will be the first change in the Company's base rates following year 8 of the Net Merger Savings Credit Tariff. Additionally the Net Merger Savings Credit Tariff is to be discontinued with the effective date of new rates in this proceeding. An adjustment in the amount of $5,218,547 was made to increase revenues to remove the test year credit provided to the customers.

Fuel Under/(Over) Revenues
(Section V, Workpaper S-4, Page 6)

Q. PLEASE EXPLAIN TO THE COMMISSION THE ADJUSTMENTS PROPOSED IN CONNECTION WITH THE OVER/(UNDER) RECOVERY OF FUEL COSTS.

A. As Exhibit EKW- 4 demonstrates, the total test year level of jurisdictional fuel costs was $219,625,727 (Column 9). The total test year level of jurisdictional fuel revenues were $230,614,966 (Column 16), or a difference of $10,989,239 (Column 17). In order to properly design rates so that the appropriate level of revenue is recovered from the Kentucky customers, a negative/credit adjustment of $10,989,239 to revenues is needed. This adjustment trues up the fuel clause revenues with the actual fuel clause expenses. If this adjustment were not made, the rates to be designed would assume that each year the tariffs are in effect the Company would over-recover its fuel costs by $10,989,239. Because of the two-month lag between when costs are incurred and when fuel costs are recovered through the fuel adjustment clause, an adjustment of this type is appropriate, particularly in times of rising fuel costs.

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE OVER OR UNDER-RECOVERY OF FUEL COSTS?

A. Yes. There is an associated deferred tax adjustment in the amount of ($3,846,234) required with the fuel cost adjustment. This book revenue adjustment will not change the Company's taxable income and results in a Schedule M addback on the federal income tax return. The impact of this Schedule M results in a deferred tax impact rather than a current tax impact. The net effect is to reduce the Company's net electric operating income by $7,143,005 ($10,989,239 – $3,846,234). The Company has made this adjustment in its prior rate cases and the Commission has accepted the adjustment.

FERC Transmission Agreement Investment Adjustment
(Section V, Workpaper S-4, Page 7)

Q. WHAT IS THE FERC TRANSMISSION AGREEMENT ADJUSTMENT?

A. This adjustment annualizes the September 30, 2009 levels of transmission revenues associated with the September 30, 2009 level of transmission investment, as well as the change in the September 30, 2009 MLR. This adjustment adjusts the transmission revenues as if these events were in effect for the entire test year. This annualization results in a $1,170,221 reduction in the test year level of transmission expense.

Net Temporary Investment Income and/or Expense
(Section V, Workpaper S-4, Page 8)

Q. PLEASE EXPLAIN THE NET CASH EXPENSE ADJUSTMENT.

A. The net temporary cash expense adjustment reflects the net position between Account No. 4190005 Interest Income and Account No. 43000003 Interest Expense actual amount for the twelve months ending September 30, 2009. The net amount for the twelve months ending September 30, 2009 was an expense of $1,875,974. Because this expense is recorded below the line for accounting purposes, an adjustment in a like amount is required to reflect this cost in the Company's test year cost of service.

AEP Pool Capacity Payments
(Section V, Workpaper S-4, Page 9)

WHAT IS THE AEP POOL CAPACITY CHARGE ADJUSTMENT?

A. As mentioned previously, KPCo is a deficit member of the FERC-approved Interconnection Agreement and KPCo is required to pay a capacity charge to the surplus members every month.

Q. HOW IS THE DEFICIT CALCULATED?

A. KPCo's full requirement customers placed a peak demand of 1,674 MW (January 16, 2009) on its electrical system, which resulted in KPCo constituting 7.069%[1] of the AEP System-East Zone's total peak demand of 23,680 MW at September 30, 2009. The AEP System-East Zone currently has 26,220 MW of total generating capacity. Under the AEP Interconnection Agreement, KPCo is responsible for 1,853.5 MW (26,220 MW x .07069) of the generating capacity. Because KPCo has only 1,453 MW of generating capacity, KPCo is a deficit member in the AEP Pool by 400.5 MW.

Q. WHAT ADJUSTMENTS IS THE COMPANY PROPOSING WITH RESPECT TO THE AEP POOL CAPACITY CHARGE ADJUSTMENTS?

A. KPCo is proposing three different adjustments to the test year level of AEP Pool Capacity payments.

- The first adjustment is a result of a change in KPCo's September 30, 2009 MLR which I will discuss later in my testimony. (Exhibit EKW-13)
- The second adjustment is the result of the expiration of the current contract between Carolina Power & Light (CP&L) and AEP Indiana Michigan Power

[1] KPCo's MLR percent changed as of September 2009 from 7.069% to 7.084% as discussed later in my testimony.

Company (I&M). Beginning January 1, 2010, 250 MW currently under contract with CP&L will come back to I&M. This action will affect the following items in the AEP Pool calculations: (1) both the AEP System's total Member Primary Capacity as well as I&M's total Member Primary Capacity will increase by 250 MW, (2) KPCo's obligation will increase by approximately 17.7 MW (250 MW X the revised MLR 7.084%), and (3) I&M surplus will become a larger percentage of the total AEP Pool surplus capacity. (Exhibit EKW-14) This will increase KPCo's deficit and accordingly increase KPCo's capacity charge.

- The third adjustment reflects the known and measurable changes in the investment levels at September 30, 2009 used in the Pool Capacity Payments calculations. Exhibit EKW-15 and 16)

The net result of the above adjustments is to increase KPCo's annual Pool Capacity Payments by $8,907,066 (See Section V, Workpaper S-4, Page 9).

Miscellaneous Service Charges
(Section V, Workpaper S-4, Page 10)

Q WHAT ARE THE MISCELLANEOUS SERVICE CHARGE ADJUSTMENTS?

A. Kentucky Power charges its' customers for Reconnects, Collection Trips, Bad Checks and meter test charges. As I will discuss later, the Company is proposing to increase the rates charged for such services. This adjustment annualizes test year revenues based upon the proposed new rates. The impact is to increase KPCo revenues by $781,638. (See Exhibit EKW-6)

Payment to Carbon Management Research Group

(Section V, Workpaper S-4, Page 11)

Q. WHAT IS THE CARBON MANAGEMENT RESEARCH EXPENSE ADJUSTMENT?

A. On October 31, 2008, the Kentucky Public Service Commission in Case No. 2008-00308, authorized KPCo to record the annual payments to Carbon Management Research Group (CMRG) as a regulatory asset. This partnership has a duration of ten years with an annual payment of $200,000. There will be approximately 96 months left on this commitment when new rates in this proceeding are scheduled to be established. Therefore, an adjustment of $249,996 (($2,000,000/96) X 12) is required to recover the total cost of the commitment through its termination.

Annualization of PSC Maintenance Assessment
(Section V, Workpaper S-4, Page 12)

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT IN CONNECTION WITH THE ITS KENTUCKY PSC ASSESSMENT FEE EXPENSE?

A. Yes. The Company received an invoice from the Commonwealth of Kentucky on June 17, 2009 in the amount of $749,755 for the Kentucky PSC Assessment fee. During the test year the Company recorded $690,216 in Kentucky PSC assessment fees. The Company's proposed adjustment is $59,544.

Big Sandy Plant Maintenance Normalization
(Section V, Workpaper S-4, Page 14)

Q. HOW WAS THE BIG SANDY PLANT MAINTENANCE ADJUSTMENT CALCULATED?

A. Because KPCo has one generating plant, and because plant maintenance is performed on a cyclical basis, an adjustment to the test year plant maintenance expense is required to reflect an annualized level of plant maintenance in the Company's test year cost of service. The Company took the level of steam plant maintenance expense for the twelve months ended June 30, 2007, 2008 and 2009 and adjusted those levels of plant maintenance expense to a constant dollar amount using the Handy-Whittman total steam production plant index. Once the annual constant dollar amounts were calculated, the three year total was divided by three to arrive at an annual normal level of steam plant maintenance expense. That result was compared to the test year level amount. The difference of $3,243,445 is an increase proposed by the Company to the test year cost of service.

Adjustment/Annualization Depreciation Expense
(Section V, Workpaper S-4, Page 16)

Q. PLEASE EXPLAIN THE DEPRECATION ANNUALIZATION ADJUSTMENT.

A. The annual depreciation expense is calculated by multiplying the new depreciation rates supported by Witness Henderson in the depreciation study, by the respective functional classes of depreciable property investment balances. Comparing the annual depreciation expense that was calculated using the new depreciation rates versus the annual depreciation expense recorded in the test year, the difference is a required increase adjustment in the amount of $11,934,322.

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE ANNUALIZATION OF THE COMPANY'S DEPRECIATION EXPENSE?

A. Yes. There is an associated deferred tax adjustment in the amount of $ 2,629,012 ($11,934,322 X .35 X .6294). This book depreciation adjustment will not change the Company's taxable income and results in a Schedule M addback on the federal income tax return. The impact of this Schedule M results in a deferred tax impact rather than a current tax impact. Only 62.94% of this Schedule M relates to normalized book versus tax depreciation. The remainder relates to the reversal of prior flow-thru book / tax basis differences such as AOFUDC.

Amortization of Rate Case Expense
(Section V, Workpaper S-4, Page 17)

Q. HOW WAS THE RATE CASE EXPENSE DEDUCTION CALCULATED?

A. The Company's estimated cost for this rate proceeding is $561,000. Consistent with the Commission's past treatment of such expenses, the Company is proposing to recover this cost over a three-year period. Since there was no rate case costs recorded in the test year, an adjustment of $187,000 ($561,000/3) to the Company's test year expenses is needed. Expenses included in this amount are costs that would not have been incurred except for the filing of this rate case, such as Outside Legal, Cost of Equity Witness, Demolition Study, Legal Publication Notice and any Employee Out-of-pocket Expenses and Contract Labor Costs incurred exclusively associated with this rate case filing.

Deferred Investment Tax Credit Adjustment
(Session V, Workpaper S-4, Page 22)

Q. WHY IS KENTUCKY POWER PROPOSING A DEFERRED INVESTMENT TAX CREDIT (DITC) ADJUSTMENT?

A. Investment Tax Credits were claimed for eligible property additions on the Federal income tax returns of KPCo starting in the mid-1970's and continuing until the credits were no longer available. Under the tax normalization rules, these credits were deferred and were amortized over the life of the property – generally 30 years

– through cost of service or income tax expense under the Company's §46(f)(2) ITC Election. The annual DITC amortization is starting to decrease each year as the DITC vintage deferral years become fully amortized. This is a known and measurable event for the first year KPCo's proposed new rates will be in effect. An adjustment was calculated based on the 12 month period beginning after the new rates are anticipated to go into effect (July 1, 2010). The revised annual DITC amortization amount was based on six months of calendar year 2010 amortization and six months of 2011 amortization. The effect of this adjustment is to decrease KPCo's net electric operating income by $292,039. (See Exhibit EKW-17)

<u>System Sales Margin Adjustment</u>
<u>(Section V, Workpaper S-4, Page 26)</u>

Q. WHAT IS THE SYSTEM SALES MARGIN ADJUSTMENT?

A. During the test year the Company realized $15,614,155 of system sales margins. As a result of the change in the monthly MLR (as explained later in my testimony) from 7.069% to 7.084%, the Company's monthly System Sales will increase (Column 4). Also, included in the system sales margin total are $60,488 associated with ancillary services (Column 5) and $392,189 for sales for resale associated with the Carolina Power & Light 250 MW sale from the Rockport Plant (Column 6). The CP&L contract expires on January 1, 2010. Upon the contract's expiration, these revenues will stop and therefore, they should be removed from the monthly base.

<u>Annualization of Intangible Expense</u>
<u>(Section V, Workpaper S-4, Page 27)</u>

Q. PLEASE EXPLAIN THE PROPOSED ANNUALIZATION OF THE COMPANY'S INTANGIBLE EXPENSE.

A. The Company annualized the September 30, 2009 monthly intangible expense and compared the result with the level of intangible expense included in the test year. The difference of $177,213 was reflected as an increase to the Company's cost of service.

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE ANNUALIZATION OF THE COMPANY'S INTANGIBLE EXPENSE ADJUSTMENT?

A. Yes. There is an associated deferred tax adjustment in the amount of $62,025 ($177,213 X .35). This book adjustment will not change the Company's taxable income and results in a Schedule M addback on the federal income tax return. The impact of this Schedule M results in a deferred tax impact rather than a current tax impact.

Asset Retirement Obligation (ARO) and Accretion (interest) Expense (Section V, Workpaper S-4, Page 29)

Q. WHAT IS THE ASSET RETIREMENT OBLIGATION AND ACCRETION ADJUSTMENT?

A. As I will discuss later in my testimony, the Company is proposing two adjustments whereby the cost of Company's asset retirement obligation (ARO) associated with the removal of asbestos at the Big Sandy Plant, and the associated accretion (interest) cost pursuant to Statement of Financial Accounting Standards (SFAS) 143, are included in the cost of service.

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE ASSET RETIREMENT OBLIGATION AND ACCRETION ADJUSTMENT?

A. Yes. There is an associated deferred tax adjustment in the amount of $165,437 ($472,677 X .35). This book adjustment will not change the Company's taxable income and results in a Schedule M addback on the federal income tax return. The impact of this Schedule M results in a deferred tax impact rather than a current tax impact.

Adjustment to Remove the Revenues Associated with the System Sales Tracker (Section V, Workpaper S-4, Page 31)

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ASSOCIATED WITH SYSTEM SALES.

A. The System Sales Tracker in effect during the test year worked off of a total annual base of $24,855,326. The twelve monthly amounts that totaled the $24,855,326 base were the actual level of monthly system sales margins realized by KPCo during the Company's last test year ending June 30, 2005. Then in any month in which the actual system sales margin was above or below the monthly base amount, the difference was shared between the Customer and the Company on a 70/30% up to $30,000,000 in total system sales margins and a 60/40% basis, if greater than the $30,000,000 level during the twelve expense months of February through January. During the twelve revenue months ending September 30, 2009, there were nine months in which the monthly system sales margin fell below the monthly base, and three months in which the monthly level of system sales margin was above the monthly base. The net effect during the twelve months ending September 30, 2009 was that the customers paid an additional $1,486,754 in revenues. These are one time nonrecurring revenues. For ratemaking purposes, the Company has reclassified these system sales margins as a negative expense. Once new rates are established, and in order to properly design rates so that the appropriate level of revenues and/or expenses are recovered from the Kentucky customers, an increase in the test year operation and maintenance expenses of $1,486,754 is required.

Reliability Adjustment
(Section V, Workpaper S-4, Page 41)

Q. **WHAT IS THE PROPOSED DISTRIBUTION RELIABILITY ADJUSTMENT?**

As explained by Witness Phillips, the Company is proposing to increase its test year reliability O&M expenditures by $16,373,854. There is an associated additional capital expenditure of $21.4 Million. In addition, during each of the next three years the Company will have on average an additional capital investment of $9.4 Million in distribution reliability measures.

Q **WHY IS THE COMPANY MAKING THESE INCREASED EXPENDITURES AND CAPITAL INVESTMENTS?**

A. Please refer to the testimony of Witness Phillips for a detailed explanation of the proposed increase to the Company's test year reliability expenses and capital. In addition, as explained by Witness Mosher, these additional revenues will allow the Company to comply with the Commission's November 19, 2009 Report relating to the September 2008 Wind Storm and the January 2009 Ice Storm.

Correct an Intercompany Billing Error
(Section V, Workpaper S-4, Page 43)

Q. PLEASE EXPLAIN THE INTERCOMPANY BILLING REVENUE CORRECTION.

A. During the revenue month of September 2009 an entry reducing KPCo's monthly revenues was erroneously made on KPCo books and records in the amount of $508,868. This entry was reversed in October 2009. An adjustment adding back $508,868 of revenues is required to adjust the test year revenues to a normal level.

Eliminate Green Pricing Option Rider Revenues
(Section V, Workpaper S-4, Page 44)

Q. WHAT IS THE GREEN PRICING OPTION RIDER REVENUE ADJUSTMENT?

A. During the test year, KPCo realized $434 of Green Pricing Option Rider. Because these revenues are collected from the customers at their election above the base level of revenues, they should be removed from the test year revenues.

IX. FURTHER EXPLANATION OF CERTAIN ADJUSTMENTS

Asset Retirement Obligation and Accretion Adjustment

Q: WOULD YOU PLEASE EXPAND ON YOUR ARO DEPRECIATION AND ACCRETION ADJUSTMENTS?

A: Yes. Currently KPCo is recovering the projected cost of future removal of the asbestos at the Big Sandy Plant in its depreciation rates established by the Commission's Order dated October 28, 1991 in Case No. 91-066. The Statement of Financial Accounting Standards (SFAS) 143, effective January 1, 2003, requires the recording at fair value of a liability for any legal obligations for asset retirements in the period incurred, and the establishment of a corresponding asset that will be depreciated over the useful life of the asset. SFAS 143 also requires that the cumulative effect of the change in accounting principal be recognized for the cumulative accretion and accumulated depreciation which would have been recognized had SFAS 143 been historically applied. In the fourth quarter of 2005, KPCo implemented the Financial Accounting Standards Board (FASB) Interpretation 47 (FIN 47) which interpreted the application of SFAS 143 to clarify the term conditional asset retirement obligation. It also clarified when an entity is deemed to have sufficient information to reasonably estimate the fair value of an ARO.

Q: HOW DID FIN 47 AFFECT KPCO?

A: The implementation of FIN 47 resulted in KPCo recording an ARO for asbestos-related removal costs with a charge to FERC Account 108, Accumulated provision for depreciation of electric utility plant. Monthly thereafter, KPCo charged Account 108 instead of recording monthly ARO depreciation and accretion expense.

Q: DOES WITNESS HENDERSON'S DEPRECIATION STUDY FILED IN THIS PROCEEDING INCLUDE ANY COSTS ASSOCIATED WITH THE REMOVAL OF ASBESTOS AT THE BIG SANDY PLANT?

A: No. Because asbestos removal costs are required to be accounted for as AROs in accordance with FIN 47, the Company did not include the estimated cost of asbestos removal in the depreciation study.

Q: WHAT IS THE RATEMAKING RESULT OF THE ACCOUNTING FOR THE AROS THAT YOU DESCRIBED ABOVE?

A: The ratemaking result is that the costs of the AROs which were a part of the cost of removal in the Company's previous depreciation rates are now included in the ARO depreciation and accretion adjustments. These adjustments allow for the Company to comply with both the SFAS 143 and FASB's Interpretation 47.

Q: HOW WERE THE ARO DEPRECIATION EXPENSE AND THE ARO ACCRETION EXPENSE ADJUSTMENTS CALCULATED?

A: The monthly ARO depreciation expense of $14,959 times 12 results in an annual ARO depreciation expense of $179,508. The monthly ARO accretion expense of $24,990 times 12 resulted in an annual ARO accretion expense of $299,880, for a total adjustment of $479,388.

<u>Change in KPCo's September 30, 2009 MLR</u>

Q: WOULD YOU PLEASE EXPLAIN THE CHANGE IN KPCo's SEPTEMBER 30, 2009 MLR?

A: Discovery of metering equipment discrepancies between Buckeye Power, Inc. (a non-affiliated company) and Ohio Power Company (OPCo) resulted in overstating OPCo's load. The AEP System's total load has to equal. If OPCo's load was overstated the other operating companies' September 2009 load was understated. Exhibits EKW-12 demonstrates the changes in the MLR for each operating company.

Q: WHAT COMPANY ADJUSTMENTS ARE AFFECTED BY THE CHANGE IN THE SEPTEMBER 2009 MLR?

A: The change in the September 2009 MLR affects the FERC Transmission Agreement Revenues Adjustment (Section V, Workpaper S-4, page 7), the AEP

Pool Capacity Payment Adjustment (Section V, Workpaper S-4, page 9), and the System Sales Margin Adjustment (Section V, Workpaper S-4, page 26). The change in the MLR will also affect the base environmental costs established for the Environmental Surcharge Tariff (Exhibit EKW-10).

Q. WHAT EFFECT DOES THE COMPANY'S PROPOSED TRANSMISSION ADJUSTMENT TARIFF HAVE ON THE COMPANY'S TEST YEAR REVENUE REQUIREMENT?

A. As stated in Witness Roush's testimony the test year annual effect of the Transmission Adjustment Tariff is to reduce the Company's revenue requirement by $7,038,463.

X. <u>TARIFF ADDITIONS AND CHANGES</u>

Q: IS THE COMPANY PROPOSING ANY PERMANENT ADDITIONS OR CHANGES TO THE COMPANY'S TARIFFS CURRENTLY ON FILE WITH THE COMMISSION?

A: Yes. The additions/changes are indicated in the right-hand margin of each tariff sheet attached in Section III, Exhibit EKW-5. Some of the changes are minor text changes and are self-explanatory. I will address the major changes in my testimony, beginning with the new tariffs and charges being proposed, followed by changes to the Company's current terms and conditions and current electric rate schedules.

<u>New Tariffs</u>

Q: IS THE COMPANY PROPOSING ANY NEW TARIFFS IN THIS PROCEEDING?

A: Yes, the Company is proposing the following new tariffs: Sheet Nos. 6-8 through 6-9 Experimental Residential Service-Time-of-Day2; Sheet Nos. 7-3 through 7-4 Experimental Small General Service-Time-of-Day; Sheet Nos. 9-4 through 9-6 Large General Service-Time-of-Day; Sheet Nos. 24-1 through 24-7 Emergency Curtailable Service-Capacity & Energy Rider; Sheet Nos. 32-1 through 32-4 Alternate Feed Service Rider; Sheet No. 33-1 Utility Gross Receipt Tax Tariff; Sheet No. 34-1 Kentucky Sales Tax Tariff and Sheet Nos. 35-1 and 35-2 Transmission Adjustment Tariff. In addition to these new tariff sheets, the Company is proposing new charges to Sheet No. 10-1, Quantity Power Tariff to add minimum demand charge language and rates. Also, the Quantity Power Tariff will offer the energy charge per KWH in two steps, the first 350 kWh per kW of monthly on-peak billing demand, and in excess of 350 kWh per KW of monthly on-peak billing demand. Sheet No. 14-1 Outdoor Light has been modified and the Company is proposing to offer new outdoor lighting options.

Q. WHAT TARIFFS WILL BE DISCUSSED IN WITNESS ROUSH'S TESTIMONY?

A. Witness Roush will discuss the following proposed tariffs:

- Experimental Residential Service - Time-of-Day2 Tariff
- Experimental Small General Service – Time-of-Day Tariff
- Large General Service – Time-of-Day Tariff
- Quantity Power Tariff
- Emergency Curtailable Service-Capacity & Energy Rider Tariff
- Alternate Feed Service Tariff

- Transmission Adjustment Tariff
- System Sales Clause Tariff

Utility Gross Receipt Tax Tariff (School Tax) Tariff

Q: PLEASE DESCRIBE THE UTILITY GROSS RECEIPT TAX TARIFF.

A: The utility gross receipts license tax for schools is assessed on gross receipts derived from the furnishing of utility services and/or cable and direct broadcast satellite services within a school district. The service provider collects the tax based on the rate established by the local authority. The rate cannot exceed 3 percent. This tariff memorializes Kentucky Power's right under KRS 160.217 to increase its rates in an amount equal to the utility gross receipts license tax for schools it is required to pay.

Kentucky Sales Tax Tariff

Q: PLEASE DESCRIBE THE KENTUCKY SALES TAX TARIFF.

A: This tariff memorializes the Company's right under KRS 139.210 to recover from its applicable customers the 6% Kentucky sales tax on certain electric sales.

Changes to the Company's Current Tariffs

Q: PLEASE GIVE AN OVERVIEW OF THE CHANGES MADE TO THE COMPANY'S CURRENT TARIFFS.

A: As stated earlier in my testimony, the additions/changes are indicated in the right-hand margin of each tariff sheet attached in Section III, Exhibit EKW-5. Some of the changes are minor text changes and are self-explanatory. I will discuss the major changes below.

Terms and Conditions of Service
Bill Format

Q. ARE THERE ANY CHANGES TO THE COMPANY'S CURRENT BILL FORMAT BEING PROPOSED IN THIS PROCEEDING?

A. Yes. There have been minor changes to Kentucky Power Company's bill format. In the upper left hand corner, the customer bill stub has been modified to remove the customer's account number and to reflect a coding reference: first space is to show the type of bill being issued: R (Regular), D (Disconnect), O (Other, generally shown on return check notices); the second space reflects the AEP operating company alpha code, i.e. K (Kentucky) O (Ohio), WV (West Virginia) etc.; and the third space shows the meter number. Effective with the Commission's approval in this proceeding, the final Net Merger Savings Credit Balancing Adjustment Factor (B.A.F.) will be applied to customer billings in the second month following the effective date of the Commission's Order in this proceeding changing the Company's base rates. Once the final Net Merger Savings Credit B.A.F. has been billed, the Net Merger Savings Credit and the Associated B.A.F. will be discontinued.

Terms and Conditions of Service
Special or Nonrecurring Charges

Q: WHAT ARE SPECIAL OR NONRECURRING CHARGES?

A: Special or Nonrecurring charges are charges to customers due to a specific request for certain types of services for which, when the activity is completed, no additional charges will be incurred. Such charges are intended to be limited in nature and to recover the specific cost of the activity.

Q: DOES THE COMPANY HAVE ANY SPECIAL CHARGES CURRENTLY ITS TERMS AND CONDITIONS OF SERVICE?

A: Yes. The Company currently has four Special Charges. They are: reconnect for nonpayment; termination or field trip; return check charge; and meter test charge.

Q: WHEN WERE THE CURRENT SPECIAL CHARGES ESTABLISHED?

A: The Company's current Special Charges were first established in Case No. 7164 with a test year ended March 31, 1978. The existing Special Charges were modified in Case No. 2005-00431, with a test year of June 30, 2005.

Q: DOES THE COMPANY HAVE DIFFERENT CHARGES WITHIN THE RECONNECT FOR NONPAYMENT CATEGORY?

A: Yes. The Company has four different categories of reconnect for nonpayment. The four categories are: reconnect for nonpayment during regular hours; reconnect for nonpayment when work continues into overtime at the end of the day and no call out is required; reconnect for nonpayment when call out is required and an employee must be called in to work on an overtime basis to make the reconnection; and reconnect for nonpayment when an employee is called out on a Sunday or Holiday when double time is required.

Q: WHY DOES THE COMPANY HAVE FOUR DIFFERENT CATEGORIES OF RECONNECT FOR NONPAYMENT?

A: The Company has four different categories of reconnect for nonpayment charges to recognize the unique costs associated with each of the four types of reconnections. For example, when the Company reconnects a customer after normal business hours, an employee is called out and the Company is obligated to pay that employee time and half for a minimum of two hours. When the Company reconnects a customer on a Sunday or a Holiday, an employee is called out and the Company is obligated to pay the employee double time for a minimum of two hours. Also, the Company incurs different costs depending upon the time of day (or night) the work is performed. The intent of the Special Charges is to assign the cost incurred by the Company to perform the specific activity to the customer who required the Company to incur those costs. The customer has the ability to decide what charge they want to incur.

Q: HOW WERE THE AMOUNTS OF THE DIFFERENT SPECIAL CHARGES DETERMINED?

A: The methodology used to determine the Special Charges is the same methodology that was used in Case Nos. 7164 and 91-066. Using data and information supplied by the field employees and their supervisors the average time to perform the different activities was calculated. The Company then accumulated the total labor costs, transportation costs, fringe benefit costs and any other associated cost incurred to arrive at the total cost to perform each of the different activities (See Exhibit EKW-6).

Q: **WOULD YOU PLEASE WALK US THROUGH ONE OF THE RATE CALCULATIONS ON EXHIBIT – 6?**

A: Yes. First, the Company used either the average time it takes to perform the activity or, in the activities where call out is required, the amount of time the Company is required to pay the employee to perform the activity (line 1). Second, the Company determined the average transportation time it takes to perform the different activities (line 2). Third, the hourly labor rate for the classification of the employees who perform the different activities (line 3) multiplied by the average time to perform the different activities determined the labor cost (line 6). Fourth, the hourly transportation rate (line 7) was multiplied by the transportation hours (line 2) to arrive at the transportation cost (line 8) to perform the different activities. Fifth, the fringe benefit rate (line 9) was multiplied by the labor cost (line 6) to arrive at the benefit cost (line 10) associated with the different activities. Sixth, with respect to the bad check charge, there is an average bank fee of $3.54 that is charged to the Company by the bank for each bad check the Company deposits. This cost is included in the bad check charge calculations (line 11). Line 12, the total cost line, is the accumulation of the labor cost (line 6) plus the transportation cost (line 8) plus the benefit cost (line 10) and in the case of the bad check charge the bank fees associated with depositing a bad check.

Q: **WHAT IS THE ADDITIONAL ANNUAL REVENUE THE COMPANY WOULD ANTICIPATE BY INCREASING THE SPECIAL CHARGES AS DESCRIBED ON EXHIBIT – 6, LINE 13?**

A: If the suggested charges (line 13) were in effect for the twelve months ending September 30, 2009, and the number of transactions for each activity remained the same, the total increase in the Company's Special Charges revenue would have been $781,638 (See Exhibit EKW-6, line 17, Column 8).

Q: **DID THE COMPANY PERFORM THE ABSORPTION TEST REQUIRED BY 807 KAR 5:011, SECTION 10 (2) FOR THESE CHARGES?**

A: Yes. The Company calculated the after tax effect of the $781,638 in additional revenues. The result is an increase in net income of $477,581 (See Exhibit EKW-6 line 20 Column 8). Using the September 30, 2009 thirteen-month average common equity of $412,359,477, the earned return on equity during the test year would have increased by 0.12% or from 2.90% to 3.02%.

Q: WHAT WAS THE COMPANY'S MOST RECENT CASE IN WHICH THIS COMMISSION AUTHORIZED A RETURN ON EQUITY AND WHAT THE AUTHORIZED RATE?

A: The Company's most recent case was an Environmental Case No. 2009-00038, for the period ending December 31, 2008. By Order dated May 14, 2009, the authorized return on equity was 10.5%.

Q: WHAT IS ILLUSTRATED ON EXHIBIT EKW-7?

A: Exhibit EKW-7 shows the total number of each of the special nonrecurring charges per month for the different revenue classes. For example, there were 10,398 reconnect charges at the amount of $12.94 each in the residential class of customer.

Q: WHAT IS DEMONSTRATED ON EXHIBIT EKW-8?

A: Exhibit EKW-8 takes the total number of each of the special nonrecurring charges for the twelve months ending September 30, 2009, and spreads the proposed increased revenue among the different customer classes. For example, with respect to the reconnect charge, not requiring any overtime, the Company is proposing a $40.00 increase per transaction. This results in an increase of $296,848 in total reconnect revenues. The residential customer class would see an increase of $281,370 of the $296,848 total revenues, assuming the same number of transactions during the first year of the new nonrecurring charges.

Q: BY INCREASING THE NONRECURRING CHARGES TO THE COMPANY'S ACTUAL COST OF EACH TRANSACTION, WHAT WILL BE THE PERCENT OF INCREASE BY CUSTOMER CLASS?

A: Exhibit EKW-8 illustrates the customer class percent of change. For example, adding the nonrecurring charges to the Company's actual cost of each transaction will produce a 0.3563% increase in revenue for the residential class of customers. Again this assumes the same number of each transaction in the first year of the new nonrecurring charges as were incurred during the twelve months ending September 30, 2009.

Q: WHAT IS DEMONSTRATED ON EXHIBIT EKW-9?

A: Exhibit 9 breaks down for the test year the actual nonrecurring revenues by the different charges and by the different customer classes. For example, using the current $12.94 reconnect charge the Company did realize a total $134,550.12 from the residential class; $7,362.86 from the commercial class; and $38.82 from the industrial class for a total of $141,951.80.

Q. ARE THERE ANY OTHER CHANGES TO THE NONRECURRING CHARGES BEING PROPOSED BY THE COMPANY?

A. Yes. The Company is proposing a reconnection charge for all customers where service has been disconnected at the request of the customer and the same customer requests that the service be reconnected within a period of twelve (12) months from the date that the service was disconnected.

<u>Terms and Conditions</u>

Q: ARE THERE ANY OTHER PROPOSED CHANGES TO THE COMPANY'S TERMS AND CONDITIONS OF SERVICE TARIFF THE COMPANY IS REQUESTING?

A: The Company is proposing to clarify the following in the terms and conditions:

(1) Sheet No. 2-3, paragraph 4 (D), Additional Deposit Requirement. The language was modified to allow the Company the ability to impose additional deposit requirements for non-residential customers who fail to maintain a satisfactory payment record; it will also allow the Company to require an additional or supplemental deposit if the customer's credit rating falls to a C level or below, as reported by a national credit reporting agency.

(2) Sheet No. 2-5, paragraph 7, Company's Liability. The language pertaining to the ownership and responsibility for the meter base, connection and grounds and associated internal parts of meter base was modified to make clear the Company's current practices. No change in substance was made. In addition, a provision was added excluding liability for damages, whether direct, incidental or consequential, including, without limitations, loss of profits, loss revenue, or loss of production capacity occasioned by interruptions, fluctuations or irregularity in the supply of energy, loss or damage caused by the disconnection or reconnection of Company facilitates, as well as for loss or damages caused by the theft or destruction of Company facilities by a third party.

Contract Service – Interruptible Power Tariff

Q: PLEASE DESCRIBE THE CHANGE TO THE C.S.-I.R.P. TARIFF.

A: The Company is proposing to remove the availability requirement of customer operating at sub-transmission voltage or higher. The capacity contract requirement is being changed from less than 5,000 kW to 1,000 kW.

Outdoor Lighting Tariff

Q: PLEASE DESCRIBE THE ADDITIONS TO THE OUTDOOR LIGHT TARIFF.

A: In response to customer inquiries, the Company is offering a new service for a 250 Watt high pressure sodium overhead light. Under the post-top lighting service category, the Company also is offering three service offerings of Shoebox high pressure sodium fixtures. The Shoebox is a modern fixture with optimal functionality and available for streets, highways, parking lots, open areas, neighborhoods, commercial driveways and industrial sites. Finally, under the flood lighting service, the Company is offering two metal halide Mongoose fixtures which provide optimal lighting control in a compact design. This type of fixture is ideal for applications where poles cannot be in the roadway "clear zone," or if pole setback from the roadway is greater than 12 feet. These fixtures are available for streets, highways, parking lots, open areas, commercial driveways, and industrial sites.

System Sales Clause Tariff

Q: ARE YOU RESPONSIBLE FOR FILING THE MONTHLY SYSTEM SALES CLAUSE TARIFF INFORMATION WITH THE COMMISSION?

A. Yes.

Q. WILL YOU PLEASE BRIEFLY DESCRIBE THE CURRENT SYSTEM SALES CLAUSE TARIFF?

A. Yes. The System Sales Clause Tariff is a mechanism for tracking the off system sales KPCo makes to a non-affiliated utility. Depending on the level of off system sales margins, some, all or an amount in excess of these margins are used to reduce the rates paid by Kentucky Power's customers.

Q. HOW DOES THE CURRENT SYSTEM SALES CLAUSE TARIFF OPERATE?

A. Currently there are twelve monthly amounts that total $24,855,326. Depending on the amount of a particular month's off system sales margins, the customers either receive a credit or a charge that is applied to their monthly bill. The amount of the credit or charge is calculated by comparing a particular month's off system sales margins to the same month's amount built into base rates. If the actual monthly off system sales margins exceed the amount built into base rates for that same month, a portion of the difference is credited to the customers' bills. If the actual monthly off system sales margins are less than the amount built into base rates for that same month, a portion of the difference is a charge to the customers' bills. The percentage charged or credited to the customers is either 70% up to $30,000,000 in total system sales margins or 60% if greater than the $30,000,000 level during the twelve expense months of February through January (the Company bears or receives the other 30% or 40%).

Q. WILL YOU PLEASE EXPLAIN WHAT IS MEANT BY THE TERM "BUILT INTO BASE RATES"?

A. Yes. As part of the settlement of the last rate case the parties agreed the Company would reduce the cost of service used to design the rates customers are currently paying by the total off system sales margins realized during the June 30, 2005 test year or $24,855,326. That is, the Company's base rates reflect the customers receiving the benefit of $24,855,326 in off system sales margins.

Q. PLEASE EXPLAIN THE TWO DIFFERENT PERCENTAGE AMOUNTS USED IN THE CALCULATION OF THE CUSTOMERS' SHARE.

A. In connection with the settlement of the Company's last rate case, the Commission approved the parties' settlement agreement that a monthly amount of off system sales margins, which varies from month-to-month, would be assumed to have been included for purposes of the System Sales Clause Tariff. These twelve monthly amounts are built into existing base rates and total $24,855,326. Under the agreement, the difference between the actual level of monthly off system sales margin and the corresponding month's level built into base rates is shared (or borne) on a 70 (customers)/30% (Company) up to and including $30,000,000 in total off system sales margins within the twelve month period. After a $30,000,000 level in off system sales margins during the twelve month period is attained, the additional off system sales margins are split 60 (customers)/40% (Company) for the remaining months of the twelve month period.

Q. WILL YOU PLEASE GIVE SOME EXAMPLES OF HOW THE CURRENT SYSTEM SALE CLAUSE TARIFF OPERATES?

A. Yes. In the first example, assume the Company realizes $797,692 of off system sales margin during the expense month of April. The base amount of off system sales margin built into base rates for April is $2,706,860. The total level of off system sales margin from February through April was less than $30,000,000. The difference of $1,909,168 ($2,706,860 - $797,692) between the amount built into rates for April and the actual level of off system sales margins was charged 70%, or $1,336,418, to the customers through the System Sales Clause Tariff (two months later during June). The remaining 30%, $812,058 ($2,706,860 - $1,336,418), was borne by the Company.

The functioning of the Tariff in a month in which the off system sales margins exceed the amounts built into base rates for a particular month can be illustrated through a second example. Assume the Company realized $3,687,501 in off system sales margin during the expense month of September. The base amount of off system sales margin built into base rates for September is $1,497,772. The total level of off system sales margin from February through September was greater than $30,000,000. For September, then, 60% (or $1,319,837) of the difference of $2,199,729 ($3,697,501 - $1,497,772) would be shared with the customers by a credit on their monthly bill through the System Sales Clause Tariff (two months later during November). The remaining 40%, or $869,892 ($2,199,729 - $1,329,837), would be retained by the Company.

Q. HOW DID THE ACTUAL MARGINS REALIZED BY KENTUCKY POWER ON OFF SYSTEM SALES BEFORE ANY SHARING COMPARE

TO THE BENEFITS RECEIVED BY THE CUSTOMERS UNDER THE SYSTEM SALES CLAUSE TARIFF?

A. The total off system sales margins received by KPCo in the test year was substantially less than the benefits realized by KPCo's customers. Under the settlement agreement, KPCo's annual revenue requirement from base rates was reduced to reflect the Company's most recent rate case test year actual level of system sales margin of $24,855,326. Thus, if KPCo actually received $24,855,326, the customer would receive the total amount. KPCo would benefit only when sales exceeded $24,855,326. In fact, the actual level of off system sales margin realized during the September 30, 2009 test year was only $15,614,155. Thus, KPCo received no net economic benefit from its system sales activities; rather, KPCo sustained a substantial economic loss while the customers received a significant and disproportionate amount of the benefit.

Q. PLEASE DESCRIBE THE ECONOMIC LOSS THAT KPCo INCURRED.

A. KPCo received $15,614,155 in the off system sales activity along with the $1,486,754 the customers paid through the System Sales Clause Tariff for a total amount of $17,101,909. However, revenue requirement for the retail customers had been reduced by $24,855,326. Therefore, KPCo sustained an economic loss of $7,754,417.

Q. PLEASE DESCRIBE THE BENEFIT THAT CUSTOMERS RECEIVED.

A. The customers received $24,855,326 through reduced base rates. That amount was reduced by $1,486,754 customers paid through the System Sales Clause Tariff to yield a net benefit of $23,368,572. This resulted in the customers realizing a benefit of $7,754,417 greater than the actual level of off system sales realized during the test year.

Q. **DO THESE CALCULATIONS REFLECT A REASONABLE SHARING OF THE RISKS INCURRED AND THE BENEFITS REALIZED FROM THE OFF SYSTEM SALES TRANSACTIONS?**

A. No. The off system sales activities produced a net loss to KPCo of $7,753,417 while at the same time the off system sales activities produced a net benefit to the KPCo customers of $23,368,572. Thus, KPCo received no benefit from undertaking its system sales activities while at the same time the customers received more than 100% of the test year actual level of activity.

Q. **IS ANY OF THIS DIFFERENCE BETWEEN THE LEVEL OF OFF SYSTEM SALES MARGIN REALIZED BY THE CUSTOMERS AND THE COMPANY'S ACTUAL LEVEL OF OFF SYSTEM SALES MARGIN THE RESULT OF A TIMING DIFFERENCE (THE TWO MONTH LAG BETWEEN EXPENSE AND REVENUE MONTHS)?**

A. Yes, to some extent. But even without the two month lag during the test year, the customers received benefits under the System Sales Clause Tariff that exceeded the Company's total off system sales margins during the test year. Specifically, the test year level of off system sales margin was $15,614,155. By comparison the customers received $24,855,326 in system sales margins through a reduction in base rates and paid $6,188,763 (($15,614,155 - $24,855,326) X 66.97%) through the System Sales Clause Tariff for a net benefit of $18,666,563

($24,855,326 - $6,188,763). This is still 120% ($18,666,563 / $15,614,155) greater than the actual level of off system sales margin realized by the Company.

Q. DOES THIS SUPPORT THE COMPANY'S DECISION TO PROPOSE A CHANGE TO THE SYSTEM SALES CLAUSE TARIFF?

A. Yes. The Company believes that it is not fair, just or reasonable for the customers to realize 150% or even 120% of the actual off system sales margins. Company Witnesses Myers and Roush discuss the proposed changes to the System Sales Clause Tariff.

<u>Net Merger Savings Credit Tariff</u>

Q: IS THE COMPANY PROPOSING TO DISCONTINUE THE NET MERGER SAVINGS CREDIT TARIFF?

A: Yes. As described earlier in my testimony at pages 32-33, the Company is proposing to discontinue Sheet No. 23-1, Net Merger Savings Credit Tariff. Additionally, the Company has removed the Net Merger Savings Credit paragraph on the following electric tariffs: RS, RS-LM-TOD, RS-TOD, SGS, MGS, MGS-TOD, LGS, QP, CIP-TOD, CS-IRP, MW, OL and SL. Sheet No. 23-1 will be reserved for future use.

<u>Environmental Surcharge Tariff</u>

Q: IS THE COMPANY PROPOSING TO CHANGE THE BASE AMOUNT OF ENVIRONMENTAL COSTS REFELECTED IN THE ENVIRONMENTAL SURCHARGE MONTHLY CALCULATIONS?

A: Yes. The Company is proposing to change the base level of monthly environmental costs reflected in the Environmental Surcharge Charge Tariff to the actual monthly levels, adjusted due to the MLR change, during the twelve months ended September 30, 2009. The monthly adjusted amounts, which total $44,185,079, are shown on Exhibit EKW- 10.

XI. CONCLUSION

Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A: Yes.

AFFIDAVIT

Errol K. Wagner, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K. Wagner

Errol K. Wagner

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Errol K. Wagner this 18th day of December 2009.

Judy K Rosquist

Notary Public

My Commission Expires January 23, 2013

Kentucky Power Company
AEP System Pool
Capacity Equalization Settlement
September 30 2009 Actual

Calculation of Member Capacity Surplus / (Deficit) (kw)

Ln No.	Company	Member Primary Capacity (kw)	Member Load Ratio	Primary Capacity Reservation (kw)	Capacity Surplus (Deficit) (kw)
		(1)	(2)	(3)=Total kw*(2)	(4)=(1)-(3)
1	APCo	6,321,000	35.084%	9,199,000	(2,878,000)
2	KPCo	1,453,000	7.069%	1,853,500	(400,500)
3	I&M	5,155,000	17.927%	4,700,500	454,500
4	OPCo	8,450,000	21.326%	5,591,700	2,858,300
5	CSP	4,841,000	18.594%	4,875,300	(34,300)
6	Total	26,220,000	100.000%	26,220,000	0

Calculation of Member Capacity Settlement ($)

Ln No.	Company	Capacity Surplus (Deficit) (kw)	Capacity Rate ($/kw)	Credit (Charge) ($)
		(5)	(6)	(7)
7	APCo	(2,878,000)	$11.98	($34,480,283)
8	KPCo	(400,500)	$11.98	($4,798,246)
9	I&M	454,500	$14.06	$6,390,270
10	OPCo	2,858,300	$11.65	$33,299,195
11	CSP	(34,300)	$11.98	($410,936)
12	Total	0		$0

Exhibit EKW-2

Kentucky Power Company
AEP Pool
Capacity Rate Calculations
I & M and OPCo Surplus Members
September 30 2009 Actual

Ln No.				I&M	OPCo	
		Primary Capacity Investment Rate:				
1		Steam Production Plant as of 12/31/08	($)	$3,927,845,864	$5,181,754,778	
2		Steam Capability as of 12/31/08	(kw)	5,107,000	8,425,000	
3	= (1)/(2)	Average Cost of Investment	($/kw)	$769.11	$615.05	
4		Times Carrying Charge (16.44% / 12 Months)	($/kw/Month)	0.0137	0.0137	
5	= (3)*(4)	Primary Capacity Investment Rate		$10.54	$8.43	
		(Monthly) Fixed Operating Rate:				
6		Steam Plant Operation Expense	($)	$10,985,828	$22,153,380	
7		1/2 Maintenance Expense	($)	$6,975,017	$4,957,458	
8	= (6)+(7)	Subtotal - Fixed Operating Expense	($)	$17,960,845	$27,110,838	
9		Steam Capability	(kw)	5,107,000	8,425,000	
10	= (8)/(9)	Fixed Operating Rate	($/kw)	3.52	3.22	
11	=	**Capacity Rate**	($/kw)	$14.06	$11.65	
		Calculate AEP Pool Average Capacity Rate ($/kw)				
12		Surplus Capacity	(kw)	454,500	2,858,300	
13		Pool's Total Surplus	(kw)	3,312,800	3,312,800	
14		Member's Percent of Pool's Total Surplus	(%)	13.72%	86.28%	
15		Surplus Member's Capacity Rate	($/kw)	$14.06	$11.65	
16		Percentage of Surplus Member's Capacity Rate	($/kw)	1.93	10.05	
17		AEP Pool's Average Capacity Rate	($/kw)			$11.98

Exhibit EKW-3

Kentucky Power Company
Capacity Charge Tariff Revenues
October 1, 2008 through September 31, 2009

Ln No	Month / Year (1)	Total Ky Retail Billed & Accrued kWh (2)	Ky Retail CIP - TOD Billed & Accrued kWh (3)	CIP - TOD Capacity Charge Rate Per kWh (4)	Ky Retail All Other Billed & Accrued kWh (5) = (2) - (3)	All Other Capacity Charge Rate Per kWh -6	Total (7)
1	Oct 08	561,709,447	203,686,379	$0.000508	358,023,068	$0.000824	$398,484
2	Nov 08	633,249,473	202,279,815	$0.000508	430,969,658	$0.000824	$457,877
3	Dec 08	694,085,611	174,589,780	$0.000508	519,495,831	$0.000824	$516,756
4	Jan 09	756,126,820	186,847,268	$0.000508	569,279,552	$0.000824	$564,005
5	Feb 09	629,091,345	162,934,835	$0.000508	466,156,510	$0.000824	$466,884
6	Mar 09	637,687,025	202,705,909	$0.000508	434,981,116	$0.000824	$461,399
7	Apr 09	520,481,012	194,776,541	$0.000508	325,704,471	$0.000824	$367,327
8	May 09	527,644,029	190,157,896	$0.000508	337,486,133	$0.000824	$374,689
9	Jun 09	566,828,292	188,801,051	$0.000508	378,027,241	$0.000824	$407,405
10	Jul 09	536,296,449	178,234,197	$0.000508	358,062,252	$0.000824	$385,586
11	Aug 09	586,860,703	185,623,219	$0.000508	401,237,484	$0.000824	$424,916
12	Sep 09	498,816,293	173,431,495	$0.000508	325,384,798	$0.000824	$356,220
13	Total	7,148,876,499	2,244,068,385		4,904,808,114		$5,181,547

Kentucky Power Company
Analysis of
Over/(Under) Recovery of Fuel
Test Period Ended 9/30/09

Ln No (1)	month/year (2)	Generation Month KWH Sales (3)	Billed Olive Hill Vanceburg Sales (4)	Juris. KWH Sales (C3-C4) (5)	Total Company Fuel Cost (6)	Juris. Fuel Cost (C5*C10) (7)	Deferred Fuel (8)	Juris. Total Fuel Cost (C7+C8) (9)	Cents Per kWh (C6/C3) (10)	Billed and Accrued KWH (11)	Base Fuel (12)	F.A.C. (13)	Base Fuel Revenue (C11*C12) (14)	F.A.C. Revenue (C11*C13) (15)	Total Fuel Revenue (C14+C15) (16)	Over(Under) Recovery of Fuel (C16-C9) (17)
1	Aug 08	586,047,000		586,047,000	$24,038,623	$24,038,623		$24,038,623	0.04102		0.0212	0.01978				
2	Sep 08	538,404,000		538,404,000	$19,946,353	$19,946,353		$19,946,353	0.03705		0.0212	0.01581				
3	Oct 08	556,713,000	7,038,193	549,674,807	$21,606,348	$21,333,192	$3,351,659	$24,684,851	0.03881	561,709,447	0.0212	0.01757	$11,930,709	$11,110,613	$23,041,322	($1,643,529)
4	Nov 08	637,522,000	8,286,090	629,235,910	$21,140,584	$20,865,813	$2,016,766	$22,882,579	0.03316	633,249,473	0.0212	0.01192	$13,450,219	$10,011,674	$23,461,893	$579,314
5	Dec 08	703,013,000	9,669,878	693,343,122	$17,915,317	$17,668,893	$4,997,695	$22,666,588	0.02548	694,085,611	0.0212	0.00424	$14,742,378	$12,195,084	$26,937,462	$4,270,874
6	Jan 09	769,140,000	11,011,292	758,128,708	$19,517,723	$19,238,300	($564,437)	$18,673,863	0.02538	756,126,820	0.0212	0.00414	$16,060,134	$9,013,032	$25,073,166	$6,399,303
7	Feb 09	634,479,000	8,561,957	625,917,043	$19,475,274	$19,212,466	($3,327,973)	$15,884,493	0.03069	629,091,345	0.0212	0.00945	$13,361,900	$2,667,347	$16,029,247	$144,754
8	Mar 09	614,688,000	7,729,133	606,958,867	$17,515,169	$17,294,932	($392,596)	$16,902,336	0.02849	637,687,025	0.0212	0.00725	$13,544,472	$2,640,024	$16,184,496	($717,840)
9	Apr 09	525,508,000	6,581,317	518,926,683	$15,357,750	$15,165,414	$241,965	$15,407,379	0.02922	520,481,012	0.0212	0.00798	$11,055,017	$4,918,546	$15,973,563	$566,184
10	May 09	523,604,000	6,393,475	517,210,525	$15,449,602	$15,260,954	$1,288,235	$16,549,189	0.02951	527,644,029	0.0212	0.00827	$11,207,159	$3,825,419	$15,032,578	($1,516,611)
11	Jun 09	550,533,000	7,370,532	543,162,468	$14,336,479	$14,144,542	$3,313,979	$17,458,521	0.02604	566,828,292	0.0212	0.00480	$12,039,433	$4,523,290	$16,562,723	($895,798)
12	Jul 09	556,874,000	7,444,053	549,429,947	$14,700,143	$14,503,638	$3,522,408	$18,026,046	0.02640	536,296,449	0.02840	(0.00200)	$15,230,819	$4,435,172	$19,665,991	$1,639,945
13	Aug 09	583,830,000	8,060,952	575,769,048	$14,351,281	$14,153,133	$2,917,142	$17,070,275	0.02458	586,860,703	0.02840	(0.00382)	$16,666,844	$2,816,931	$19,483,775	$2,413,500
14	Sep 09	518,820,000	6,702,337	512,117,663	$12,920,429	$12,753,517	$666,090	$13,419,607	0.02490	498,816,293	0.02840	(0.00350)	$14,166,383	($997,633)	$13,168,750	($250,857)
15	Aug-Sep Total	7,174,724,000	94,849,209	7,079,874,791	$204,286,099	$201,594,794	$18,030,933	$219,625,727		7,148,876,499			$163,455,467	$67,159,499	$230,614,966	$10,989,239

Exhibit EKW-4

P.S.C. ELECTRIC NO. 9
CANCELS P.S.C. ELECTRIC NO. 8 (T)

Cancels and Supersedes all Previous Schedules

KENTUCKY POWER COMPANY

SCHEDULE OF TARIFFS, TERMS AND CONDITIONS OF SERVICE GOVERNING SALE OF ELECTRICITY

In the Kentucky territory served
By Kentucky Power Company
As stated on Sheet No. 1

Issued by
Errol K. Wagner, Director Regulatory Services
Frankfort, Kentucky

Issued: December 29, 2009 Effective: January 29, 2010

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KENTUCKY POWER COMPANY

Original Sheet No. 1-2
Canceling ________ Sheet No. 1-2

P.S.C. ELECTRIC NO. 9

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Tariff X.X.	Reserved for Future Use	23-1	
Rider E.C.S.	Emergency Curtailable Service Rider (Discontinued)	24-1 thru 24-3	(D)
Rider E.C.S. – C. & E.	Emergency Curtailable Service – Capacity & Energy	24-1 thru 24-6	(N)
Rider E.P.C.S.	Energy Price Curtailable Service Rider	25-1 thru 25-3	
Tariff N.U.G.	Non-Utility Generator	26-1 thru 26-3	
Tariff N.M.S.	Net Metering Service	27-1 thru 27-22	
Tariff C.C.	Capacity Charge	28-1	
Tariff E.S.	Environmental Surcharge	29-1 thru 29-5	
Tariff R.T.P.	Experimental Real-Time Pricing	30-1 thru 30-4	
Rider G.P.O.	Green Pricing Option Rider	31-1	
Rider A.F.S.	Alternate Feed Service Rider	32-1 thru 32-4	(N)
Tariff U.G.R.T.	Utility Gross Receipts Tax (School Tax)	33-1	(N)
Tariff K.S.T.	Kentucky Sales Tax	34-1	(N)
Tariff T.A.	Transmission Adjustment	35-1 thru 35-2	(N)

THE ABOVE TARIFFS ARE APPLICABLE TO THE ENTIRE TERRITORY
SERVED BY KENTUCKY POWER COMPANY AS ON FILE WITH THE PUBLIC SERVICE COMMISSION
AT BOYD, BREATHITT, CARTER, CLAY, ELLIOTT, FLOYD, GREENUP, JOHNSON, KNOTT, LAWRENCE, LESLIE,
LETCHER, LEWIS, MAGOFFIN, MARTIN, MORGAN, OWSLEY, PERRY, PIKE AND ROWAN COUNTIES.

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459

TERMS AND CONDITIONS OF SERVICE

1. **APPLICATION.**

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. (T)

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. **INSPECTION.**

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may refuse to connect to the customer's system if such connection is deemed unsafe by the Company.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. **SERVICE CONNECTIONS.**

Service connections will be provided in accordance with 807 KAR 5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

(Cont'd on Sheet No. 2-2)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. **DEPOSITS.**

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained during the entire time that the account remains active.

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which shall be considered by the Company cumulatively.

1. Satisfactory payment history.
2. Statement from another utility showing satisfactory payment history.
3. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit.
4. Providing evidence of other collateral acceptable to Company, such as Surety Bond.
5. Checkless Payment Plan (CPP)

C. Method of Determination

1. Calculated Deposits

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.

b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill. (T)

(Cont'd on Sheet No. 2-3)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. **DEPOSITS, (Cont'd.)**

D. Additional or Supplemental Deposit Requirement
If a deposit has been waived or returned and the Customer fails to maintain a satisfactory payment record the Customer may be required to pay an additional or supplemental deposit. Except for residential customers, an additional or supplemental deposit may be required if the Customer's credit rating falls to a C level or below as reported by a national credit reporting agency. Factors to be considered when evaluating if a Customer fails to maintain a satisfactory payment record include, but are not limited to; integrity of past payments (returned checks), account credit activity, age of arrearage and frequency of late payments, all during the most recent six month period. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed on the bill an additional or supplemental deposit will be charged to the account the next time the account is billed. If a change in usage or classification of service has occurred, the Customer may be required to pay an additional deposit up to 2/12 of the annual usage. (T)

E. Recalculation of Customers Deposit
When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment by check or credit to the Customer's bill. No refund will be made if the Customer's bill is delinquent at the time of the recalculation.

5. **PAYMENTS.**

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan

Residential Customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customers' estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence in any month.

In the last month of the plan, if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

B. Average Monthly Payment Plan (AMP)

The Average Monthly Payment Plan (AMP Plan) is available to the following applicable tariffs; R.S.; R.S.-L.M-T.O.D.; Experimental R.S.-T.O.D 2.; S.G.S., and S.G.S.-T.O.D. When mutually agreeable the AMP Plan may be offered by the Company to Customers serviced under other tariffs. (T)

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

(Cont'd on Sheet No. 2-4)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

B. AVERAGE MONTHLY PAYMENT PLAN (AMP) (CONT'D).

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve consecutive billings months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. ALL PAYMENTS.

All bills are payable at the business offices or authorized collection agencies of the Company within the time limits specified in the tariff. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

The tariffs of the Company are net if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. To discourage delinquency and encourage prompt payment within the specified time limit, certain tariffs contain a delayed payment charge, which may be added in accordance with the tariff under which service is provided. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding 6 months.

6. UNDERGROUND SERVICE.

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer, as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

7. COMPANY'S LIABILITY.

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or causes to be avoided. Force Majeure events includes act of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

(Cont'd on Sheet No. 2-5)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

7. COMPANY'S LIABILITY (Cont'd)

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are (T) connected to the Company's facilities. The metering device is the property of the Company; however, the meter base, connection and grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, (T) without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The (T) Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

8. CUSTOMER'S LIABILITY.

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking of seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus, which shall be the property of the Company.

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause.

9. EXTENSION OF SERVICE.

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

(Cont'd on Sheet No. 2-6)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

9. **EXTENSION OF SERVICE (Cont'd)**

For service to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to serve the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

1. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.

2. The annual energy costs based on the latest available production costs related to the Customer's estimated annual energy use requirements.

3. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as described herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer, exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in revenue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the Company the estimated total installed cost of the required new facilities which advance could be refunded over a five-year period under certain conditions. Over the five year period the Customer's electric bill would be credited each month up to the amount of 1/60th of the total amount advanced. Such credit shall be applied only to that portion of the Customer's bill, which exceeds a specified minimum. The specified minimum before refund shall be established as the greater of: (1) the minimum as described under the applicable tariff or (2) the amount representing 1/12th of the calculated annual cost to serve as described herein. In the event the Customer's monthly bill in any month does not exceed such minimum by an amount equal to 1/60th of the amount advanced, the difference between 1/60th of the amount advanced and the amount, if any, actually credited to the Customer's bill shall be designated as "accrued credit" and applied to future monthly bills over the balance of the 5 year period as credit where such monthly bills exceed the established minimum by more than 1/60th of the amount advanced.

10. **EXTENSION OF SERVICE TO MOBILE HOME.**

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

(Cont'd on Sheet No. 2-7)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

11. **LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT.**

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

12. **BILLING FORM.**

Pursuant to 807 KAR 5:006, Section 6(3) copies of the billing forms used by the Company are shown on Sheet Nos. 2-11, 2-12 and 2-13 and 2-14. (T)

13. **RATE SCHEDULE SELECTION.**

The Company will explain to the Customer, at the beginning of service or upon request the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedule.

14. **MONITORING USAGE.**

At least once annually the Company will monitor the usage of each customer according to the following procedure:

1. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
2. If the monthly usage for the two periods are substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
3. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
4. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the Company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
5. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
6. The Company will notify the customers of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 10(4) and (5).

In addition to the annual monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry.

(Cont'd on Sheet No. 2-8)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

15. **USE OF ENERGY BY CUSTOMER.**

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load.

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs, which specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

16. **RESIDENTIAL SERVICE.**

Individual residences shall be served individually with single-phase service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

(Cont'd on Sheet No. 2-9)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

17. **DENIAL OR DISCONTINUANCE OF SERVICE.**

The Company reserves the right to refuse to serve any applicant for service or to discontinue to serve any Customer if the applicant or Customer is indebted to the Company for any service theretofore rendered at any location; provided however, the Customer shall be notified in writing in accordance with 807 KAR 5:006, Section 14, before disconnection of service.

The Company reserves the right to discontinue to serve any Customer for failure to provide and maintain adequate security for the payment of bills as requested by the Company, for failure to comply with these terms and conditions or to prevent fraud upon the Company.

Any discontinuance of service shall not terminate the contract for electric service between the Company and the Customer nor shall it abrogate any minimum charge, which may be effective.

18. **EMPLOYEES' DISCOUNT.**

Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee.

19. **SPECIAL CHARGES.**

A. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 8 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 15 shall be exempt from the reconnect charges.

1. Reconnect for nonpayment during regular hours..........................$ ~~12.94~~ *$ 40.00* (I)
2. Reconnect for nonpayment when work continues into overtime at the end of the day (No "Call Out" required).......................... $ ~~17.26~~ *$ 47.00* (I)
3. Reconnect for nonpayment when a "Call Out" is required (A "Call Out" is when an employee must be called in to work on an overtime basis to make the reconnect trip)........................ $ ~~35.95~~ *$ 83.00* (I)
4. Reconnect for nonpayment when double time is required (Sunday and Holiday).. $ ~~44.58~~ *$108.00* (I)
5. Termination or field trip.. $ ~~8.63~~ *$ 24.00* (I)

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

The reconnection charge for all Customers where service has been disconnected at the request of the customer and the same customer requests that the service be reconnected within a period of twelve (12) months from the date that service was disconnected shall be $ *40.00*. Such reconnections shall occur only during regular hours. (N)

(Cont'd on Sheet No. 2-10)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

19. **SPECIAL CHARGES (Cont'd).**

B. Returned Check Charge

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $7.00 to cover the handling costs.

C. Meter Test Charge

Where test of a meter is made upon written request of the Customer pursuant to 807 KAR 5:006, Section 18, the Customer will be charged ~~$14.38~~ *$68.00* if such test shows that the meter was not more than two percent (2%) fast. (I)

D. Work Performed on Company's Facilities at Customer's Request

Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities, shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

(Cont'd on Sheet No. 2-11)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Residential and Small Commercial Bill Form – Page 1

KENTUCKY POWER
A unit of American Electric Power

Total Amount Due $ XX.XX
Due Nov 17, Add X.XX after Dec 02

Amount Enclosed

Send Inquiries To:
PO BOX 24401
CANTON, OH 44701-4401
R K-746886894

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
P.O. BOX 24417
CANTON OHIO 44701-4417

KPCO Consumer
123 ANY ADDRESS
AEP CITY, KY 99999-9999

000006490000006490000000000003999999999220214030181038O5

Please tear on dotted line — Account Number 039-999-999-1-2 — Return top portion with your payment

SERVICE AT:
KPCO Consumer
123 ANY ADDRESS
AEP CITY, KY 99999-9999

Questions About Bill or Service, Call; 1-800-572-1113
Pay by Phone 1-877-306-9280

Account Number 039-999-999-9-9

Bill Date 10/30/09
Page 1 of 2 010

	Account Balance		Amount Due
PREVIOUS CHARGES			
Total Amount Due at Last Billing	$ XX.XX		
Payment 10/12/09 - Thank You	XX.XX CR		
Previous Balance	$ XX.XX		$ XX.XX
CURRENT KPCO CHARGES (1-800-572-1113):			
10/30/09 Tariff 015 - RESIDENTIAL SERVICE			
Rate Billing	$ XX.XX		
Fuel Adj @ 0.0XXXXXX Per KWH	X.XX		
DSM Adj @ 0.0XXXXXX Per KWH	.XX		
Residential HEAP @ $0.10	.XX		
Capacity Charge @ 0.0XXXXXX Per KWH	.XX		
Environmental Adj X.XXXXXX%	.XX		
Transmission Adj X.XXXXXX%	.XX CR		
School Tax	.XX		
State Sales Tax	.XX		
Green Pricing Option 2 BlocksTax	X.XX		
Current Electric Due	$ XX.XX		$ XX.XX

Total Amount Due $ XX.XX
Due Nov 17, Add X.XX after Dec 02

$x.xx is your average daily cost for current electric service

USAGE:

Meter Number	Service Period From	To	Prev	Meter Reading CD	Pres	CD	Multiplier	Metered Usage
99999999	10/1/2009	10/30/2009	29466	R	29748	R	1.0000	282

CD - Read Code: A= Actual Reading — 29 Billing Days — Next Reading Date 12/02/09

KENTUCKY POWER
A unit of American Electric Power

Rates Available on Request

See other side for

(N)

(T)

(Cont'd on Sheet No. 2-12)

KENTUCKY POWER COMPANY

Original Sheet No. 2-12
Canceling ______ Sheet No. 2-12

P.S.C. ELECTRIC NO. 9

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Residential and Small Commercial Bill Form – Page 2

Send Inquiries To:

PO BOX 24401
CANTON, OH 44701-4401
R-K-740865684

Account Number
039-999-999-9-9

Page 2 of 2

USAGE:

Month	Usage	Month	Usage	Month	Usage	Month	Usage	Month	Usage	Month	Usage
Nov 08	711	Jan 09	1,448	Mar 09	1,046	May 09	846	July 09	1,174	Sept 09	788
Dec 08	955	Feb 09	1,478	Apr 09	954	Jun 09	1,155	Aug 09	718	Oct 09	827

Average Monthly Usage: 493 KWH Total Usage (Past 12 Months): 5921 KWH

KPCO MESSAGES:

You may view detail rate information online at http://www.aepcustomer.com/tariffs/default.htm.

Visit us at www.KentuckyPower.com

AEP KENTUCKY POWER
A unit of American Electric Power

Rates Available on Request

See other side for important information

(Cont'd on Sheet No. 2-13)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, , KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

KENTUCKY POWER COMPANY

Original Sheet No. 2-13
Canceling ______ Sheet No. 2-13

P.S.C. ELECTRIC NO. 9

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Large Commercial and Industrial Bill Form – Page 1

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquiries To:

PO BOX 24401
CANTON, OH 44701-4401
R K-740000084

Total Amount Due $ XXXX.XX
Due Dec 02, Add $XXX.XX After This Date

Amount Enclosed

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
P.O. BOX 24417
CANTON OHIO 44701-4417

KPCO LARGE POWER
123 ANY ADDRESS
AEP CITY, KY 99999-9999

000006490000006490000000000039999999992202140301810380 5

Please tear on dotted line — Account Number 039-999-999-1-2 — Return top portion with your payment

SERVICE AT:

KPCO LARGE POWER
123 ANY ADDRESS
AEP CITY, KY 99999-9999

Questions About Bill or Service, Call: 1-800-572-1109
Pay by Phone 1-877-306-9999

Account Number 039-999-999-9-9

Bill Date 11/12/09
Page 1 of 2 010

		Account Balance		Amount Due
PREVIOUS CHARGES				
Total Amount Due at Last Billing	$	XXXX.XX		
Payment 10/30/09 - Thank You		XXXX.XX CR		
Previous Balance	$	XX	$	XXXX.XX
CURRENT KPCO CHARGES (1-888-710-4237:				
11/12/09 Tariff 244 - LARGE GENERAL SERVICE				
Rate Billing	$	XXXX.XX		
Fuel Adj @ 0.0XXXXXX Per KWH		XXX.XX		
Capacity Charge @ 0.0XXXXXX Per KWH		XX.XX		
Environmental Adj X.XXXXXXX%		XX.XX		
Transmission Adj X.XXXXXXX%		XX.XX CR		
School Tax		XXX.XX		
State Sales Tax		XXX.XX		
Green Pricing Option 2 BlocksTax		X.XX		
Current Electric Due	$	XXXX.XX	$	XXXX.XX

(N)

(T)

Total Amount Due $ XXXX.XX
Due Dec 02, Add $XXX.XX After This Date

Average energy cost per KWH = $x.xx

USAGE:

Meter Number	Service Period From	To	Meter Reading Prev	CD	Pres	CD	Multiplier	Metered Usage
99999999	10/14/2009	11/12/2009	XXXXX	A	XXXXX	A	XXX.XXXX	XXXXX KWH
99999999	10/14/2009	11/12/2009		A	XXXXX	A	XXX.XXXX	XXX.XX KW
99999999	10/14/2009	11/12/2009	XXXXX	A	XXXXX	A	XXX.XXXX	XXXXX KVARH

CD - Read Code: A= Actual Reading — 32 Billing Days — Next Reading Date 12/16/09

AEP KENTUCKY POWER
A unit of American Electric Power

Rates Available on Request

See other side for important information

(Cont'd on Sheet No. 2-14)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

KENTUCKY POWER COMPANY

Original Sheet No. 2-14
Canceling _______ Sheet No. 2-14

P.S.C. ELECTRIC NO. 9

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Large Commercial and Industrial Bill Form – Page 2

Account Number
039-999-999-9-9

Page 2 of 2

Send Inquiries To:

PO BOX 24401
CANTON, OH 44701-4401
039-999-999-9-9 CYC 01

Month Usage	Month Usage	Month Usage	Month Usage	Month Usage	Month Usage
Nov 08 17,500	Jan 09 30,100	Mar 09 21,700	May 09 22,400	July 09 32,200	Sept 09 43,400
Dec 08 22,400	Feb 09 23,800	Apr 09 22,400	Jun 09 25,900	Aug 09 30,100	Oct 09 41,300

Average Monthly Usage: 2766 KWH Total Usage (Past 12 Months): 333200 KWH

ADJUSTED USAGE

Metered Usage	Power Factor	Power Factor Constant	Comp Meter Multiplier	Billing Usage
				XXXXX KWH
				XXX XX KW
				XXXXX KVARH

Contract Capacity = XXX.X High Prev Demand = On-Pk
Off-Pk

KPCo MESSAGES

Visit us at www.KentuckyPower.com

AEP KENTUCKY POWER
A unit of American Electric Power

Rates Available on Request

See other side for important information

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

CAPACITY AND ENERGY CONTROL PROGRAM

The Company's Capacity and Energy Control Program consists of:

I. Procedures During Abnormal System Frequency

II. Capacity Deficiency Program

III. Energy Emergency Control Program

A copy of the Company's Emergency Operating Plan was filed with the Kentucky Public Service Commission on May 1, 2008 in Administrative Case No. 353 in compliance with the Commission's Order dated January 20, 1995. (T)

I. PROCEDURES DURING ABNORMAL SYSTEM FREQUENCY

A. INTRODUCTION

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP program, which is in accordance with ECAR Document 3, is noted below.

B. PROCEDURES AEP/PJM

1. From 59.8 – 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. For rapid frequency decline, only that capacity on-line and automatically responsive to frequency (spinning reserve), and such items as interconnection assistance and load reductions by automatic means are of assistance in arresting the decline in frequency.

   If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, should invoke non-automatic procedures involving operating and emergency reserves. These efforts should continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies.

2. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load

3. At 59.5 Hz automatically shed 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

4. At 59.4 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

5. At 59.3 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

6. At 59.1 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

7. At 59.0 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

8. At 58.9 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

9. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.

10. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

If at any time in the above procedure the decline in area frequency is arrested below 59.0 Hz, that part of the System in the low frequency area should shed an additional 10% of its initial load. If, after five minutes, this action has not returned the area frequency to 59.0 Hz or above, that part of the System shall shed an additional 10% of its remaining load and continue to repeat in five-minute intervals until 59.0 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units. (Cont'd on Sheet No. 3-2)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

II. CAPACITY DEFICIENCY PROGRAM

A. PURPOSE

To provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP)East/PJM Eastern System in the event of a capacity deficiency.

B. CRITERIA

The goals of AEP areis to safely and reliably operate the interconnected network in order to avoid widespread system outages as a consequence of a major disturbance. Precautionary procedures including maintaining Daily Operating Reserves, as specified in ECAR document 2, and PJM Manual M13, will assist in avoiding serious emergency conditions such as system separation and operation at abnormal frequency. However, adequate Daily Operating Reserves cannot always be maintained, so the use of additional emergency measures may be required. A Capacity Deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

C. AEP EAST/PJM PROCEDURES

(note: the following section contains excerpts from PJM Manual – M13)

OVERVIEW

PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM Members as necessary to manage, allocate, or alleviate an emergency.

- *PJM RTO Reserve Deficiencies* — If PJM determines that PJM-scheduled resources available for an Operating Day in combination with Capacity Resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the PJM RTO, PJM performs the following actions:
- Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.
- Purchases capacity or energy from resources outside the Control Area. PJM uses its best efforts to purchase capacity or energy at the lowest prices available at the time such capacity or energy is needed. The price of any such capacity or energy is not considered in determining Locational Marginal Prices in the PJM Energy Market. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for Operating Agreement Accounting (M-28)

The AEP System Control Center will be referred to as SCC and the AEP Production Optimization Group will be referred to as POG.

CAPACITY SHORTAGES

PJM is responsible for monitoring the operation of the PJM RTO, for declaring the existence of an Emergency, and for directing the operations of the PJM Member as necessary to manage, alleviate, or end an Emergency. PJM also is responsible for transferring energy on the PJM Members behalf to meet an Emergency. PJM is also responsible for agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an Emergency.
Exhibit 1 illustrates that there are three general levels of emergency actions for capacity shortages:

- alerts
- warnings
- actions

ALERTS

The intent of the alerts is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All alerts and cancellation thereof are broadcast on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.
Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages.

(Cont'd on Sheet No.3-3)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP East/PJM Procedures (cont'd)

Alerts(Cont'd)

Maximum Emergency Generation Alert
The purpose of the Maximum Emergency Generation Alert is to provide an early alert that system conditions may require the use of the PJM emergency procedures. It is implemented when Maximum Emergency Generation is called into the operating capacity.

Primary Reserve Alert
The purpose of the Primary Reserve Alert is to alert members of the anticipated shortage of operating reserve capacity for a future critical period. It is implemented when estimated operating reserve capacity is less than the forecast primary reserve requirement.

Voltage Reduction Alert
The purpose of the Voltage Reduction Alert is to alert members that a voltage reduction may be required during a future critical period. It is implemented when the estimated operating reserve capacity is less than the forecast spinning reserve requirement.

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Warnings

Warnings are issued during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All warnings and cancellations are broadcasted on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.

Primary Reserve Warning
The purpose of the Primary Reserve Warning is to warn members that the available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve capacity is less than the primary reserve requirement, but greater than the spinning reserve requirement, after all available secondary reserve capacity (except restricted maximum emergency capacity) is brought to a primary reserve status and emergency operating capacity is scheduled from adjacent systems.

Voltage Reduction Warning & Reduction of Non-Critical Plant Load
The purpose of the Voltage Reduction Warning & Reduction of Non-Critical Plant Load is to warn members that the available spinning reserve is less than the Spinning Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required. It is implemented when the available spinning reserve capacity is less than the spinning reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a spinning reserve status and emergency operating capacity is scheduled from adjacent systems.

Manual Load Dump Warning
The purpose of the Manual Load Dump Warning is to warn members of the increasingly critical condition of present operations that may require manually dumping load. It is issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve. The amount of load and the location of areas(s) are specified.

Actions

The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- Loading generation that is restricted for reasons other than cost
- Recalling non-capacity backed off-system sales
- Purchasing emergency energy from participants / surrounding pools
- Load relief measures

(Cont'd on Sheet No. 3-4)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP East/PJM Procedures (Cont'd)

Actions (Cont'd)

The procedures to be used under these circumstances are described in the general order in which they are applied. Due to system conditions and the time required to obtain results, PJM dispatcher may find it necessary to vary the order of application to achieve the best overall system reliability. Issuance and cancellation of emergency procedures are broadcast over the "ALL-CALL" and posted to selected PJM web sites. Only affected systems take action. PJM dispatcher broadcasts the current and projected PJM RTO status periodically using the "ALL-CALL" during the extent of the implementation of the emergency procedures.

Maximum Emergency Generation
The purpose of the Maximum Emergency Generation is to increase the PJM RTO generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost level.

Load Management Curtailments (ALM)

Steps 1 and 2 (PJM Control)
The purpose of the Load Management Curtailments, Steps 1 and 2, is to provide additional load relief by using PJM controllable load management programs. Steps 1 and 2 are differentiated only by the expected time to implement. Load relief is required after initiating Maximum Emergency Generation.

Step 1: Short Time Frame to Implement (1 Hour or Less)
- PJM dispatcher requests members to implement Load Management Curtailment, Step 1.

Step 2: Long Time Frame To Implement (Greater Than 1 Hour)
- PJM dispatcher requests members to implement Load Management Curtailment, Step 2.

Steps 3 and 4 (SCC Control)
The purpose of the Local Control Center Programs of Load Management Curtailments, Steps 3 and 4, is to provide additional load relief by requesting use of Local Control Center load management programs.

Load Reduction Program
The purpose of the Load Reduction Action is to request end-use customers to reduce load during emergency conditions.

Voltage Reduction
The purpose of Voltage Reduction during capacity deficient conditions is to reduce load to provide a sufficient amount of reserve to maintain tie flow schedules and preserve limited energy sources. A curtailment of non-essential building load is implemented prior to or at this same time as a Voltage Reduction Action. It is implemented when load relief is still needed to maintain tie schedules.

Note: Voltage reductions can also be implemented to increase transmission system voltage.

Note: Curtailment of non-essential building load may be implemented prior to, but not later than, the same time as a voltage reduction.

Curtailment of Non-Essential Building Load
The purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief, to be expedited prior to, but no later than the same time as a voltage reduction.

(Cont'd on Sheet No. 3-5)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP East/PJM Procedures (cont'd)

Actions

Voluntary Customer Load Curtailment
The purpose of the Voluntary Customer Load Curtailment (VCLC) is to provide further load relief. It is implemented when the estimated peak load minus the relief expected from curtailment of non-essential building load and a 2.5% - 5% voltage reduction is greater than operating capacity.

PJM/SCC – Public Appeal to conserve electricity usage

Manual Load Dump
The purpose of the Manual Load Dump is to provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions. It is implemented when the PJM RTO cannot provide adequate capacity to meet the PJM RTO's load or critically overloaded transmission lines or equipment cannot be relieved in any other way and/or low frequency operation occurs in the PJM RTO, parts of the PJM RTO, or PJM RTO and adjacent Control Areas that may be separated as an island.

Addendum to Manual Load Dump Procedures

AEP understands that PJM intends to implement these curtailment protocols consistent with the agreements that PJM entered into in Kentucky and Virginia, in Stipulations approved by the Kentucky Public Service Commission and Virginia State Corporation Commission (with modifications) in Case No. 2002-00475 and Case No. PUE-2000-00550, respectively.

Capacity Deficiency Summary

A summary of the emergency alerts, warning and actions, together with the typical sequence and the method of communication, are presented in the following Table III-2 on Tariff Sheet No. 3-6.

(Cont'd on Sheet No. 3-6)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

		Communications	Description	
Alert	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG review scheduled or actual maintenance affecting capacity or critical transmission to determine if it can be deferred or cancelled	EEA 1
	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	(Same as above)	
	Voltage Reduction	PJM-SCC via All-Call SCC-TDC	SCC/TDC to identify stations for Voltage Reduction	
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	
Warning	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted.	
	Voltage Reduction & Reduction of Non-Critical Plant Load	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC to inform TDC to man Voltage Reduction Stations & prepare for Voltage Reduction	POG to reduce plant load. (See Table III-4)
	Manual Load Dump	PJM-SCC via All-Call SCC-- POG-Environmental Services SCC-TDC-DDC	Lifting of Environmental Restrictions (See Table III-5)	Manual & Automatic Load Shedding
		Make preparations for a Public Appeal if one becomes necessary.	a. Obtain permission to exceed opacity limits b. Obtain permission to exceed heat input limits c. Obtain permission to exceed river temperature limits	SCC/TDC will review local computer procedures and man manual load shedding stations
Action	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call	Supplemental Oil & Gas Firing; Operate Generator Peakers; Emergency Hydro; Extra Load Capability	See Table III-3
	Load Management Curtailment (ALM)	PJM-SCC via All-Call SCC - POG	Step 3 – 1267 Mws – 1 hr, 249 Mws – 2 hr	EEA 2 (DOE Report)
	Load Reduction Program	PJM-SCC via All-Call	Not Applicable	
	Voltage Reduction	PJM-SCC via All-Call SCC –TDC & SCC - POG	Initiate Voltage Reduction - AEP/PJM – 64 Mws	
	Curtailment of Non-Essential Building Load	PJM-POG via All-Call PJM-SCC via All-Call SCC- Building Services	Initiate curtailment of AEP building load – 4.4 Mws	Issued approx. same time as Voltage Reduction
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	EEA 3 (DOE Report)
	Public Appeal (may be issued at any stage of the Action items)	SCC – Corporate Communications	a. Radio and TV alert to general public	2% of AEP Internal Load
		SCC – Customer Services SCC - POG	b. Call to Industrial and Commercial Customers	1276 Mws - 1 hr + 320 Mws - 2 hr
		SCC - TDC	c. Municipal and REMC Customers	7% of Cust. Load
	Manual Load Dump	PJM-SCC via All-Call SCC-POG-Environmental Services SCC-TDC-DDC	PJM Allocation based on deficient zones	
			a. Lift Environmental Restrictions on units	(regains curtailed generation)
			b. Selected distribution customers (manual load curtailment)	Execute MLD

(Cont'd on Sheet No. 3-7)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C)

1. Alert 1 - All available resources in use.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 - Load management procedures in effect.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
   - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
     - Voltage reduction
     - Emergency Curtailable Service
     - Public appeals to reduce demand
     - Interruption of non-firm end use loads in accordance with applicable contracts, for emergency, not economic reasons
     - Demand-side management
     - Utility load conservation measures
   - During Alert 2, The Reliability Coordinators, Control Areas, and Energy Deficient Entities and AEP have the following responsibilities:

     2.1 Notifying other Control Areas and Market Participants.

     2.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated.

     2.3 Share information on resource availability.

     2.4 Evaluating and mitigating transmission limitations.
     2.4.1 Notification of ATC adjustments.
     2.4.2 Availability of generation redispatch options.
     2.4.3 Evaluating impact of current Transmission Loading Relief events.
     2.4.4 Initiating inquiries on reevaluating Operating Security Limits.

     2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

     2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of available resources. This includes but is not limited to:

     2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

     2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

(Cont'd on Sheet No. 3-8)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C) (Cont'd)

2.6.3 Non-firm sales recalled and contractually interruptible loads and DSM curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity AEP is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 - Firm load interruption imminent or in progress.

Circumstances:

- Control Area or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2.

3.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated.

3.3 Use of Transmission short-time limits.

3.4 Reevaluating and revising Operating Security Limits.

3.4.1 AEP Energy Deficient Entity obligations. The deficient Control Area or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use his best efforts to ensure that revising Operating Security Limits would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency Operating Security Limits, the Control Area Coordinator Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the Alert.

3.5.1 Notification of other parties. Notifications will be made via Oasis and the RCIS.

3.6 Reporting. Any time an Alert 3 is declared, the Control Area Coordinator Energy Deficient Entity shall complete the report listed in NERC Appendix 9B, Section C and submit this report to its respective Reliability Coordinator within two business days of downgrading or termination of the Alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The Reliability Coordinator shall present this report to the appropriate NERC Sub-committee Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of his Reliability Coordinator that the EEA be terminated.

4.1 Notification.

(Cont'd on Sheet No. 3-9)

CAPACITY AND ENERGY CONTROL PROGRAM

III. ENERGY EMERGENCY CONTROL PROGRAM

A. INTRODUCTION

The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

B. PROCEDURES

In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction.

A. To be initiated when system fuel supplies are decreased to 70% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Optimize the use of non-coal-fired generation to the extent possible.

2. For individual plants significantly under 750% of normal minimum target days' supply, review the prudence of modifying economic dispatching procedures to conserve coal.

3. If necessary discontinue all economy sales to neighboring utilities.

4. Curtail the use of energy in company offices, plants, etc., over and above the reductions already achieved by current in-house conservation measures.

B. To be initiated when system fuel supplies are decreased to 60% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Substitute the use of oil for coal, as permitted by plant design, oil storage facilities, and oil availability.

2. Discontinue all economy and short-term sales to neighboring utilities.

3. Limit emergency deliveries to neighboring utilities to situations where regular customers of such utilities would otherwise be dropped or where the receiving utility agrees to return like quantities of energy within 14 days.

4. Curtail electric energy consumption by customers on Interruptible contracts to a maximum of 132 hours of use at contract demand per week.

5. Purchase energy from neighboring systems to the extent practicable.

6. Purchase energy from industrial customers with generation facilities to the extent practicable.

7. Through the use of news media and direct consumer contact, appeal to all customers (retail as well as wholesale) to reduce their nonessential use of electric energy as much as possible, in any case by at least 25%.

8. Reduce voltage around the clock to the extent feasible.

9. The Company will advise customers of the nature of the mandatory program to be introduced in C below, through direct contact and mass media, and establish an effective means of answering specific customer inquiries concerning the impact of the mandatory program on electricity availability.

(Cont'd on Sheet No. 3-10)

CAPACITY AND ENERGY CONTROL PROGRAM(Cont'd)

III. ENERGY EMERGENCY CONTROL PROGRAM(Cont'd)

B. PROCEDURES (Cont'd)

C. To be initiated -- in the order indicated below -- when system fuel supplies are decreased to 50% of normal target days' operation of coal-fired generation plants and a continued downward trend in coal stocks is anticipated:

1. Discontinue emergency deliveries to neighboring utilities unless the receiving utility agrees to return like quantities of energy within seven days.

2. Request all customers, retail as well as wholesale, to reduce their nonessential use of electric energy by 100%.

3 Request, through mass communication media, curtailment by all other customers a minimum of 15% of their electric use. These uses include lighting, air-conditioning, heating, manufacturing processes, cooking, refrigeration, clothes washing and drying and any other loads that can be curtailed.

4. All customers will be advised of the mandatory program specified below in D.

D. To be initiated when system fuel supplies are decreased to 40% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Implement procedures for curtailment of service to all customers to a minimum service level that is not greater than that required for protection of human life and safety, protection of physical plant facilities and employees' security. This step asks for curtailment of the maximum load possible without endangering life, safety and physical facilities.

2. All customers will be advised of the mandatory program specified below in E.

E. To be initiated when system fuel supplies are decreased to 30% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

Implement procedures for interruption of selected distribution circuits on a rotational basis, while minimizing – to the extent practicable – interruption to facilities that are essential to the public health and safety. (See Section II, Step 14.)

F. The Energy Emergency Control Program will be terminated when:

1. The AEP System's remaining days of operation of coal-fired generation is at least 40% of normal target days' operation, and
2. Coal deliveries have been resumed, and
3. There is reasonable assurance that the AEP System's coal stocks are being restored to adequate levels.

With regard to mandatory curtailments identified in Items C, D, and E above, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

STANDARD NOMINAL VOLTAGES

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

SECONDARY DISTRIBUTION VOLTAGES.

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire.

PRIMARY DISTRIBUTION VOLTAGES.

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y, 19,900 and 34,500Y. (T)

SUBTRANSMISSION LINE VOLTAGES.

The Company's sub transmission voltage levels are 19,900; 34,500; 46,000; and 69,000.

TRANSMISSION LINE VOLTAGES.

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

KENTUCKY POWER COMPANY

Original Sheet No. 5-1
Canceling ______ Sheet No. 5-1

P.S.C. ELECTRIC NO.9

TARIFF F.A.C.
(Fuel Adjustment Clause)

APPLICABLE.

To Tariffs R.S.,Experimental R.S.T.O.D. 2, R.S.-L.M.-T.O.D. R.S.-T.O.D., S.G.S., Experimental S.G.S.T.O.D.,M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S. T.O.D., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L. (T)

RATE.

1. The fuel clause shall provide for periodic adjustment per kwh of sales equal to the difference between the fuel costs per kwh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F\,(m)}{S\,(m)} - \frac{F\,(b)}{S\,(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

    a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

    b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

    c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

    d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

    e. All fuel costs shall be based on weighted average inventory costing.

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacturer, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(Cont'd on Sheet No. 5-2)

DATE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF F.A.C. (Cont'd)
(Fuel Adjustment Clause)

5. Sales (S) shall be all kwh's sold, excluding intersystem sales. Where, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system loss. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts or Public Utilities and Licensees.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by this regulation.

8. Any tariff filing which contains a fuel clause shall conform that clause with this regulation within three (3) months of the effective date of this regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

9 The monthly fuel adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

10. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.

11. At six (6) month intervals, the Commission will conduct public hearings on a utility's past fuel adjustments. The Commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustment it finds unjustified due to improper calculation or application of the charges or improper fuel procurement practice.

12. Every two (2) years following the initial effective date of each utility fuel clause, the Commission in a public hearing will review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Subsection 2.

13. Resulting cost per kilowatt-hour in June 2008 to be used as the base cost in Standard Fuel Adjustment Clause is:

Fuel -	June 2008 =	$16,138,627 = $0.02840/kwh
Sales	June 2008	568,162,000

This, as used in the Fuel Adjustment Clause, is $2.840 cents per kilowatt-hour.

Pursuant to the Public Service Commission Order dated June 11, 2009 in Case No. 2008-00518, the fuel adjustment charge rate for the month of May 2009 and June 2009 usage to be billed in the month of July 2009 and August 2009, respectively shall be calculated using the base fuel cost of 2.124 ¢/kWh. Thereafter the fuel adjustment base cost shall be 2.840 ¢/kWh.

TARIFF R.S.
(Residential Service)

AVAILABILITY OF SERVICE.

Available for full domestic electric service through 1 meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

RATE. (Tariff Codes 015, 017, 022)

Service Charge.. ~~$5.86~~ *$ 8.00* per month (I)
Energy Charge: .... ~~7.191¢~~ *10.044¢* per KWH (I)

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by an Experimental Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 10¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing April 2006 (T) and continue until otherwise directed by the Public Service Commission.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge (T) of 5% of the unpaid balance will be made.

(Cont'd on Sheet No. 6-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Services rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

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KENTUCKY POWER COMPANY

Original Sheet No. 6-2
Canceling Sheet No. 6-2

P.S.C. ELECTRIC NO. 9

TARIFF R.S. (Cont'd)
(Residential Service)

STORAGE WATER HEATING PROVISION.

This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code

012 (a) For Minimum Capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at ~~3.853¢~~ *5.015¢* per KWH. (I)

013 (b) For Minimum Capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at ~~3.853¢~~ *5.015¢* per KWH. (I)

014 (c) For Minimum Capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at ~~3.853¢~~ *5.015¢* per KWH. (I)

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Environmental Surcharge, the Capacity Charge, Transmission Adjustment and the Residential HEAP Charge factors as stated in the above monthly rate. (T)

LOAD MANAGEMENT WATER-HEATING PROVISION. (Tariff Code 011)

For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at ~~3.853¢~~ *5.015¢* per KWH. (I)

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Environmental Surcharge, the Capacity Charge, Transmission Adjustment and the Residential HEAP Charge factors as stated in the above monthly rate. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This service is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes as well as for the usual farm uses outside the home, but it is not extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

(Cont'd on Sheet No. 6-3)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

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TARIFF R.S.(Cont'd)
(Residential Service)

SPECIAL TERMS AND CONDITIONS. (Cont'd)

This tariff is available for single-phase service only. Where 3-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, another applicable tariff will apply to such service.

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S. Tariff. (T)

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement.

TARIFF R.S. - L.M. - T.O.D.
(Residential Service Load Management Time-of-Day)

AVAILABILITY OF SERVICE.

Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

RATE. (Tariff Codes 028, 030, 032, 034)

Service Charge...$ ~~8.36~~ *$10.65* per month (I)
Energy Charge:
All KWH used during on-peak billing period........................... ~~11.366~~ ¢ *16.436¢* per KWH (I)
All KWH used during off-peak billing period............................ ~~3.853~~ ¢ *5.015¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

CONSERVATION AND LOAD MANAGEMENT CREDIT.

For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per KWH for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of this Tariff Schedule.

(Cont'd on Sheet No. 6-5)

TARIFF R.S.-L.M.-T.O.D. (Cont'd)
(Residential Service Load Management Time-of-Day)

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 10¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing April 2006 and continue until otherwise directed by the Public Service Commission. (T)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

SEPARATE METERING PROVISION.

Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $3.00 per month.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment, the availability conditions of this tariff are being violated, it may discontinue billing the Customer under this tariff and commence billing under the appropriate Residential Service Tariff.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

TARIFF R.S. - T.O.D.
(Residential Service Time-of-Day)

AVAILABILITY OF SERVICE.

Available for residential electric service through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff.

RATE. (Tariff Code 036)

Service Charge..$ ~~8.36~~ *$10.65* per month (I)
Energy Charge:
All KWH used during on-peak billing period........................ ~~11.366 ¢~~ *16.436¢* per KWH (I)
All KWH used during off-peak billing period........................ ~~3.853 ¢~~ *5.015¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00P.M. to 7:00A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bill computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 10¢ per meter per month and shall be shown on the residential customers' bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing April 2006 and continue until otherwise directed by the Public Service Commission. (T)

(Cont'd on Sheet No. 6-7)

TARIFF R.S. - T.O.D. (Cont'd)
(Residential Service Time-of-Day)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional Charge of 5% of the unpaid balance will be made. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

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(N)

TARIFF R.S. – T.O.D.2
(Experimental Residential Service Time-of-Day 2)

AVAILABILITY OF SERVICE.

Available on a voluntary, experimental basis to individual residential customers for residential electric service through one single-phase, multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

RATE. (Tariff Code 027)

Service Charge	$ *11.55* per month
Energy Charge:	
All KWH used during Summer on-peak billing period	*13.059¢* per KWH
All KWH used during Winter on-peak billing period	*15.645¢* per KWH
All KWH used during off-peak billing period	*8.770¢* per KWH

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months	On-Peak	Off-Peak
Approximate Percent (%) Of Annual Hours	16%	84%
Winter Period: November 1 to March 31	7:00 A.M. to 11:00 A.M. 6:00 P.M. to 10:00 P.M.	11:00 AM. to 6:00 P.M. 10:00 P.M. to 7:00 A.M.
Summer Period: May 15 to September 15	Noon to 6:00 P.M.	6:00 P.M. to Noon
All Other Calendar Periods	None	Midnight to Midnight

NOTE: All KWH consumed during Saturday and Sunday are billed at the off-peak level.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. (N)

(Cont'd on Sheet No. 6-9)

TARIFF R.S.-T.O.D.2 (Cont'd)
(Experimental Residential Service Time-of-Day 2)

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule. (N)

TRANSMISSION ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 10¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing April 2006 and continue until otherwise directed by the Public Service Commission.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company. (N)

KENTUCKY POWER COMPANY

Original Sheet No. 7-1
Canceling ______ Sheet No. 7-1

P.S.C. ELECTRIC NO. 9

TARIFF S.G.S.
(Small General Service)

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands less than 10 KW and maximum monthly demands of less than 15 KW (excluding the demand served by the Load Management Time-of-Day provisions).

RATE. (Tariff Codes 211, 212)

Service Charge	$ 11.50 per month	
Energy Charge:		
First 500 KWH per month	~~10.013~~ ¢ *13.170¢* per KWH	(I)
All Over 500 KWH per month	~~5.994~~ ¢ *8.174¢* per KWH	(I)

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rate set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional Charge of 5% of the unpaid balance will be made. (T)

(Cont'd on Sheet No. 7-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF S.G.S. (Cont'd.)
(Small General Service)

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 225)

Service Charge	$15.10 per month	
Energy Charge:		
All KWH used during on-peak billing period	~~13.416~~ ¢ *16.473¢* per KWH	(I)
All KWH used during off-peak billing period	~~3.853~~ ¢ *5.015* ¢ per KWH	(I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

The Company shall have the right to require contracts for periods of one year or longer.

OPTIONAL UNMETERED SERVICE PROVISION.

Available to customers who qualify for Tariff SGS and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one Customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The Customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected or the earliest date allowed by Kentucky statute whichever is applicable.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

RATE. (Tariff Codes 204 (Metered), 213 (Unmetered))

Customer Charge	$ 7.50 per month	
Energy Charge:		
First 500 KWH per month	~~10.013~~ ¢ *13.170¢* per KWH	(I)
All Over 500 KWH per month	~~5.994~~ ¢ *8.174¢* per KWH	(I)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet No. 7-3)

TARIFF S.G.S. – T.O.D.
(Experimental Small General Service Time-of-Day Service)

AVAILABILITY OF SERVICE.

Available on a voluntary, experimental basis for general service to customers with 12-month average demands less than 10 kW through one single-phase, multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff. (N)

RATE. (Tariff Code 227)

Service Charge .... $ *15.05* per month
Energy Charge:
All KWH used during Summer on-peak billing period .... *14.202¢* per KWH
All KWH used during Winter on-peak billing period .... *16.259¢* per KWH
All KWH used during off-peak billing period .... *9.258¢* per KWH

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months	On-Peak	Off-Peak
Approximate Percent (%) Of Annual Hours	16%	84%
Winter Period: November 1 to March 31	7:00 A.M. to 11:00 A.M. 6:00 P.M. to 10:00 P.M.	11:00 A.M. to 6:00 P.M. 10:00 P.M. to 7:00 A.M.
Summer Period: May 15 to September 15	Noon to 6:00 P.M.	6:00 P.M. to Noon
All Other Calendar Periods	None	Midnight to Midnight

NOTE: All KWH consumed during weekends are billed at the off-peak level.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. (N)

(Cont'd on Sheet No. 7-4)

KENTUCKY POWER COMPANY

Original Sheet No. 7-4
Canceling ________ Sheet No. 7-4

P.S.C. ELECTRIC NO. 9

TARIFF S.G.S.-T.O.D. (Cont'd)
(Experimental Small General Service Time-of-Day)

ENVIRONMENTAL SURCHARGE. (N)

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

Existing customers may initially choose to take service under this tariff without satisfying any requirement to remain on their current tariff for at least 12 months.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company. (N)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF M.G.S.
(Medium General Service)

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands greater than 10 KW or maximum monthly demands greater than 15 KW, but not more than 100 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	
Tariff Code	215, 216, 218	217, 220	236	
Service Charge per Month	$ 13.50	$ ~~21.00~~ *$28.50*	$ ~~153.00~~ *$209.00*	(I)
Demand Charge per KW	$ ~~1.31~~ *$1.72*	~~$1.28~~ *$1.66*	~~$1.25~~ *$1.63*	(I)
Energy Charge:				
KWH equal to 200 times KW of monthly billing demand	~~8.177~~ ¢ *10.233¢*	~~7.507~~ ¢ *9.394¢*	~~6.933~~ ¢ *8.676¢*	(I)
KWH in excess of 200 times KW of monthly billing demand	~~7.015~~ ¢ *8.778¢*	~~6.715~~ ¢ *8.402¢*	~~6.510~~ ¢*8.147¢*	(I)

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by 6 KW.

The minimum monthly charge for industrial and coal mining customers contracting for 3-phase service after October 1, 1959 shall be $~~5.46~~ *$7.19* per KW of monthly billing demand. (I)

RECREATIONAL LIGHTING SERVICE PROVISION.

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff M.G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

RATE. (Tariff Code 214)

Service Charge ....$13.50 per month
Energy Charge .... ~~7.708¢~~ *9.334¢* per KWH (I)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

(Cont'd on Sheet No. 8-2)

TARIFF M.G.S. (Cont'd.)
(Medium General Service)

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The minimum monthly billing demand shall not be less than (a) the minimum billing demand of 6 KW, or (b) 60% of the greater of (1) the customer's contract capacity in excess of 100 KW or (2) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

LOAD MANAGEMENT TIME-OF-DAY PROVISION. (Tariff Codes 223)

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

(Cont'd on Sheet No. 8-3)

TARIFF M.G.S (Cont'd)
(Medium General Service)

RATE.

Service Charge	$ 3.00 per month	
Energy Charge:		
All KWH used during on-peak billing period	~~12.580~~ ¢ *15.537¢* per KWH	(I)
All KWH used during off-peak billing period	~~3.970~~ ¢ *5.155* ¢ per KWH	(I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

Contracts under this tariff will be required of customers with normal maximum demands of 500 KW or greater. Contracts under this tariff will be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year and to require contracts for Customers with normal maximum demands of less than 500 KW.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other source 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 demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. 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.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

(Cont'd on Sheet No. 8-4)

TARIFF M.G.S.-T.O.D.
(Medium General Service Time-of-Day)

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 10 KW but not more than 100 KW. Availability is limited to the first 500 customers applying for service under this tariff.

RATE. (Tariff Code 229)

Service Charge .... $ 14.30 per month
Energy Charge:
All KWH used during on-peak billing period .... ~~12.580¢~~ *15.537¢* per KWH (I)

All KWH used during off-peak billing period .... ~~3.970¢~~ *5.155¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

(Cont'd on Sheet No. 8-5)

TARIFF M.G.S.-T.O.D. (Cont'd)
(Medium General Service Time-of-Day)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

TARIFF L.G.S.
(Large General Service)

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage				
	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	240, 242	244, 246	248	250	
Service Charge per Month	$ 85.00	$127.50	$535.50	$535.50	
Demand Charge per KW	~~$3.45~~ *$4.29*	~~$3.36~~ *$4.15*	~~$3.30~~ *$4.06*	~~$3.24~~ *$4.02*	(I)
Excess Reactive Charge per KVA	~~$ 2.97~~ *$3.60*	~~$ 2.97~~ *$3.60*	~~$ 2.97~~ *$3.60*	~~$2.97~~ *$3.60*	(I)
Energy Charge per KWH	~~6.309¢~~ *8.109¢*	~~5.604¢~~ *6.750¢*	~~4.539¢~~ *5.046¢*	~~4.154¢~~ *4.678¢*	(I)

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

(Cont'd. On Sheet No. 9-2)

TARIFF L.G.S. (Cont'd.)
(Large General Service)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 251)

Service Charge .... $81.80 per month
Energy Charge:
All KWH used during on-peak billing period .... ~~10.781¢~~ *13.727¢* per KWH (I)
All KWH used during off-peak billing period .... ~~3.942~~ ¢ *5.145¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

(Cont'd on Sheet No. 9-3)

TARIFF L.G.S. (Cont'd)
(Large General Service)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

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 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract 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 billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

TARIFF L.G.S. – T.O.D.
(Large General Service – Time of Day)

AVAILABILITY OF SERVICE.

Available for general service customers with normal maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff. (N)

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	256	257	258	259
Service Charge per Month	*$85.00*	*$ 127.50*	*$535.50*	*$535.50*
Demand Charge per KW	*$8.30*	*$ 5.04*	*$ 0.31*	*$ 0.20*
Excessive Reactive Charge per KVA	*$3.60*	*$ 3.60*	*$ 3.60*	*$ 3.60*
On-Peak Energy Charge per KWH	*10.174¢*	*8.198¢*	*8.010¢*	*7.934¢*
Off-Peak Energy Charge per KWH	*4.145¢*	*3.993¢*	*3.918¢*	*3.881¢*

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule. (N)

(Cont'd on Sheet No. 9-5)

TARIFF L.G.S. – T.O.D. (Cont'd.)
(Large General Service – Time of Day)

DELAYED PAYMENT CHARGE. (N)

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional Charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. (N)

(Cont'd on Sheet No. 9-6)

TARIFF L.G.S. – T.O.D. (Cont'd)
(Large General Service – Time of Day)

CONTRACT CAPACITY. (N)

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

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 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract 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 billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company. (N)

KENTUCKY POWER COMPANY

Original Sheet No. 10-1
Canceling ________ Sheet No. 10-1

P.S.C. ELECTRIC NO. 9

TARIFF Q.P.
(Quantity Power)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with demands less than 7,500 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements, but in no case shall the contract capacity be less than 1,000 KW.

RATE.

	Secondary	Primary	Service Voltage Subtransmission	Transmission	
Tariff Code	356	358	359	360	
Service Charge per month	$ 276.00	$ 276.00	$ 662.00	$ 1,353.00	
Demand Charge per KW					
Of monthly on-peak billing demand	$ ~~13.28~~ *$4.29*	$ ~~11.53~~ *$ 4.15*	$ ~~8.81~~ *$4.06*	$ ~~7.47~~ *$4.02*	(R)
Of monthly off-peak excess billing demand	$ ~~4.79~~ *$9.39*	$ ~~3.31~~ *$6.09*	$ ~~088~~ *$1.34*	$ ~~077~~ *$1.22*	(I)
Energy Charge per KWH	~~3.285¢~~	~~3.233¢~~	~~3.201¢~~	~~3.176¢~~	(D)
First 350 KWH per KW of on-peak billing demand	*8.220¢*	*7.324¢*	*5.700¢*	*5.236¢*	(N)
Over 350 KWH per KW of on-peak billing demand	*3.949¢*	*3.800¢*	*3.729¢*	*3.692¢*	(N)

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand .... ~~$0.67/KVAR~~ *$0.76/* KVAR (I)

MINIMUM DEMAND CHARGE. (N)

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission
$19.24/KW	*$15.52/KW*	*$10.23/KW*	*$8.82/KW*

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months. (N)

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by a Surcharge Adjustment based on a percent of revenue in compliance with the Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

(Cont'd on Sheet No. 10-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF Q.P. (Cont'd.)
(Quantity Power)

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The on-peak billing demand in KW shall be taken each month as the single highest 15-minute integrated peak in KW as registered during the month by a demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator, but the monthly on-peak billing demand so established shall in no event be less than 60% of the greater of (a) the Customer's contract capacity set forth on the contract for electric service or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Off-peak excess billing demand in any month shall be the amount of KW by which the off-peak billing demand exceeds the on-peak billing demand for the month.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a a demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

(Cont'd on Sheet No. 10-3)

TARIFF Q.P. (Cont'd)
(Quantity Power)

CONTRACT CAPACITY

The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW but less than 7,500 KW; in multiplies of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customer who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customer having other sources of energy supply, but who desire to purchase standby or back-up electric s 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 nor more than 7,500 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.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 11-1
Canceling ________ Sheet No. 11-1

P.S.C. ELECTRIC NO. 9

TARIFF C.I.P. - T.O.D.
(Commercial and Industrial Power - Time-of-Day)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with normal maximum demands of 7,500 KW and above. Customers shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 7,500 KW.

RATE.

	Primary	Subtransmission	Transmission	
Tariff Code	370	371	372	
Service Charge per Month	$ 276.00	$ ~~662.00~~ *$794.00*	$ 1,353.00	(I)
Demand Charge per KW				
On-peak	~~$13.79~~ *$19.41*	~~$10.83~~ *$14.26*	~~$9.35~~ *$12.88*	(I)
Off-peak	~~$3.68~~ *$ 6.09*	$ ~~0.98~~ *$ 1.34*	~~$0.84~~ *$1.21*	(I)
Energy Charge per KWH	~~2.874¢~~ *3.052¢*	~~2.849¢~~ *2.994¢*	~~2.829¢~~ *2.96 7¢*	(I)

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand .... ~~$ 0.67/~~ KVAR *$0.76/KVAR* (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Primary	Subtransmission	Transmission	
~~$14.79/KW~~ *$19.50 /KW*	~~$11.80/KW~~ *$14.35/KW*	~~$10.32/KW~~ *$12.99/KW*	(I)

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months. (T)

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the KWH is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

(Cont'd on Sheet No. 11-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF C.I.P. - T.O.D. (Cont'd.)
(Commercial and Industrial Power - Time-of-Day)

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity ChargeTariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVAR's as registered during the month by the demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator.

(Cont'd on Sheet No. 11-3)

TARIFF C.I.P. – T.O.D. (Cont'd)
(Commercial and Industrial Power – Time-of-Day)

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount equal to or greater than 7,500 KW, in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

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 7,500 KW. The Company shall not be obligated to supply demands in excess of the contract for 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.

A customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by customer. When the size of the customer's load necessitates the delivery of energy to the customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the customer's system irrespective of contrary provisions in Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power)

AVAILABILITY OF SERVICE.

Available for service to customers who contract for service under one of the Company's interruptible service options. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 60,000 kW. (T)

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

CONDITIONS OF SERVICE.

The Company will offer eligible customers the option to receive service from a menu of interruptible power options pursuant to a contract agreed to by the Company and the Customer.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written offer containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet normal maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than ~~5,000~~ *1,000* KW at any delivery point. (T)

RATE. (Tariff Code 321)

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a difference from the firm service rates otherwise available to the Customer.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd on Sheet No. 12-2)

KENTUCKY POWER COMPANY

Original Sheet No 12-2
Canceling ________ Sheet No. 12-2

P.S.C. ELECTRIC NO. 9

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the Customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

TERM OF CONTRACT

The length of the agreement and the terms and conditions of service will be stated in the agreement between the Company and the Customer.

CONFIDENTIALITY

All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR5:001, Section 7 and the request is granted.

(Cont'd on Sheet No. 12-3)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2009-00459 dated

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

SPECIAL TERMS AND CONDITIONS

Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

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 ~~5,000~~ *1,000* KW. (T)

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 13-1
Canceling ______ Sheet No. 13-1

P.S.C. ELECTRIC NO. 9

TARIFF M.W.
(Municipal Waterworks)

AVAILABILITY OF SERVICE.

Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

RATE. (Tariff Code 540)

Service Charge .... $22.90 per month
Energy Charge:
All KWH Used Per Month .... ~~6.866¢~~ per KWH *8.380¢* per KWH (I)

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus ~~$3.65~~ *$4.57* per KVA as determined from customer's total connected load. (I)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

TRANSMISSION ADJUSTMENT. (N)

Bills computed according to the rates set forth herein will be increased or decreased by a Transmission Adjustment based on a percent of revenue in compliance with the Transmission Adjustment contained in Sheet Nos. 35-1 and 35-2 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

(Cont'd on Sheet No. 13-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF M.W. (Cont'd)
(Municipal Waterworks)

PAYMENT.

Bills will be rendered monthly and will be due and payable on or before the due date stated on the bill.

TERM OF CONTRACT.

Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

TARIFF O.L.
(Outdoor Lighting)

AVAILABILITY OF SERVICE.

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable.

RATE.

A. OVERHEAD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
094		100 watts (9,500 Lumens)	$ ~~7.18~~ *$10.00* per lamp	(I)
113		150 watts (16,000 Lumens)	$ ~~8.20~~ *$11.30* per lamp	(I)
097		200 watts (22,000 Lumens)	$ ~~10.05~~ *$14.00* per lamp	(I)
103		250 watts (28,000 Lumens)	*$14.00 per lamp*	(N)
098		400 watts (50,000 Lumens)	$ ~~16.33~~ *$22.15* per lamp	(I)
	2.	Mercury Vapor		
093*		175 watts (7,000 Lumens)	$ ~~7.81~~ *$11.60* per lamp	(I)
095*		400 watts (20,000 Lumens)	$~~13.48~~ *$20.00* per lamp	(I)

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. POST-TOP LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
111		100 watts (9,500 Lumens)	$ ~~10.53~~ *$15.65* per lamp	(I)
122		150 Watts (16,000 Lumens)	$ ~~17.15~~ *$25.45* per lamp	(I)
121		100 Watts Shoe Box (9,500 Lumens)	*$20.50 per lamp*	(N)
120		250 Watts Shoe Box (28,000 Lumens))	*$24.60 per lamp*	(N)
126		400 Watts Shoe Box (50,000 Lumens))	*$28.70 per lamp*	(N)
	2.	Mercury Vapor		
099*		175 watts (7,000 Lumens)	$ ~~8.96~~ *$13.25* per lamp	(I)

Company will provide lamp, photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits.

C. FLOOD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
107		200 watts (22,000 Lumens)	$ ~~11.30~~ *$15.65* per lamp	(I)
109		400 watts (50,000 Lumens)	$ ~~16.08~~ *$21.75* per lamp	(I)
	2.	Metal Halide		
110		250 watts (20,500 Lumens)	$ ~~17.34~~ *$20.35* per lamp	(I)
116		400 watts (36,000 Lumens)	$ ~~22.93~~ *$26.90* per lamp	(I)
131		*1000 watts (110,000 Lumens)*	$ ~~49.70~~ *$58.35* per lamp	(I)
130		250 watts Mongoose (19,000 Lumens)	*$22.35 per lamp*	(N)
136		400 watts Mongoose (40,000 Lumens)	*$26.20 per lamp*	(N)

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

*These lamps are not available for new installations.

(Cont'd on Sheet No. 14-2)

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

RATE. (Cont'd.)

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Wood pole .... $ ~~2.30~~ *$3.40* per month (I)
Overhead wire span not over 150 feet .... $ ~~1.30~~ *$1.95* per month (I)
Underground wire lateral not over 50 feet .... $~~5.35~~ *$7.15* per month (I)
(Price includes pole riser and connections)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause, System Sales Clause and the Capacity Charge computations are as follows:

(T)

	METAL HALIDE			MERCURY VAPOR		HIGH PRESSURE SODIUM				
	250 WATTS	400 WATTS	1000 WATTS	175 WATTS	400 WATTS	100 WATTS	150 WATTS	200 WATTS	250 WATTS	400 WATTS
JAN	127	199	477	91	199	51	74	106	130	210
FEB	106	167	400	76	167	43	62	89	109	176
MAR	106	167	400	76	167	43	62	89	109	176
APR	90	142	340	65	142	36	53	76	93	150
MAY	81	127	304	58	127	32	47	68	83	134
JUNE	72	114	272	52	114	29	42	61	74	120
JULY	77	121	291	55	121	31	45	65	79	128
AUG	88	138	331	63	138	35	51	74	90	146
SEPT	96	152	363	69	152	39	57	81	99	160
OCT	113	178	427	81	178	45	66	95	116	188
NOV	119	188	449	86	188	48	70	100	122	198
DEC	129	203	486	92	203	52	75	108	132	214
TOTAL	1204	1896	4540	864	1896	484	704	1012	1236	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

(Cont'd on Sheet No. 14-3)

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

A delayed payment charge on residential customer accounts will be applied pursuant to the delayed payment charge on Tariff R.S. On all accounts other than residential not paid in full on or before the due date stated on the bill, an additional charge of 5% of the unpaid portion will be made. (T)

HOURS OF LIGHTING.

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

OWNERSHIP OF FACILITIES.

All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

TERM OF INITIAL SERVICE.

Term of initial service shall be required for an initial period of one year.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

TARIFF S.L.
(Street Lighting)

AVAILABILITY OF SERVICE.

Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems.

RATE. (Tariff Code 528)

A. Overhead Service on Existing Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)	$	~~5.93~~ *$7.40* per lamp	(I)
150 watts (16,000 lumens)	$	~~6.85~~ *$8.55* per lamp	(I)
200 watts (22,000 lumens)	$	~~8.65~~ *$10.60* per lamp	(I)
400 watts (50,000 lumens)	$	~~12.88~~ *$16.95* per lamp	(I)

B. Service on New Wood Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)	$	~~9.23~~ *$10.60* per lamp	(I)
150 watts (16,000 lumens)	$	~~10.20~~ *$11.75* per lamp	(I)
200 watts (22,000 lumens)	$	~~11.90~~ *$13.60* per lamp	(I)
400 watts (50,000 lumens)	$	~~16.13~~ *$19.00* per lamp	(I)

C. Service on New Metal or Concrete Poles*

1. High Pressure Sodium

100 watts (9,500 lumens)	$	~~15.13~~ *$22.45* per lamp	(I)
150 watts (16,000 lumens)	$	~~15.90~~ *$23.60* per lamp	(I)
200 watts (22,000 lumens)	$	~~20.20~~ *$30.00* per lamp	(I)
400 watts (50,000 lumens)	$	~~21.98~~ *$32.65* per lamp	(I)

*These lamps are not available for new installations

Lumen rating is based on manufacturer's rated lumen output for new lamps.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. *The monthly kilowatt-hours for Fuel Adjustment Clause, System Sales Clause and the Capacity Charge computations are as follows:* (T)

(Cont'd on Sheet No. 15-2)

TARIFF S.L. (Cont'd.)
(Street Lighting)

FUEL ADJUSTMENT CLAUSE. (Cont'd.)

	HIGH PRESSURE SODIUM			
MONTH	100 WATTS	150 WATTS	200 WATTS	400 WATTS
JAN	51	74	106	210
FEB	43	62	89	176
MAR	43	62	89	176
APR	36	53	76	150
MAY	32	47	68	134
JUNE	29	42	61	120
JULY	31	45	65	128
AUG	35	51	74	146
SEPT	39	57	81	160
OCT	45	66	95	188
NOV	48	70	100	198
DEC	52	75	108	214
TOTAL	484	704	1012	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

SPECIAL FACILITIES.

When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities.

(Cont'd On Sheet No. 15-3)

TARIFF S.L. (Cont'd.)
(Street Lighting)

PAYMENT.

Bills are due and payable within ten (10) days of the mailing date.

HOURS OF LIGHTING.

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

TERM OF CONTRACT.

Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

TARIFF C. A. T. V.
(Cable Television Pole Attachment)

AVAILABILITY OF SERVICE.

Available to operators of cable television systems (Operators) furnishing cable television service in the operating area of Kentucky Power Company (Company) for attachments of aerial cables, wires and associated appliances (attachments) to certain distribution poles of Kentucky Power Company.

RATE.

Charge for attachments on a two-user pole .... $ 7.21 per pole/year
Charge for attachments on a three-user pole .... $ 4.47 per pole/year

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost	x	Usage Factor	x	Carrying Charge	= Rate Per Pole

DELAYED PAYMENT CHARGE.

This Tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid an additional charge of 5% of the unpaid balance will be made.

POLE SUBJECT TO ATTACHMENT.

When an Operator proposes to furnish cable television service within the Company's operating area and desires to make attachments on certain distribution poles of Company, Operator shall make written application, on a form furnished by Company, to install attachments specifying the location of each pole in question, the character of its proposed attachments and the amount and location of space desired, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed attachment and any other facilities attached to the pole. Within twenty-one (21) days after receipt of the application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Operator shall reimburse Company for any expenses incurred in reviewing such written applications for attachment. Operator shall have a non-exclusive right to use such poles of Company as may be used or reserved for use by Operator and any other poles of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant, by contract or otherwise to others rights or privileges to use any poles of the Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted. All poles shall be and remain the property of Company regardless of any payment by Operator toward their cost and Operator shall, except for the rights provided hereunder, acquire no right, title or interest in or to any such pole.

STANDARDS FOR INSTALLATION.

All attachments and associated equipment of Operator (including without limitation, power supplies) shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the poles covered by this Tariff. All such attachments and equipment shall be installed and at all times maintained by Operator so as to comply at least with the minimum requirements of the National Electrical Safety Code and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction there over. Power supply apparatus having as its largest dimension more than sixteen inches must be placed on a separate pole to be installed by Operator. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

(Cont'd on Sheet No. 16-2)

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING.

In any case Operator proposes to install attachments on a pole to be erected by Company in a new location, and to provide adequate space or strength to accommodate such attachments (either at the request of Operator to comply with the aforesaid codes and regulations) such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or share ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Title to the new pole shall remain with the Company. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of removing each of their respective facilities or attachments from the existing pole and reestablishing the same or like facilities or attachments on the newly-installed pole.

If Operator's desired attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon of any other person, or if because of Operator's proposed attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company proposed to replace an existing pole on which Operator has any attachment, or Company proposed to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's attachment, or if as a result of any inspection of Operator's attachments Company determines that any such attachments are not in accordance with applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than 48 hours notice of such proposed replacement or change, or any such violation or hazard, unless an emergency requires a shorter period. In such event, Operator shall at its expense relocate, rearrange or modify its attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

POLE INSPECTION.

Company reserves the right to inspect each new or proposed installation of Operator on Company's poles. In addition, Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

(Cont'd. On Sheet No. 16-3)

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

UNAUTHORIZED ATTACHMENTS.

Operator shall make no attachment to or other use of any pole of Company or any facilities of Company thereon, except as authorized. Should such unauthorized attachment or use be made, Operator shall pay to the Company on demand two times the charges and fees, including but not limited to, any payable under the headings "RATES" and "POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING" that would have been payable had such attachment been made on the date following the date of the last previous inspection required to be made by Company under applicable regulations of the Kentucky Public Service Commission.

ABANDONMENT BY OPERATOR.

Operator may at any time abandon the use of a pole hereunder by removing therefrom all of its attachments and by giving written notice thereof, on a form provided by the Company, and no pole shall be considered abandoned until such notice is received.

INDEMNITY.

Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers or because of interference with television reception of said subscribers or others, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the facilities of Operator on the poles of Company under this Tariff, when due to any act, omission or negligence of Operator, or to any such act, omission or negligence of Operator's respective representatives, employees, agents or contractors.

INSURANCE.

Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $1,000,000 for any one occurrence
(b) Comprehensive property damage liability insurance in an amount not less than $500,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making attachments at Company's poles, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company fifteen (15) days' prior written notice of any cancellation of or material change in such policies.

EASEMENTS.

Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said attachments on Company's poles.

(Cont'd on Sheet 16-4)

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

CHARGES AND FEES.

Operator agrees to pay Company in advance, semi-annually, charges to be computed as set forth in Tariff, and such other charges as may be provided for herein, for the use of each of Company's poles, any portion of which is occupied by, or reserved at Operator's request for the attachments of Operator.

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial attachments including without limitation the amounts set forth herein before and the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make attachments.

FEES FOR ADDITIONAL ATTACHMENTS OR REMOVALS.

For attachments made or removed which are reported to the Company between billing dates, Operator shall be billed or credited a prorated amount of the annual charge effective with the date of attachment or removal on the Operator's next bill.

ADVANCE BILLING

Payment of amounts due hereunder are due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due fifteen (15) days from the date of the invoice therefore. In all amounts not so paid an addition charge of five percent (5%) will be assessed. Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by company of any work. In such a case, Company shall invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined.

DEFAULT OR NON-COMPLIANCE.

If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within thirty (30) days, after written notice from Company to correct such default or non-compliance, Company may, as its option forthwith take any one or more of the following actions: terminate the specific permit or permits covering the poles to which such default or non-compliance is applicable; remove, relocate or rearrange attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults terminate Operator's right of attachment. No liability shall be incurred by Company because of any or all such actions except for negligent destruction by the Company of CATV equipment in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company.

PRIOR AGREEMENTS.

This Tariff terminates and supersedes any previous agreement, license or joint use affecting Company's poles and Operator's attachments covered herein.

(Cont'd on Sheet No. 16-5)

TARIFF C. A. T. V. (Cont'd)
(Cable Television Pole Attachment)

ASSIGNMENT.

This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of the Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

PERFORMANCE WAIVER.

Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

PRESERVATION OF REMEDIES.

No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

HEADINGS.

Headings used in this Tariff are inserted only for the convenience of the parties and shall not affect the interpretation or construction of this Tariff.

KENTUCKY POWER COMPANY

Original Sheet No. 17-1
Canceling ______ Sheet No. 17-1

P.S.C. ELECTRIC NO. 9

TARIFF COGEN/SPP I
(Cogeneration and/or Small Power Production--100 KW or Less)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 -The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.

Options 2 & 3 - Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	~~$ 6.75~~ $7.10	~~$ 8.45~~ $8.15	(I) (R
T.O.D. Measurement	~~$ 7.55~~ $7.50	~~$ 8.85~~ $8.50	(R) (R

(Cont'd on Sheet No. 17-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd.)

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 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.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH	~~2.81~~ ¢/KWH *2.90¢KWH*	(I)
T.O.D. Meter		
On-Peak KWH	~~3.54~~ ¢/ KWH *3.06¢/KWH*	(R)
Off-Peak KWH	~~2.29~~ ¢/KWH *2.78¢/KWH*	(I)

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. ~~$0.72~~/ *$2.75*/KW/month, times the lowest of: (I)

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

(Cont'd on Sheet No. 17-3)

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit (Cont'd.)

If T.O.D. energy meters are used,

B. $ ~~1.73~~/ *$6.59*/KW/month, times the lowest of: (I)

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 327, or

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M. local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

KENTUCKY POWER COMPANY

Original Sheet No. 18-1
Canceling ______ Sheet No. 18-1

P.S.C. ELECTRIC NO.9

TARIFF COGEN/SPP II
(Cogeneration and/or Small Power Production--Over 100 KW)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of over 100 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.

Options 2 & 3- Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	$ ~~6.75~~ *$7.10*	$ ~~8.45~~ *$8.15*	(I) (R)
T.O.D. Measurement	$ ~~7.55~~ *$7.50*	$ ~~8.85~~ *$8.50*	(R) (R)

(Cont'd on Sheet No. 18-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF COGEN/SPP II (Cont'd.)

(Cogeneration and/or Small Power Production--Over 100 KW)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd)

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 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.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH	~~2.81~~ ¢KWH *2.90¢KWH*	(I)
T.O.D. Meter		
On-Peak KWH	~~3.54~~ ¢/KWH *3.06¢/KWH*	(R)
Off-Peak KWH	~~2.29~~ ¢/KWH *2.78¢/KWH*	(I)

(Cont'd on Sheet No. 18-3)

TARIFF COGEN/SPP II (Cont'd.)
(Cogeneration and/or Small Power Production--Over 100 KW)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. $~~0.72/KW~~/ *$2.75/KW/* month, times the lowest of: (I)

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. $~~1.73~~/KW/ *$6.59/KW/*month, times the lowest of: (I)

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 327, or

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

KENTUCKY POWER COMPANY

Original Sheet No. 19-1
Canceling ______ Sheet No. 19-1

P.S.C. ELECTRIC NO. 9

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.- I.R.P., M.W., O.L. and S.L. (T)

RATE.

1. When the monthly net revenues from system sales are above the monthly base net revenues from system sales, as provided in paragraph 4 below, an additional credit equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below. (T)

   System Sales Adjustment Factor (A) = Lesser of (.5 [Tm - Tb])/Sm and (.5 [Cm – Cb])/Sm

   In the above formulas "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, "C" is Kentucky Power Company's (KPCo) cumulative net revenues from system sales in the current (m) and base (b) periods, and "S" is the KWH sales in the current (m) period, all defined below. (T)

2. When the monthly net revenues from system sales are below the monthly base net revenues from system sales, as provided in paragraph 4 below, an additional charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below. (T)

   System Sales Adjustment Factor (A) = Lesser of (.5 [Tb - Tm])/Sm and (Rmp)/Sm

   In the above formulas "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, "R" is the cumulative net credits and charges for months (mp) of the current annual period prior to the current (m) period, and "S" is the KWH sales in the current (m) period, all defined below. (T)

   Charges under paragraph 2 may only offset credits provided under paragraph 1 in previous months during the annual period which includes the expense months of May 1 to April 30. In no event shall the charges assessed under this paragraph 2 be greater than the credits provided under paragraph 1 for any annual period which includes the expense months of May 1 to April 30. (T)

3. The net revenue from American Electric Power (AEP) System sales to non-associated companies that are shared by AEP Member Companies, including KPCo, in proportion to their Member Load Ratio and as reported in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

   a. KPCo's Member Load Ratio share of total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's Member Load Ratio share of total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties. (T)

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

(Cont'd on Sheet No. 19-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2009-00459 dated

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

4. The base monthly net revenues from system sales are as follows:

Expense Month	Monthly Base Net Revenues from System Sales (Total Company Basis)	Cumulative Annual Base Net Revenues from System Sales (Total Company Basis)
May	$ 616,234	$ 616,234
June	2,136,652	2,752,886
July	1,850,577	4,603,463
August	1,739,665	6,343,128
September	1,538,455	7,881,583
October	1,568,121	9,449,704
November	528,886	9,978,590
December	335,167	10,313,757
January	1,530,489	11,844,246
February	1,371,521	13,215,767
March	1,307,472	14,523,239
April	767,124	15,290,363
	$ 15,290,363	

(T)

(T)

5. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

6. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

7. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

8. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Tariff F.T.
(Franchise Tariff)

AVAILABILITY OF SERVICE.

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town of the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

TARIFF T. S.
(Temporary Service)

AVAILABILITY OF SERVICE.

Available for temporary lighting and power service where capacity is available.

RATE.

Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of connection and disconnection.

MINIMUM CHARGE.

The same minimum charge as provided for in any applicable tariff, shall be applicable to such temporary service and for not less than one full monthly minimum.

TERM.

Variable.

SPECIAL TERMS AND CONDITIONS.

A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required.

This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature.

See Terms and Conditions of Service.

KENTUCKY POWER COMPANY

Original Sheet No 22-1
Canceling ________ Sheet No. 22-1

P.S.C. ELECTRIC NO. 9

TARIFF D.S.M.C.
(Demand-Side Management Adjustment Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., and M.W. (T)

RATE.

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{Adjustment Factor} = \frac{DSM(c)}{S(c)}$$

   Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      (i) the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      (ii) the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      (iii) the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2011. (T)

(Cont'd on Sheet No. 22-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

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KENTUCKY POWER COMPANY

Original Sheet No. 22-2
Canceling ________ Sheet No. 22-2

P.S.C. ELECTRIC NO. 9

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

RATE. (Cont'd.)

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

		CUSTOMER SECTOR	
	RESIDENTIAL ($ Per KWH)	COMMERCIAL**	INDUSTRIAL*
Floor Factor =	0.000396	-0-	- 0 -
Ceiling Factor =	0.000885	-0-	- 0 -

8. The DSM Adjustment Clause factor ($ Per KWH) for each customer sector which fall within the range defined in Item 7 above is as follows:

		CUSTOMER SECTOR	
	RESIDENTIAL	COMMERCIAL **	INDUSTRIAL*
DSM (c)	401,129	-0-	- 0 -
S (c)	626,249,600	-0-	- 0 -
Adjustment Factor	$ 0.000641	-0-	- 0 -

*The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

** The Commercial Sector has been discontinued pursuant to the Commission's Order dated November 21, 2005

DATE OF ISSUE December 29, 2009 EFFECTIVE DATE Service rendered on or after January 29, 2010

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
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KENTUCKY POWER COMPANY

Original Sheet No. 23-1
Canceling Sheet No. 23-1

P.S.C. ELECTRIC NO. 9

TARIFF N.M.S.C.
(Net Merger Savings Credit) (D)

THE NET MERGER SAVINGS CREDIT TARIFF IS DISCONTINUED EFFECTIVE WITH THE DATE OF THE COMMISSION'S ORDER IN CASE NO. 2009-00459.

SHEET NO. 23-1 IS RESERVED FOR FUTURE USE

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

KENTUCKY POWER COMPANY

Original Sheet No. 24-1
Canceling ________ Sheet No. 24-1

P.S.C. ELECTRIC NO. 9

RIDER E.C.S. - C. & E.
(Emergency Curtailable Service – Capacity & Energy Rider) (N)

AVAILABILITY OF SERVICE.

This rider shall be available through May 31, 2012 for Emergency Curtailable Service (ECS) to Kentucky Power Company (KPCo or the Company) retail customers taking firm service from the Company under Tariffs MGS, MGS-TOD, LGS, LGS-TOD, QP,CIP-TOD or MW. The Company reserves the right to limit the amount of ECS capacity contracted under this Rider. The Company will take ECS requests in the order received. If ECS requests exceed the Company's needs to meet its FRR requirements, the Company will bid the remaining capacity into the PJM RPM auction if the PJM rules permit it, providing those customers the compensation available under this rider. The PJM Demand Response Program shall not be available to customers eligible for this service.

CONDITIONS OF SERVICE.

1. The provisions of this Rider qualify under the PJM Emergency Demand Response Program as of the effective date. If the PJM Tariff is subsequently revised, the Company reserves the right to make comparable changes to this Rider in order to continue to qualify under the PJM Emergency Demand Response Program.

2. The Company reserves the right to call for (request) customers to curtail use of the customer's ECS load when, in the sole judgment of the Company, an emergency condition exists on the American Electric Power (AEP) System or the PJM Interconnection, L.L.C. (PJM) RTO. The Company shall determine that an emergency condition exists if curtailment of load served under this Rider is necessary in order to maintain service to the Company's other firm service customers according to the AEP System Emergency Operating Plan or if PJM issues an Emergency Curtailable Service Notice.

3. The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the customer's ECS load shall be curtailed within 2 hours if so requested.

4. In no event shall the customer be subject to ECS load curtailment under the provisions of this Rider for more than 60 hours during any year or for more than 10 interruptions per year. However, a customer must agree to be subject to ECS Curtailments of up to 6-hour duration for each curtailment event, on weekdays between 12 noon to 8 pm for the months May through September and between 6 am to 10 pm for the months October through April.

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

6. No responsibility or liability of any kind shall attach to or be incurred by the company or the AEP system 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.

7. If no Emergency events are called during the summer of the delivery year, the Company will conduct a test and verify the customer's ability to curtail as required by the PJM RTO. The Company reserves the right to re-test the customer if the Company does not achieve the minimum 80% compliance testing standards for all of the Company's ECS customers as required by PJM. These tests must be conducted for one hour during the on-peak hours from June 1 through September 30 during the delivery year. (N)

(Cont'd on Sheet No. 24-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
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RIDER E.C.S. - C. & E. (Cont'd)
(Emergency Curtailable Service – Capacity & Energy Rider)

CONDITIONS OF SERVICE (Cont.) (N)

8. The Company reserves the right to discontinue service to the customer under this Rider if the customer fails to curtail under any circumstances as requested by the Company.

CURTAILED DEMAND.

The customer's Curtailed Demand is determined based upon which method of measurement the customer chooses. The customer may choose one of two methods to measure the curtailed demand: 1) Guaranteed Load Drop (GLD) or 2) Firm Service Level (FSL). The method chosen shall remain in effect for an entire delivery year, June 1 through May 31 of the following year as defined by PJM.

Guaranteed Load Drop (GLD) Method

GUARANTEED LOAD DROP (GLD).

Each customer must designate a Guaranteed Load Drop, which amount shall be the minimum demand reduction that the customer will provide for each hour during a curtailment event or during a curtailment test.

CUSTOMER BASELINE LOAD CALCULATION.

A Customer Baseline Load (CBL) will be calculated for each hour corresponding to each event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the highest 4 out of the 5 most recent similar non-event days in the period preceding the relevant load reduction event. The highest load days are defined as the similar days (Weekday, Saturday, Sunday/Holiday) with the highest energy consumption spanning the event period hours. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the company and customer may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern.

CURTAILED ENERGY.

The Curtailed Energy shall be determined for each event hour, defined as the difference between the customer's CBL for that hour and the customer's metered load for that hour.

CURTAILMENT CREDITS.

The **Curtailment Energy Credit** shall be 80 percent of the AEP East Load Zone hourly Real-Time Locational Marginal Price (LMP) established by PJM (including congestion and marginal losses) for each event hour.

The **Curtailment Demand Credit** shall be 80 percent of the Reliability Pricing Model (RPM) auction price established by PJM in its Base Residual capacity auction for the current delivery year, expressed in \$/MW-day multiplied by the GLD MWs. (N)

(Cont'd on Sheet No. 24-3)

KENTUCKY POWER COMPANY

Original Sheet No. 24-3
Canceling ________ Sheet No. 24-3

P.S.C. ELECTRIC NO. 9

RIDER E.C.S. - C. & E. (Cont'd)
(Emergency Curtailable Service – Capacity & Energy Rider)

MONTHLY DEMAND CREDIT. (N)

The Monthly Demand Credit shall be equal to one-twelfth of the product of the Guaranteed Load Drop and the Curtailment Demand Credit times 365. 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.

MONTHLY EVENT CREDIT.

An Event Credit shall be calculated for each event hour equal to the product of the Curtailed Energy for that hour and the Curtailment Energy Credit for that hour. The Monthly Event Credit shall be the sum of the hourly event credits for all events occurring in the calendar month, but shall not exceed the customer's monthly energy charge under the applicable tariff. The customer shall not receive event credit for any curtailment periods to the extent that the customer's curtailable load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any event other than the customer's normal operating conditions.

NONCOMPLIANCE CHARGE.

If the customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Charge shall apply. If a customer does not reduce load by the full GLD, a noncompliance charge shall apply. For this purpose, Actual Load Drop (ALD) is defined as the difference between the customer's CBL (Customer Baseline Load) and their actual hourly load. If the ALD is less than the GLD, the customer will be in non-compliance.

The Noncompliance Demand Charge will be calculated based on the number of events missed because the customer did not curtail and the total number of events called by AEP to date. A penalty will be determined as the non-compliance load times the RPM auction price ($/MW-day) times 365, (e.g. curtailment of only 80 MW of a 100 MW ECS load is non-compliance and counts as a missed event, but the customer's annual payment will be reduced only for the 20 MW non-compliance load times the appropriate percentage from the table below). The penalty will then be multiplied by the percentage of reduction based upon the number of non-compliance events for the customer compared to the number of events called. Below is a table of annual payment reduction percentages.

Annual Payment Reduction Percentages for Non-compliance					
	Number of Events Called Annually				
Missed Events	1	2	3	4	5 or more
1	100%	50%	33%	25%	20%
2		100%	67%	50%	40%
3			100%	75%	60%
4				100%	100%

If the customer misses four events, the customer will be charged 100% of the total annual payment amount. The Company and the customer will discuss methods to comply during future events, but ultimately the customer can be dismissed from the program if either party is not satisfied that the problem has been resolved. Further, the customer's service under this Rider may be discontinued pursuant to the Conditions of Service. (N)

(Cont'd on Sheet No. 24-4)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
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Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

RIDER E.C.S. - C. & E. (Cont'd)
(Emergency Curtailable Service – Capacity & Energy Rider)

Firm Service Level (FSL) Method

PEAK LOAD CONTRIBUTION. (N)

A Customer's Peak Load Contribution (PLC) will be calculated each year as the average of its load during PJM's five highest peak loads during the twelve month period ended October 31 of the previous year.

AVAILABLE CURTAILBLE DEMAND (ACD).

Each customer must designate an Available Curtailable Demand, defined as the difference between the PLC and the Firm Service Level (FSL). The FSL demand is the level to which the customer agrees to reduce load to or below for each hour during a curtailment event.

CUSTOMER BASELINE LOAD CALCULATION.

A Customer Baseline Load (CBL) will be calculated for each hour corresponding to each event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the highest 4 out of the 5 most recent similar non-event days in the period preceding the relevant load reduction event. The highest load days are defined as the similar days (Weekday, Saturday, Sunday/Holiday) with the highest energy consumption spanning the event period hours. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the company and customer may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern.

CURTAILED ENERGY.

The Curtailed Energy shall be determined for each event hour, defined as the difference between the customer's CBL for that hour and the customer's metered load for that hour.

CURTAILMENT CREDITS.

The Curtailment Demand Credit shall be 80 percent of the Reliability Pricing Model (RPM) auction price established by PJM in its Base Residual capacity auction for the current delivery year, expressed in $/MW-day multiplied by the Available Curtailable Demand.

MONTHLY DEMAND CREDIT.

The Monthly Demand Credit shall be equal to one-twelfth of the product of the Available Curtailable Demand and the Curtailment Demand Credit ($/MW-day) times 365. 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.

MONTHLY EVENT CREDIT.

An Event Credit shall be calculated for each event hour equal to the product of the Curtailed Energy for that hour and the Curtailment Energy Credit for that hour. The Monthly Event Credit shall be the sum of the hourly event credits for all events occurring in the calendar month, but shall not exceed the customer's monthly energy charge under the applicable tariff. The customer shall not receive event credit for any curtailment periods to the extent that the customer's curtailable load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any event other than the customer's normal operating conditions. (N)

(Cont'd on Sheet No. 24-5)

RIDER E.C.S. - C. & E. (Cont'd)
(Emergency Curtailable Service – Capacity & Energy Rider)

NONCOMPLIANCE CHARGE. (N)

If the customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Charge shall apply. If a customer is operating at or below their designated Firm Service Level during an event, it will be understood that they have no capacity available with which to comply and will not be charged a noncompliance penalty. If the metered demand during the curtailment event is above the designated FSL, the customer will be considered non-compliant. The amount of non-compliance demand is equal to the difference between the customer's metered demand and the designated FSL.

The Noncompliance Demand Charge will be calculated based on the number of events during which the customer was noncompliant and the total number of events called by AEP to date. A penalty will be determined as the amount of non-compliance load times the RPM auction price ($/MW-day) times 365, (e.g. curtailment of only 80 MW of a 100 MW ECS load is non-compliance and counts as a missed event, but the customer's annual payment will be reduced only for the 20 MW non-compliance load times the appropriate percentage from the table below). The penalty will then be multiplied by the percentage of reduction based upon the number of non-compliance events for the customer compared to the number of events called. Below is a table of annual payment reduction percentages.

Annual Payment Reduction Percentages for Non-compliance					
	Number of Events Called Annually				
Missed Events	1	2	3	4	5 or more
1	100%	50%	33%	25%	20%
2		100%	67%	50%	40%
3			100%	75%	60%
4				100%	100%

If the customer misses four events, the customer will be charged 100% of their total annual payment amount, will be dismissed from the program, and may not be eligible to participate in the program until both parties are satisfied that the problem has been resolved. Further, the customer's service under this Rider may be discontinued pursuant to the Conditions of Service.

Additional Provisions

CUSTOMER CREDIT.

The monthly credit(s) will be provided to the customer by check within 60 days after the end of the month. A customer may request aggregation of individual customer accounts into a single credit.

CUSTOMER CHARGE.

Customers taking service under this Rider shall pay a monthly customer charge of $10.00 per account to offset the cost of the customer-related expenses for additional load determination and billing expenses. If a change in metering equipment or functionality is required, customers taking service under this Rider shall pay the additional cost of installation. The Company will make available to the customer the real time pulse metering data, if requested by the customer, for an additional fee. (N)

(Cont'd on Sheet No. 24-6)

RIDER E.C.S. - C. & E. (Cont'd)
(Emergency Curtailable Service – Capacity & Energy Rider)

TERM. (N)

Contracts under this Rider shall be made for an initial period of one year, corresponding with the PJM planning year, and shall remain in effect until either party provides to the other at least 30 days' written notice prior to the start of the registration period as provided for in the PJM Tariff for the next planning year of its intention to discontinue service under the terms of this Rider (registration period ends March 31, 2010 for the 2010/11 delivery year). However, this rider shall only be available through May 31, 2012.

SPECIAL TERMS AND CONDITIONS.

Individual customer information, including, but not limited to, ECS Contract Capacity and Curtailment Option, shall remain confidential.

If a new peak demand is set by the customer in the hour following the curtailment, due to the customer resuming the level of activity prior to the curtailment, the customer's previous high demand will be adjusted to disregard that new peak. (N)

RIDER E.P.C.S.
(Energy Price Curtailable Service Rider) (T)

AVAILABILITY OF SERVICE.

Available for Energy Price Curtailable Service (EPCS) to customers normally taking firm service under Tariffs M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D.,Q.P. and C.I.P.- T.O.D. for their total capacity requirements from the Company. The Customer must have an on-peak curtailable demand not less than 100 KW and will be compensated for 100 KW curtailed under the provisions of this Rider. (T)

CONDITIONS OF SERVICE.

1. The Company reserves the right to curtail service to the Customer's EPCS load at the Company's sole discretion. (T)

2. The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the Customer's EPCS load shall be curtailed within 1 (one) hour if so requested. (T)

3. For purposes of this Rider, seasons are defined as follows:

Winter	December, January and February
Spring	March, April and May
Summer	June, July and August
Fall	September, October and November

4. The Company and the Customer shall mutually agree upon the method which the Company shall use to notify the Customer of a curtailment under the provisions of this Rider. The method shall specify the means of communicating such curtailment (e.g., the Company's customer communication system, telephone, pager) and shall designate the Customer's representatives to receive said notification. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company. (T)

5. No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System 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.

6. The Company reserves the right to test and verify the Customer's ability to curtail. Such test will be limited to one curtailment per contract term. Any failure of the customer to comply with a request to curtail load will entitle the Company to call for one additional test. The Company agrees to notify the Customer as to the month in which the test will take place, and will consider avoiding tests on days, which may cause a unique hardship to the Customer's overall operation. There shall be no credits for test curtailments nor charge for failure to curtail during a test.

7. Upon receiving a curtailment notice from the Company, the customer must respond within 45 minutes when the request is made on a day-ahead basis and within 15 minutes when a request is made for the current day if the customer intends to participate in the curtailment event. Customers who fail to respond, or respond that they will not participate in the curtailment event, will receive no payments, nor be subject to any monetary charges described elsewhere under this Rider. However, a customer's failure to respond or a response that the customer will not participate will be considered as a failure to curtail for purposes of Paragraph 8 below. (T)

8. The Company reserves the right to discontinue service to the Customer under this Rider if the Customer fails to curtail under any circumstances three or more times during a season as requested by the Company. (T)

(Cont'd on Sheet No. 25-2)

RIDER E.P.C.S. (Cont'd)
(Energy Price Curtailable Service Rider) (T)

CONDITIONS OF SERVICE, Continued

9. The Customer shall not receive credit for any curtailment periods in which the Customer's curtailable load is already down for an extended period due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, or any event other than the customer's normal operating conditions. (T)

CURTAILMENT OPTION.

At the time the customer contracts for service under this Rider, the customer shall select one or both of the following Curtailment Notice Types: (T)

Notice Type 1	Day-ahead Notification
Notice Type 2	Current Day Notification

At the time the customer selects one or both types of Notice Types above, the Customer shall also select one of the following Curtailment Limits for each Notice Type selected:

	Maximum Duration
Option A	2 hours
Option B	4 hours
Option C	8 hours

The Curtailment Limit is the maximum number of hours per curtailment event for which load may be curtailed under the provisions of this Rider. The Customer shall receive credit for a minimum of 2 (two) hours per curtailment event, even if the event is shorter than two hours. (T)

The Customer shall specify the Maximum Number of Days during the season that the Customer may be requested to curtail under each Notice Type chosen. The Customer shall also specify the Minimum Price at which the customer would be willing to curtail under each Notice Type chosen. The Company, at its discretion will determine whether the Customer shall be curtailed give the Customer's specified Curtailment Options. (T)

EPCS CONTRACT CAPACITY.

Each Customer shall have an EPCS Contract Capacity to be considered as price curtailable capacity under this Rider. The Customer shall specify the Non-EPCS Demand, which shall be the demand at or below which the Customer will remain during curtailment periods. The EPCS Contract Capacity shall be the difference between the Customer's typical on-peak demand and the Customer's specified Non-EPCS Demand. The Company shall determine the Customer's typical on-peak demand, as agreed upon by the Company and the Customer. For the purpose of this Rider, the on-peak billing period is defined as 7:00 a.m. to 11:00 p.m., local time, for all weekdays, Monday through Friday. (T)

The Customer may modify the amount of EPCS Contract Capacity and/or the Curtailment Options no more than once prior to each season. Modifications must be received by the Company in writing no later than 30 days prior to the beginning of the season. (T)

CURTAILED DEMAND.

For each curtailment period, Curtailed Demand shall be defined as the difference between the Customer's typical on-peak demand and the maximum 15-minute integrated demand during each interval of the curtailment period. (T)

(Cont'd on Sheet No. 25-3)

RIDER E.P.C.S. (Cont'd)
(Energy Price Curtailable Service Rider) (T)

CURTAILMENT CREDIT.

Hourly PCS Energy shall be defined as the sum of the Curtailed Demand for each 15-minute interval of the hour divided by four (4). The Curtailment credit shall be equal to the product of the Hourly EPCS Energy and the greater of the following: (a) 80% of the AEP East Load Zone Real-Time Locational Marginal Price (LMP) established by PJM (including congestion and marginal losses) (b) the Minimum Price as specified by the Customer or (c) 3.5 cents/kWh. (T)

MONTHLY CREDIT.

The Monthly Credit shall be equal to the product of the PCS Energy and the applicable Curtailment Option Credit less any Noncompliance Charges. The Monthly Credit will be provided to the Customer by check within 30 days after the end of the month in which the curtailment occurred. This amount will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identify of this cost is preserved. (T)

NONCOMPLIANCE CHARGES

If the Customer responds affirmatively that it will participate in a curtailment event, and subsequently fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Demand shall be the difference between the maximum 15-minute integrated demand during each hour of the curtailment period and the Non-EPCS Demand. Noncompliance Demand shall be billed at a rate equal to the applicable Curtailment Credit for the hours during which the Customer failed to fully comply. (T)

TERM.

Contracts under this Rider may be made for an initial period of one (1) season and shall remain in effect thereafter until either party provides to the other at least 30 days' written notice prior to the start of the next season of its intention to discontinue service under the terms of this Rider.

SPECIAL TERMS AND CONDITIONS.

Individual Customer information, including, but not limited to, EPCS Contract Capacity and Curtailment Options, shall remain confidential. (T)

If a change in metering equipment or functionality is required, customers taking service under this Rider shall pay the additional cost of installation. The Company will make available to the customer the real time pulse metering data, if requested by the customer, for an additional fee. (T)

TARIFF N.U.G.
(Non-Utility Generator)

AVAILABILITY OF SERVICE.

This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intend to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Commissioning Power, Startup Power and/or Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by customer's generator.

DEFINITIONS.

1. **Commissioning Power** - The electrical energy and capacity supplied to the customer prior to the commercial operation of the customer's generator, including initial construction and testing phases.
2. **Station Power** - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the customer's generation facilities, usually when the customer's generator is not operating. Station Power does not include Startup Power.
3. **Startup Power** - The electrical energy and capacity supplied to the customer following a planned or forced outage of the customer's generator for the purpose of returning the customer's generator to synchronous operation.

COMMISSIONING POWER SERVICE.

Customers requiring Commissioning Power shall take service under Tariff T.S. or by special agreement with the Company.

The Customer shall coordinate its construction and testing with the Company to ensure that the customer's operations do not cause any undue interference with the Company's obligations to provide service to its other customers or impose a burden on the Company's system or any system interconnected with the Company.

STATION POWER SERVICE.

Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

STARTUP POWER SERVICE.

Customers requiring Startup Power have the option of contracting for such service under the terms of this tariff or under the generally available demand-metered tariff appropriate for the customer's Startup Power requirements.

Startup Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Startup Power requirements that the Company is expected to supply.

Startup Duration – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.

Startup Frequency – The Customer shall contract for a definite number of startup events sufficient to meet the maximum number of times per year that the Company is expected to supply Startup Power.

Other Startup Characteristics – The customer shall provide to the Company other information regarding the customer's Startup Power requirements, including, but not limited to, anticipated time-of-use and seasonal characteristics.

Notification Requirement - Whenever Startup Power is needed, the Customer shall provide advance notice to the Company.

(Cont'd on Sheet No. 26-2)

KENTUCKY POWER COMPANY

Original Sheet No. 26-2
Canceling ________ Sheet No. 26-2

PSC ELECTRIC NO. 9

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

STARTUP POWER SERVICE. (cont'd)

Upon receipt of a request from the Customer for Startup Power Service under the terms of this tariff, the Company will provide the Customer a written offer containing the Notification Requirement, generation rates (including demand and energy charges) and related terms and conditions of service under which service will be provided by the Company. Such offer shall be based upon the Startup Contract Capacity, Startup Duration, Startup Frequency, and Other Startup Characteristics as specified by the customer. In no event shall the generation rates be less than the sum of the Tariff C.I.P.-T.O.D. Energy Charge, the Fuel Adjustment Clause, the System Sales clause, the Demand-Side Management Adjustment Clause, Environmental Surcharge and the Capacity Charge. (T)

If the parties reach an agreement based upon the offer provided to the customer by the Company, a contract shall be executed that provides full disclosure of all rates, terms and conditions of service under this tariff, and any and all agreements related thereto.

Monthly Transmission and Distribution Rates

	Service Voltage	
	Subtransmission	Transmission
Tariff Code	392	393
Reservation Charge per kW	~~$4.16~~ *$4.74*	~~$2.31~~ *$3.00*

(I)

Reactive Demand Charge for each kiloVAR of maximum leading or lagging reactive demand in excess of 50% of the KW of monthly metered demand...~~$ 0.67~~ *$0.76* per KVAR (I)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

MONTHLY BILLING DEMAND.

The monthly billing demand in kW shall be taken each month as the highest single 15-minute integrated peak in kW as registered by a demand meter or indicator, less the Station Contract Capacity. The monthly billing demand so established shall in no event be less than the greater of (a) the Startup Contract Capacity or b) the customer's highest previously established monthly billing demand during the past 11 months.

MONTHLY BILLING ENERGY.

Interval billing energy shall be measured each 15-minute interval of the month as the total KWH registered by an energy meter or meters less the quotient of the Station Contract Capacity and four (4). In no event shall the interval billing energy be less than zero (0). Monthly billing energy shall be the sum of the interval billing energy for all intervals of the billing month.

(Cont'd on Sheet No. 26-3)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY AFFAIRS FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

TRANSMISSION SERVICE.

Transmission Provider – The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Should the Transmission Provider implement charges for Transmission Congestion, the Company shall provide 30 days written notice to the customer. Upon the expiration of such notice period, should the customer's use of Startup Power result in any charges for Transmission Congestion from the Transmission Provider, such charges, including any applicable taxes or assessments, shall be paid by or passed through to the customer without markup. Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Startup and Station Power from commonly owned generation facilities that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

TARIFF N.M.S.
(Net Metering Service)

AVAILIBILITY OF SERVICE.

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer-generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than thirty (30) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

METERING.

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

BILLING/MONTHLY CHARGES.

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

(Cont'd on Sheet No. 27-2)

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

APPLICATION AND APPROVAL PROCESS.

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

LEVEL 1 AND LEVEL 2 DEFINITIONS.

LEVEL 1
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

(Cont'd on Sheet No. 27-3)

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

LEVEL 1, continued

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

LEVEL 2

A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

(Cont'd on Sheet No. 27-4)

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

LEVEL 2, continued

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

APPLICATION, INSPECTION AND PROCESSING FEES.

No application fees or other review, study, or inspection or witness test fees will be charged by the Company for Level 1 Applications.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $100. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

(Cont'd on Sheet No. 27-5)

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION.

To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 27-6)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 27-7)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-8)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E. K. WAGNER, NAME — DIRECTOR REGULATORY SERVICES, TITLE — FRANKFORT, KENTUCKY, ADDRESS

Issued by authority of an Order by the Public Service Commission in Case No. 2009-00459 dated ________

TARIFF N.M.S.
(Net Metering Service)

TERM OF CONTRACT.

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

(Cont'd on Sheet No. 27-9)

TARIFF N.M.S.
(Net Metering Service)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 30 kW generation capacity and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

Terry Hemsworth
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
tlhemsworth@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name: ____

Mailing Address: ______________________________________

City: ________________________ State: __________ Zip: __________

Phone: (___) ________________ Phone: (___) ________________

E-mail address: ______________________________________

Service Location

Street Address: ______________________________________

City: ________________________ State: __________ Zip: __________

Electric Service Account Number: ________________________

Alternate Contacts

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Name	Company	Telephone/Email

(Cont'd on Sheet No. 27-10)

TARIFF N.M.S.
(Net Metering Service)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: ________________________ Model: ________________________

Inverter Power Rating: ________________________ Voltage Rating: ________________________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ________________________

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating: ________________________

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ________________________

(Cont'd on Sheet No. 27-11)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1:

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(Cont'd on Sheet No. 27-12)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(Cont'd on Sheet No. 27-13)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-14)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: ______________________________ **Date:** _______________

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.

Call: _________________ to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

____

Approved by: ______________________________ **Date:** _______________

Printed Name: ______________________________ **Title:** _______________

(Cont'd on Sheet No. 27-15)

TARIFF N.M.S.
(Net Metering Service)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 30kW generation).

Submit this Application (along with the application fee of $100) to:

Terry Hemsworth
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
tlhemsworth@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name: ____

Mailing Address: ____

City: ______________________ State: __________ Zip: __________

Project Contact Person: ____

Phone: (___) ______________________ Phone: (___) ______________________

E-mail Address: ____

Service Location

Street Address: ____

City: ______________________ State: __________ Zip: __________

Electric Service Account Number: ____

Alternate Contacts

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Name	Company	Telephone/Email

(Cont'd on Sheet No. 27-16)

TARIFF N.M.S.
(Net Metering Service)

APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: ______________________________

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

(Cont'd on Sheet No. 27-17)

TARIFF N.M.S.
(Net Metering Service)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ____________, 20___, by and between Kentucky Power Company (Company), and ________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: ____

Generator Size and Type: ____

Now, Therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

(Cont'd on Sheet No. 27-18)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1 Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 27-19)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6 Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 27-20)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-21)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: ______________________ **Date:** ______________

Printed Name: ______________________ **Title:** ______________

Company Signature: ______________________ **Date:** ______________

Printed Name: ______________________ **Title:** ______________

(Cont'd on Sheet No. 27-22)

TARIFF N.M.S.
(Net Metering Service)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

KENTUCKY POWER COMPANY

Original Sheet No. 28-1
Canceling ______ Sheet No. 28-1

P.S.C. ELECTRIC NO.9

TARIFF C.C.
(Capacity Charge)

AVAILABILITY OF SERVICE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S.,L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L. and S.L. (T)

RATE.

	Service Tariff		
	All Other	C.I.P.-T.O.D.	
Energy Charge per KWH per month	~~$0.000824~~ *$ 0.000970*	~~$0.000508~~ *$0.000667*	(I)

RATE CALCULATION.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2004-00420 and the Settlement and Stipulation Agreement dated October 20, 2004 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the supplemental annual payments tied to the 18-year extension of the Rockport Unit Power Service Agreement (UPSA). Kentucky Power will apply surcharges designed to enable recovery from each tariff class of customers, an annual supplemental payment of $5.1 million annually in Years 2005 through 2009, and then increases to $6.2 million annually in Years 2010 through 2021, and then decreases to $5,792,329 in Year 2022.

2. Kentucky Power will be entitled to receive these annual supplemental payments in addition to the base retail rates established by the Commission. The costs associated with the underlying Rockport Unit 1 and 2 UPSA will continue to be included in base rates.

3. The increased annual revenues will be generated by two different KWH rates, one for CIP-TOD tariff customers and one for All Other tariff customers.

4. The allocation of the additional revenues to be collected from the CIP-TOD tariff customers and All Other tariff customers will be based upon the total annual revenue of each of the two-customer classes. Once the additional revenues have been allocated between the two customer classes based upon total annual Kentucky retail revenue, the additional revenue will be collected within the two customer classes (CIP-TOD and All Other tariffs) on a KWH basis. The KWH rate to be applied to each of these two customer class groups shall be sufficient to generate that portion of the total increase in annual revenues equal to the percentage of total annual revenues produced by each of the two customer class groups (CIP-TOD and All Other tariffs).

5. The Stipulation and Settlement Agreement is made upon the express agreement by the Parties that the receipt by Kentucky Power of the additional revenues called for by Section III(1)(a) and III(1)(b) shall be accorded the ratemaking treatment set out in Section III. In any proceeding affecting the rates of Kentucky Power during the extension of the UPSA under this Stipulation and Settlement Agreement, the provisions of Section III are an express exception to Section VI(4) of the Stipulation and Settlement Agreement.

6. The Capacity Charge factors will be applied to bills monthly and will be shown on the Customer's bill as a separate line item.

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY	E.K. WAGNER	DIRECTOR OF REGULATORY SERVICES	FRANKFORT, KENTUCKY
	NAME	TITLE	ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

KENTUCKY POWER COMPANY

Original Sheet No. 29-1
Canceling ______ Sheet No. 29-1

P.S.C. ELECTRIC NO. 9

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.- I.R.P., M.W., O.L., and S.L. (T)

RATE.

1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, excluding revenues under the Transmission Adjustment equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 3 below and in the current period according to the following formula:

$$\text{Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

KY Retail R(m) = Kentucky Retail Revenues for the Expense Month, excluding Transmission Adjustment Revenues. (T)

2. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

$$E(m) = CRR - BRR$$

Where:

CRR = Current Period Revenue Requirement for the Expense Month.

BRR = Base Period Revenue Requirement.

3. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs	
JANUARY	$ ~~2,531,784~~	*$ 3,991,163* (I)
FEBRUARY	~~3,003,995~~	*$ 3,590,810*
MARCH	~~2,845,066~~	*$ 3,651,374*
APRIL	~~2,095,535~~	*$ 3,647,040*
MAY	~~1,514,859~~	*$ 3,922,590*
JUNE	~~1,913,578~~	*$ 3,627,274*
JULY	~~2,818,212~~	*$ 3,805,325*
AUGUST	~~2,342,883~~	*$ 4,088,830*
SEPTEMBER	~~2,852,305~~	*$ 3,740,010*
OCTOBER	~~2,181,975~~	*$ 3,260,302*
NOVEMBER	~~2,598,522~~	*$ 2,786,040*
DECEMBER	~~1,407,969~~	*$ 4,074,321*
	~~$28,106,683~~	*$44,185,079* (I)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2009-00459 dated

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

4. Current Period Revenue Requirement, CRR

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)})(ROR_{IM(c)})/12) + OE_{IM(c)}] (.15) - AS]$$

Where:

$RB_{KP(C)}$	=	Environmental Compliance Rate Base for Big Sandy.
$ROR_{KP(C)}$	=	Annual Rate of Return on Big Sandy Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{KP(C)}$	=	Monthly Pollution Control Operating Expenses for Big Sandy.
$RB_{IM(C)}$	=	Environmental Compliance Rate Base for Rockport.
$ROR_{IM(C)}$	=	Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{IM(C)}$	=	Monthly Pollution Control Operating Expenses for Rockport.
AS	=	Net proceeds from the sale of SO_2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. The SO_2 allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations.

"KP(C)" identifies components from the Big Sandy Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period.

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan and the 2003 Plan. The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan and the 2007 Plan.

The Rate of Return for Kentucky Power is 10.5% rate of return on equity as authorized by the Commission in its March 14, 2006 Order in Case No. 2005-00341 at page 12.

(Cont'd on Sheet No. 29-3)

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

5. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

(a) cost associated with Continuous Emission Monitors (CEMS)

(b) costs associated with the terms of the Rockport Unit Power Agreement

(c) the Company's share of the pool capacity costs associated with Gavin scrubber(s)

(d) return on SO_2 allowance inventory

(e) costs associated with air emission fees

(f) over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge

(g) costs associated with any Commission's consultant approved by the Commission

(h) costs associated with Low Nitrogen Oxide (NO_x) burners at the Big Sandy Generating Plant

(i) costs associated with the consumption of SO_2 allowances

(j) costs associated with the Selective Catalytic Reduction (SCR) at the Big Sandy Generating Plant

(k) costs associated with the upgrade of the precipitator at the Big Sandy Generating Plant

(l) costs associated with the over-fire air with water injection at the Big Sandy Generating Plant

(m) costs associated with the consumption of NO_x allowances

(n) return on NO_x allowance inventory

(o) 25% of the costs associated with the Reverse Osmosis Water System (the amount is subject to adjustment at subsequent 6 month surcharge reviews based on the documented utilization of of the RO Water System by the SCR)

(p) costs associated with operating approved pollution control equipment

(Cont'd on Sheet No. 29-4)

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

(q) costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)

(r) the Company's share of the pool Capacity costs associated with the following:

- Amos Unit No. 3 CEMS, Low NO_x Burners, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Cardinal Unit No 1 CEMS, Low NO_x Burners, SCR, Catalyst Replacement, FGD, Landfill and SO_3 Mitigation
- Gavin Plant SCR and SCR Catalyst Replacement
- Gavin Unit No 1 and 2 Low NO_x Burners and SO_3 Mitigation
- Kammer Unit Nos 1, 2 and 3 CEMS, Over Fire Air and Duct Modification
- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsom Material Handling Facilities
- Muskingum River Unit No 1 Low NO_x Ductwork, Over Fire Air , Over Fire Air Modification, Water Injection and Water Injection Modification
- Muskingum River Unit No 2 Low NO_x Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection
- Muskingum River Unit No 3 Over Fire Air, Over Fire Air Modification with NO_x Instrumentation
- Muskingum River Unit No 4 Over Fire Air with Modification
- Muskingum River Unit No 5 Low NO_x Burner with Modification and Weld Overlay, an SCR and SO3 Mitigation
- Muskingum River Common CEMS
- Phillip Sporn Unit No 2 Low NO_x Burners with Modifications
- Phillip Sporn Unit No 4 and 5 Low NO_x Burners and Modulating Injection Air system with Modifications
- Phillip Sporn Common CEMS, SO_3 Injection System and Landfill
- Rockport Unit No 1 and 2 Low NO_x Burners and Landfill

(Cont'd on Sheet No. 29-5)

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

- Tanners Creek Unit No 1 Low NO_x Burners, with Modifications and Low NO_x Burners Leg Replacement
- Tanners Creek Unit No 2 and 3 Low NO_x Burners with Modifications
- Tanners Creek Unit No 4 Over Fire Air, Low NO_x Burners and ESP Controls Upgrade
- Tanners Creek Common CEMS and Coal Blending Facilities
- Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Phillip Sporn, Rockport and Tanners Creek plants.

6. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

TARIFF R.T.P.
(Experimental Real-Time Pricing Tariff)

AVAILABILITY OF SERVICE.

Available for Real-Time Pricing (RTP) service, on an experimental basis, to customers normally taking firm service under Tariffs Q.P. or C.I.P.-T.O.D. *for their total capacity requirements from the Company. The customer will pay real-time prices* for load in excess of an amount designated by the customer. This experimental tariff will be limited to a maximum of 10 customers. The incremental cost of any special metering or communications equipment required for service under this experimental tariff beyond that normally provided under the applicable standard Q.P. or C.I.P.-T.O.D. tariff shall be borne by the customer. The Company reserves the right to terminate this Tariff at any time after the end of the experiment.

PROGRAM DESCRIPTION.

The Experimental Real-Time Pricing Tariff is voluntary and will be offered on a pilot basis for a three-year period. The RTP Tariff will offer customers the opportunity to manage their electric costs by shifting load from higher cost to lower cost pricing periods or by adding new load during lower price periods. The experimental pilot will also offer the customer the ability to experiment in the wholesale electricity market by designating a portion of the customer's load subject to standard tariff rates with the remainder of the load subject to real-time prices. The designated portion of the customer's load is billed under the Company's standard Q.P. or C.I.P.-T.O.D. tariff. The remainder of the customer's capacity and energy load is billed at prices established in the PJM Interconnection, L.L.C. (PJM) RTO market.

CONDITIONS OF SERVICE.

The customer must have a demand of not less than 1 MW and specify at least 100 kW as being subject to this Tariff. The customer designates the maximum amount of load to be supplied by Kentucky Power Company under the applicable Tariff Q.P. or Tariff C.I.P. – T.O.D. *All usage equal to or less than the customer-designated level of load will be billed under the* appropriate Tariff Q.P. or Tariff C.I.P. – T.O.D. All usage in excess of the customer-designated level will be billed under Tariff RTP. All reactive demand shall be billed in accordance with the appropriate Tariff Q.P. or Tariff C.I.P. – T.O.D.

RATE.

1. Capacity Charge.

The Capacity Charge, stated in \$/kW, will be determined from the auction price set in the Reliability Pricing Model (RPM) auction held by PJM for each PJM planning year. The auction price will be adjusted by the class average diversity factor (DF) derived from billing demands for the preceding year and the 5 highest coincident peaks established for the class at the time of the 5 highest PJM hourly values. The price will be further adjusted for demand losses (DL) and a factor to reflect the PJM-required reserve margin (RM).

Capacity Charge = RPM x DF x DL x RM

Where:
RPM =Results of the annual RPM auction price applicable to the AEP load zone = ~~\$3.404~~/ *\$5.301*/kW-month (I)
DF = Diversity Factor
C.I.P. – T.O.D. = ~~0.83~~ *\$0.72* (R)
Q.P. = ~~0.68~~ *\$0.72* (I)
DL = Demand Loss Factor
RM = Reserve Margin = RPM clearing price reserve margin = ~~1.175~~ *1.165* (R)

(Cont'd on Sheet No. 30-2)

TARIFF R.T.P.
(Experimental Real-Time Pricing Tariff)

RATE (continued).

2. Energy Charge.

The Energy Charge, stated in $/KWH, will be determined hourly using the AEP East Load Zone Real-Time Locational Marginal Price (LMP) established by PJM (including marginal losses), adjusted for energy losses (EL). The charge will be applied to the usage in excess of the customer-designated level for each billing period.

Energy Charge = LMP x EL

Where:
LMP = AEP East Load Zone Real-Time Locational Marginal Price
EL = Energy Loss Factor excluding marginal losses for transmission and subtransmission

3. Transmission Charge.

The Transmission Charge, stated in $/kW, will be determined from the Network Integration Transmission Service (NITS) rate for the AEP East Zone. The NITS rate will be adjusted by the class average diversity factor (DF) derived from billing demands for the preceding year and the coincident peak established for the class at the time of the highest AEP East Zone hourly value. The price will be further adjusted for demand losses (DL).

Transmission Charge = NITS x DF x DL

Where:
NITS = NITS Rate for the AEP East Zone = $~~1.7574~~ / *2.1116*/kW (I)
DF = Diversity Factor
C.I.P. – T.O.D. = ~~0.83~~ *0.66* (R)
Q.P. = ~~0.67~~ *0.63* (R)
DL = Demand Loss Factor

4. Other Market Services Charge.

The Other Market Services Charge, stated in $/KWH is developed using all other PJM related market costs allocated to Kentucky Power Company from PJM not captured elsewhere. It is applied to all usage in excess of the customer-designated level for each billing period.

Secondary = ~~$0.002915~~ /*$0.002499/KWH* (R)
Primary = ~~$0.002842~~ /*$0.002404/KWH* (R)
Subtransmission = $~~0.002800~~ /*$0.002359/KWH* (R)
Transmission = $~~0.002765~~ /*$0.002337/KWH* (R)

5. Distribution Charge.

The Distribution Charge, stated in $/kW, is equivalent to the distribution portion of the current rates included in Tariff Q.P. and Tariff C.I.P. – T.O.D.

Secondary = $~~4.46~~ / *$7.97*/kW (I)
Primary = $~~2.77~~ / *$4.72*/kW (I)

(Cont'd on Sheet No. 30-3)

TARIFF R.T.P.
(Experimental Real-Time Pricing Tariff)

RATE (continued).

6. Program Charge.

The Program Charge is $150 per month for billing, administration and communications required to implement and administer the Experimental Real-Time Pricing Tariff.

7. Riders.

Bills rendered under this Tariff for RTP usage shall be subject to any current or future non-generation related riders.

A customer's total bill shall equal the sum of the RTP bill for all usage in excess of the customer-designated level and the standard tariff bill for usage equal to or below the designated level.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (T)

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered kWh and kW values will be adjusted for billing purposes. If the Company elects to adjust kWh and kW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered during the month by a demand meter. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity set forth on the contract for electric service or (b) the customer's highest previously established monthly billing demand during the past 11 months. The RTP monthly billing demand shall be the customer's monthly billing demand in excess of the customer-designated level.

TERM.

Customers who participate in this experimental tariff are required to enter into a written service agreement. Customer participation will coincide with the PJM planning year which runs from June 1 through May 31. Customers must enroll by May 15 of each year to begin service on June 1 and must stay with the service for the entire planning year. Customers who choose not to re-enroll in the program are ineligible to return to the program. No additional customers will be placed under this tariff after June 1, 2010.

(Cont'd on Sheet No. 30-4)

TARIFF R.T.P.
(Experimental Real-Time Pricing Tariff)

TRANSFORMER AND LINE LOSSES.

Demand losses will be applied to the Capacity and Transmission Charges using the following factors:

Secondary = ~~1.09752~~ *1.10221* (I)
Primary = ~~1.06908~~ *1.06570* (R)
Subtransmission = ~~1.04605~~ *1.04278* (R)
Transmission = ~~1.03056~~ *1.03211* (I)

Energy losses will be applied to the Energy Charge using the following factors:

Secondary = ~~1.05938~~ *1.06938* (I)
Primary = ~~1.03361~~ *1.02972* (R)
Subtransmission = ~~1.01667~~ *1.00954* (R)
Transmission = ~~1.01310~~ *1.00577* (R)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

A customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by customer. When the size of the customer's load necessitates the delivery of energy to the customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customers with PURPA Section 210 *qualifying cogeneration and/or small power production facilities* shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

RIDER G.P.O.
(Green Pricing Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.-I.R.P. and M.W. tariffs. (T)

Participation in this program may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

CONDITIONS OF SERVICE.

Customers who wish to support the generation of electricity by Renewable Resources may contract to purchase each month a specific number of fixed kWh blocks, where each block equals 100 kWh. Customers may elect to purchase a minimum of one (1) block per month and a maximum of 500 blocks per month.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. Only Renewable Resources brought into service on or after January 1, 1997 shall qualify.

RATE.

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for each fixed kWh block under contract regardless of the customer's actual energy consumption during that month. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

Charge ($ per 100 kWh block): $ 2.00/month

TERM.

This is a voluntary program. Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable.

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Green Pricing Option Rider will be used solely to purchase RECs for the program.

RIDER A.F.S.
(Alternate Feed Service Rider)

AVAILABILITY OF SERVICE.

(N)

Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S., M.G.S. TOD, L.G.S., L.G.S.-TOD, Q.P., C.I.P. TOD, or M.W. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

SYSTEM IMPACT STUDY CHARGE.

The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

EQUIPMENT AND INSTALLATION CHARGE.

The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

TRANSFER SWITCH PROVISION.

In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety. (N)

(Cont'd on Sheet No. 32-2)

RIDER A.F.S.
(Alternate Feed Service Rider)

TRANSFER SWITCH PROVISION (continued). (N)

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $13.57 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

MONTHLY AFS CAPACITY RESERVATION DEMAND CHARGE.

Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $4.72 per kW.

AFS CAPACITY RESERVATION.

The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's normal maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement. (N)

(Cont'd on Sheet No. 32-3)

RIDER A.F.S.
(Alternate Feed Service Rider)

AFS CAPACITY RESERVATION (continued). (N)

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify AEP regarding any reduction in the AFS capacity reservation.

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

DETERMINATION OF BILLING DEMAND.

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. (N)

(Cont'd on Sheet No. 32-4)

RIDER A.F.S.
(Alternate Feed Service Rider)

TERMS OF CONTRACT. (N)

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

SPECIAL TERMS AND CONDITIONS.

This rider is subject to the Company's Terms and Conditions of Service.

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason. (N)

U.G.R.T.
(Utility Gross Receipts Tax)
(School Tax)

(N)

APPLICABLE.

To all Tariff Schedules.

RATE.

This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

(N)

K.S.T.
(Kentucky Sales Tax)

(N)

APPLICABLE.

To all Tariff Schedules.

RATE.

This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(8). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

(N)

TARIFF T.A.
(Transmission Adjustment) (N)

AVAILABILITY OF SERVICE.

To Tariffs R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D., R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., Experimental M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.- I.R.P., and M.W.

RATE.

The Transmission Adjustment shall provide for annual adjustments to rates based on a rate which is a percent of revenues, excluding revenues under the Environmental Surcharge, as follows:

	Transmission Adjustment Factor (T.A.F.)	Balancing Adjustment Factor (B.A.F.)
Factor: % of Total Bill	-1.12942%	0%

RATE CALCULATION.

1. The Transmission Adjustment shall provide for annual adjustments based on a percent of revenues, excluding revenues under the Environmental Surcharge, equal to the difference between the transmission costs in the base period as provided in Paragraph 3 below and in the current period according to the following formula:

$$\text{Transmission Adjustment Factor} = \frac{\text{KY Retail T(a)}}{\text{KY Retail R(a)}}$$

Where:

KY Retail T(a) = Annual T(a) for Kentucky Retail Customers.

KY Retail R(a) = Kentucky Retail Revenues for the Expense Year, excluding Environmental Surcharge revenues.

2. Transmission Adjustment Annual Gross Revenue Requirement, T(a)

$$T(a) = CTRR - BTRR$$

Where:

CTRR = Current Period Transmission Revenue Requirement for the Expense Year, (Kentucky Retail Share of Total Company Expenses).

BTRR = Base Period Transmission Revenue Requirement.

3. Base Period Transmission Revenue Requirement, BTRR

BTRR = The annual amount of $49,514,393 for Kentucky Retail Customers. (N)

(Cont'd on Sheet No. 35-2)

DATE OF ISSUE December 29, 2009 DATE EFFECTIVE Service rendered on and after January 29, 2010

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

TARIFF T.A. Cont'd
(Transmission Adjustment)

(N)

4. Current Period Transmission Revenue Requirement, CTRR

CTRR = NITS – RC + RTO + TOA + ECRC + PJMA + TEC

Where:

NITS = Network Integration Transmission Service Charges (Attachment H-14).

RC = Revenue Credits (Attachment H-14).

RTO = RTO start-up costs (Attachment H-14).

TOA = Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A).

ECRC = Expansion Cost Recovery Charge (Schedule 13).

PJMA = PJM Administrative Charges (Schedules 9 and 10).

TEC = Transmission Enhancement Charges (Schedule 12).

5. The Transmission Adjustment Factor shall be based upon estimated annual revenues and costs, subject to subsequent adjustment through the Balancing Adjustment Factor upon final determination of actual revenues and costs.

6. The Balancing Adjustment Factor will reconcile any over-, or under-recovery of transmission costs from prior periods. The Balancing Adjustment Factor will be in effect for the second through twelfth months of the subsequent annual period. The Balancing Adjustment Factor will be determined by dividing the difference between the actual amounts charged or credited in the prior period and the actual amounts that should have been charged or credited in the prior period by the expected Kentucky Retail Revenues, excluding Environmental Surcharge revenues.

7. The Transmission Adjustment Factor and Balancing Adjustment Factor shall be filed with the Commission thirty (30) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the factor, which shall include data and information as may be required by the Commission.

8. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. (N)

Kentucky Power Company
Analysis of Reconnect Charges

Line No.	Description	Reconnect Regular Hours - Day Shift (1)	Reconnect Into O. T. Hours - Day Shift (2)	Reconnect Call-Out Hours - Day Shift (3)	Reconnect Sunday/ Holidays - Day Shift (4)	Collection Trip Charge (5)	Bad Check Charge (6)	Meter Test Charge (7)	Total Additional Revenues (8)
1	Hours Worked	1.0	1.0	2.0	2.0	0.6	0.0	1.5	
2	Transportation Hours	1.0	1.0	0.8	0.8	0.6	0.0	1.5	
3	Hourly Labor Rate	22.63	22.63	22.63	22.63	22.63	0.00	25.95	
4	Overtime Adj.	0.00	11.32	11.32	22.63	0.00	0.00	0.00	
5	Hourly Labor Rate W/O.T.	22.63	33.95	33.95	45.26	22.63	0.00	25.95	
6	Labor Cost (Line 1 * Line 5)	22.63	33.95	67.90	90.52	13.58	2.25	38.93	
7	Transportation Hourly Rate	8.74	8.74	8.74	8.74	8.74	0.00	8.74	
8	Trans. Cost (Line 7 * Line 2)	8.74	8.74	6.99	6.99	5.24	0.00	13.11	
9	Fringe Benefits Rate	0.4105	0.1135	0.1135	0.1135	0.4105	0.4105	0.4105	
10	Benefits Cost (Line 6 * Line 9)	9.29	3.85	7.71	10.27	5.57	0.92	15.98	
11	Bank Fees						3.54		
12	Total Cost (Line 6 + Line 8 + Line 10 = Line 12)	40.66	46.54	82.60	107.78	24.39	6.71	68.02	
13	Suggested Charge	40.00	47.00	83.00	108.00	24.00	7.00	68.00	
14	Current Charge	12.94	17.26	35.95	44.58	8.63	7.00	14.38	
15	increase/(Decrease)	27.06	29.74	47.05	63.42	15.37	0.00	53.62	
16	12 Month 9/30/09 Actual No. of Trans.	10,970	775	539	32	28,162	1,958	28	
17	Total Additional Revenues	$296,848	$23,049	$25,360	$2,029	$432,850	$0	$1,501	$781,638
18	Less:State Income Tax at 6.00%								$46,898
19	Less:Federal Tax At 35%								$257,159
20	Net Income Effect								$477,581
21	13 Month Average Equity as of September 30, 2009								$412,359,477
22	Effect on Return on Equity (LN 20/Ln 21)								0.12%

Exhibit EKW-6

Kentucky Power Company
Twelve Months Ending September 3[illegible] [illegible]9
Non-Recurring Charges
Monthly Break Down

Ln No (1)	Description (2)	Oct 08 (3)	Nov 08 (4)	Dec 08 (5)	Jan 09 (6)	Feb 09 (7)	Mar 09 (8)	Apr 09 (9)	May 09 (10)	Jun 09 (11)	Jul 09 (12)	Aug 09 (13)	Sep 09 (14)	Total (15)	Proposed Increase (16)	Proposed Increase Per Class (17)
	$12.94 Reconnect Charge															
1	Residential	1088	753	428	201	518	836	1059	1124	1101	1117	1129	1044	10,398	$27.06	$281,370
2	Commerical	56	50	33	25	37	60	56	53	45	41	54	59	569	$27.06	$15,397
3	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	$27.06	$0
4	Industrial	1	0	1	0	1	0	0	0	0	0	0	0	3	$27.06	$81
5	Total	1145	803	462	226	556	896	1115	1177	1146	1158	1183	1103	10,970		$296,848.00
	$17.26 into Overtime															
6	Residential	90	40	30	24	46	69	77	90	78	55	82	73	754	29.74	$22,424
7	Commerical	3	1	2	0	0	0	4	3	3	2	0	3	21	29.74	$625
8	Total	93	41	32	24	46	69	81	93	81	57	82	76	775		$23,049
	$35.95 Call Out															
9	Residential	50	43	16	5	26	59	49	48	52	44	70	64	526	47.05	$24,748
10	Commerical	1	0	0	0	2	0	2	2	2	1	3	0	13	47.05	$612
11	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	47.05	$0
12	Total	51	43	16	5	28	59	51	50	54	45	73	64	539		$25,360
	$44.58 Sun. Holiday															
13	Residential	1	0	0	0	0	1	12	2	4	7	0	3	30	63.42	$1,903
14	Commerical	0	1	0	0	0	0	0	1	0	0	0	0	2	63.42	$127
15	Total	1	1	0	0	0	1	12	3	4	7	0	3	32		$2,030
	$8.63Collection Trip															
16	Residential	2124	2144	1954	2223	2455	2655	2400	2162	2263	1996	1906	1717	25,999	15.37	$399,605
17	Commerical	186	163	176	140	201	195	168	217	192	151	154	147	2,090	15.37	$32,123
18	Public Authority	0	0	0	0	8	3	6	2	5	0	0	7	31	15.37	$476
19	School	0	0	0	0	0	0	0	0	0	0	0	0	0	15.37	$0
20	Industrial	2	4	4	2	2	5	2	3	0	1	2	2	29	15.37	$446
21	Mine Power	3	0	1	1	3	1	1	0	0	2	0	0	12	15.37	$184
22	ıblic Street Lights	0	0	0	0	0	0	1	0	0	0	0	0	1	15.37	$15
23	Total	2315	2311	2135	2366	2669	2859	2578	2384	2460	2150	2062	1873	28,162		$432,849
	$7.00 Bad Check Charge															
24	Residential	187	93	143	140	122	139	149	178	172	178	149	165	1,815	0.00	$0
25	Commerical	8	21	14	10	9	6	8	10	9	14	16	17	142	0.00	$0
26	Public Authority	0	0	0	0	0	0	0	1	0	0	0	0	1	0.00	$0
27	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	$0
28	Mine Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	$0
29	Total	195	114	157	150	131	145	157	189	181	192	165	182	1,958		$0
	$14.38 Meter Test															
30	Residential	1	0	2	7	6	3	1	0	0	0	2	0	22	53.62	$1,180
31	Commerical	0	0	0	0	3	1	0	0	0	0	0	1	5	53.62	$268
32	Public Authority	1	0	0	0	0	0	0	0	0	0	0	0	1	53.62	$54
33	Total	2	0	2	7	9	4	1	0	0	0	2	1	28		$1,502
34	Total															$781,638.00

Exhibit EKW-7

Kentucky Power Company
Non-Recurring Charges
by Customer Class
September 30 2009

Ln No (1)	Description (2)	Reconnect $40.00 Charge (3)	Reconnect $47.00 Charge (4)	Reconnect $83.00 Charge (5)	Reconnect $108.00 Charge (6)	Collection Trip $24.00 Charge (7)	Bad Check $7.00 Charge (8)	Meter Test $68.00 Charge (9)	Class Revenue increase (10)	Twelve Month Sept. 30, 2009 Billed & Accrued Revenue (11)	Class Total Percent Change (12)
1	Residential	$281,370	$22,424	$24,748	$1,903	$399,605	$0	$1,180	$731,230	$205,219,658	0.3563%
2	Commerical	$15,397	$625	$612	$127	$32,123	$0	$268	$49,152	$89,172,597	0.0551%
3	Public Authority	$0	0	0	0	$476	$0	$54	$530	$15,635,011	0.0034%
4	School	0	0	0	0	$0	0	0	$0	$16,098,247	0.0000%
5	Industrial	$81	0	$0	0	$446	$0	0	$527	$119,162,661	0.0004%
6	Mine Power	0	0	0	0	$184	$0	0	$184	$70,451,900	0.0003%
7	Public Street Lighting	0	0	0	0	$15	0	0	$15	$1,356,795	0.0011%
8	Total	$296,848	$23,049	$25,360	$2,030	$432,849	$0	$1,502	$781,638	$517,096,869	0.1512%

Exhibit EKW-8

Kentucky Power Company
Twelve Months Ending September [illegible]09
Non-Recurring Charges
Monthly Break Down
Test Year Revenues

Ln No (1)	Description (2)	Oct 08 (3)	Nov 08 (4)	Dec 08 (5)	Jan 09 (6)	Feb 09 (7)	Mar 09 (8)	Apr 09 (9)	May 09 (10)	Jun 09 (11)	Jul 09 (12)	Aug 09 (13)	Sep 09 (14)	Total (15)	Test Year Rate (16)	Test Year Revenue Per Class (17)
	$12.94 Reconnect Charge															
1	Residential	1088	753	428	201	518	836	1059	1124	1101	1117	1129	1044	10,398	$12.94	$134,550.12
2	Commerical	56	50	33	25	37	60	56	53	45	41	54	59	569	$12.94	$7,362.86
3	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	$12.94	$0.00
4	Industrial	1	0	1	0	1	0	0	0	0	0	0	0	3	$12.94	$38.82
5	Total	1145	803	462	226	556	896	1115	1177	1146	1158	1183	1103	10,970		$141,951.80
	$17.26 into Overtime															
6	Residential	90	40	30	24	46	69	77	90	78	55	82	73	754	17.26	$13,014.04
7	Commerical	3	1	2	0	0	0	4	3	3	2	0	3	21	17.26	$362.46
8	Total	93	41	32	24	46	69	81	93	81	57	82	76	775		$13,376.50
	$35.95 Call Out															
9	Residential	50	43	16	5	26	59	49	48	52	44	70	64	526	35.95	$18,909.70
10	Commerical	1	0	0	0	2	0	2	2	2	1	3	0	13	35.95	$467.35
11	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	35.95	$0.00
12	Total	51	43	16	5	28	59	51	50	54	45	73	64	539		$19,377.05
	$44.58 Sun. Holiday															
13	Residential	1	0	0	0	0	1	12	2	4	7	0	3	30	44.58	$1,337.40
14	Commerical	0	1	0	0	0	0	0	1	0	0	0	0	2	44.58	$89.16
15	Total	1	1	0	0	0	1	12	3	4	7	0	3	32		$1,426.56
	$8.63Collection Trip															
16	Residential	2124	2144	1954	2223	2455	2655	2400	2162	2263	1996	1906	1717	25,999	8.63	$224,371.37
17	Commerical	186	163	176	140	201	195	168	217	192	151	154	147	2,090	8.63	$18,036.70
18	Public Authority	0	0	0	0	8	3	6	2	5	0	0	7	31	8.63	$267.53
19	School	0	0	0	0	0	0	0	0	0	0	0	0	0	8.63	$0.00
20	Industrial	2	4	4	2	2	5	2	3	0	1	2	2	29	8.63	$250.27
21	Mine Power	3	0	1	1	3	1	1	0	0	2	0	0	12	8.63	$103.56
22	Public Street Lights	0	0	0	0	0	0	1	0	0	0	0	0	1	8.63	$8.63
23	Total	2315	2311	2135	2366	2669	2859	2578	2384	2460	2150	2062	1873	28,162		$243,038.06
	$7.00 Bad Check Charge															
24	Residential	187	93	143	140	122	139	149	178	172	178	149	165	1,815	7.00	$12,705.00
25	Commerical	8	21	14	10	9	6	8	10	9	14	16	17	142	7.00	$994.00
26	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	7.00	$0.00
27	Industrial	0	0	0	0	0	0	0	1	0	0	0	0	1	7.00	$7.00
28	Mine Power	0	0	0	0	0	0	0	0	0	0	0	0	0	7.00	$0.00
29	Total	195	114	157	150	131	145	157	189	181	192	165	182	1,958		$13,706.00
	$14.38 Meter Test															
30	Residential	1	0	2	7	6	3	1	0	0	0	2	0	22	14.38	$316.36
31	Commerical		0	0	0	3	1	0	0	0	0	0	1	5	14.38	$71.90
32	Public Authority	1	0	0	0	0	0	0	0	0	0	0	0	1	14.38	$14.38
33	Total	2	0	2	7	9	4	1	0	0	0	2	1	28		$402.64
34	Total															$433,278.61

Exhibit EKW-9

Kentucky Power Company
Monthly Environmental Costs
for the Twelve Months Ending September 30, 2009

Exhibit EKW-10

Ln No (1)	Month / Year (2)	Monthly Environmental Costs* (3)	Adjustment Due to MLR Change (4)	Adjusted Environmental Base (Col 5 = Cols 3 + 4)
1	October 2008	$3,260,302		$3,260,302
2	November 2008	$2,786,040		$2,786,040
3	December 2008	$4,074,321		$4,074,321
4	January 2009	$3,958,860	$32,303	$3,991,163
5	February 2009	$3,679,280	($88,470)	$3,590,810
6	March 2009	$3,608,706	$42,668	$3,651,374
7	April 2009	$3,645,136	$1,904	$3,647,040
8	May 2009	$3,908,304	$14,286	$3,922,590
9	June 2009	$3,612,903	$14,371	$3,627,274
10	July 2009	$3,748,647	$56,678	$3,805,325
11	August 2009	$4,032,114	$56,716	$4,088,830
12	September	$3,706,347	$33,663	$3,740,010
13	Total	$44,020,960	$164,119	$44,185,079

* Per Monthly ES Form 1.00, Line 1

Kentucky Power Company
Rockport Extension Revenue Allocation
Using the twelve months
ending September 30, 2009 Revenues

Exhibit EKW-11

Ln. No. (1)	Tariffs (2)	Billed Revenues (3)	Percent of Revenue (4)	Allocated $6.2 Million (5)	Twelve Months Ending June 30, 2005 kWh Sales (6)	kWh Rate All Other Customers (7)	kWh Rate CIP-TOD Customers (8)
1	Residential	$201,526,143	39.06%	$2,421,720	2,461,126,114		
2	SGS	$14,827,375	2.87%	$177,940	138,079,811		
3	MGS	$51,696,403	10.02%	$621,240	563,766,758		
4	LGS	$60,551,264	11.74%	$727,880	756,912,077		
5	OL	$6,634,454	1.29%	$79,980	43,442,085		
6	SL	$1,147,595	0.22%	$13,640	8,510,605		
7	MW	$597,910	0.12%	$7,440	7,790,849		
8	QP	$59,150,137	11.46%	$710,520	928,642,221		
9	CIP-TOD	$119,793,891	23.22%	$1,439,640	2,157,679,160		
10	Total	$515,925,172	100.00%	$6,200,000	7,065,949,680		
11	New Rate					$0.000970	$0.000667

Kentucky Power Company
Transmission Agreement Revenues
for the Month September 30, 2009 Revised

Exhibit EKW - 12

Ln No (1)	Company (2)	Original MLR (3)	Revised MLR (4)	Member's Transmission Investment (5)	Member's Transmission Obligation (6)	Member's Transmission Surplus (7)	Member's Transmission Deficit (8)
1	APCo	0.35084	0.35155	$1,269,038,988	$1,215,074,908	$53,964,080	
2	KPCo	0.07069	0.07084	$292,025,873	$244,846,840	$47,179,033	
3	I&M	0.17927	0.17963	$830,436,878	$620,861,630	$209,575,248	
4	OPCo	0.21326	0.21166	$706,592,513	$731,568,071		$24,975,558
5	CSP	0.18594	0.18632	$358,241,714	$643,984,517		$285,742,803
6	Total	1.00000	1.00000	$3,456,335,966	$3,456,335,966	$310,718,361	$310,718,361

Ln No	Company	Monthly Carrying Charge	Transmission Receipts	Transmission Payments
7	APCo	1.4933%	$805,846	
8	KPCo	1.4950%	$705,327	
9	I&M	1.5000%	$3,143,629	
10	OPCo			$374,153
11	CSP			$4,280,649
12	Total		$4,654,802	$4,654,802

Ln No	Company	Recaluated Transmission Receipts	Actual Sept Transmission Receipts	Sept. Difference
13	KPCo	$705,327	713077	($7,750)
14	Number of Months			12
15	Annaul Effect			($93,000)

Kentucky Power Company
Capacity Settlement Revenues
for the Month September 30, 2009

Exhibit EKW-13

Ln No (1)	Company (2)	Orginial MLR (3)	Revised MLR (4)	Member Primary Capacity (5)	Primary Capacity Reservation (6)	Surplus (Deficit) (7)	Capacity Rate (8)	Credit (Charge (9)
1	APCo	0.35084	0.35155	6,321,000	9,217,700	(2,896,700)	$11.9706	($34,675,372)
2	KPCo	0.07069	0.07084	1,453,000	1,857,400	(404,400)	$11.9706	($4,840,929)
3	I&M	0.17927	0.17963	5,155,000	4,709,900	445,100	$14.0600	$6,258,106
4	OPCo	0.21326	0.21166	8,450,000	5,549,700	2,900,300	$11.6500	$33,788,495
5	CSP	0.18594	0.18632	4,841,000	4,885,300	(44,300)	$11.9706	($530,300)
6	Total			26,220,000	26,220,000	0		$0

		Revised Charge	Original Charge	Difference
7	KPCo	($4,840,929)	($4,798,246)	($42,683)
8	Number of Months			12
9	Total			($512,196)

Kentucky Power Company
Capacity Settlement Revenues
for the Month September 30, 2009

Ln No (1)	Company (2)	Revised MLR (4)	Member Primary Capacity (5)	Primary Capacity Reservation (6)	Surplus (Deficit) Base (7)	Surplus (Deficit) exc CPL (8)	Capacity Rate Base (9)	Credit (Charge) Base (10)	Capacity Rate Exc CPL (11)	Credit (Charge) Exc CPL (12)
1	APCo	0.35155	6,321,000	9,217,700	(2,896,700)	(2,984,529)	$11.9706	($34,675,372)	$12.0980	($36,106,879.76)
2	KPCo	0.07084	1,453,000	1,857,400	(404,400)	(422,135)	$11.9706	($4,840,929)	$12.0980	($5,106,994.44)
3	I&M	0.17963	5,155,000	4,709,900	445,100	650,194	$14.0600	$6,258,106	$14.0600	$9,141,726.23
4	OPCo	0.21166	8,450,000	5,549,700	2,900,300	2,847,360	$11.6500	$33,788,495	$11.6500	$33,171,741.67
5	CSP	0.18632	4,841,000	4,885,300	(44,300)	(90,890)	$11.9706	($530,300)	$12.0980	($1,099,593.70)
6	Total		26,220,000	26,220,000	0	0		$0		$0.00

Ln No		Revised Charge	Base Charge	Difference
7	KPCo	($5,106,994)	($4,840,929)	($266,065)
8	Number of Months			12
9	Total			($3,192,780)

Exhibit EKW-14

Kentucky Power Company
Capacity Settlement Revenues/Expenses
for the months October 2008 - December 2008
using the September 30, 2009 Actual level of Investments

Ln No (1)	Company (2)	Revised MLR (3)	Member Primary Capacity (4)	Primary Capacity Reservation (5)	Surplus (Deficit) (6)	Actual Investment Rate (7)	Base Credit (Charge) (8)	Investment Rate w/ Sept Balances (9)	Revised Credit (Charge) (10)
1	APCo	0.35155	6,321,000	9,217,700	(2,896,700)	$8.1706	($23,667,664)	$9.6643	($27,994,682)
2	KPCo	0.07084	1,453,000	1,857,400	(404,400)	$8.1706	($3,304,175)	$9.6643	($3,908,258)
3	I&M	0.17963	5,155,000	4,709,900	445,100	$10.5200	$4,682,452	$10.6700	$4,749,217
4	OPCo	0.21166	8,450,000	5,549,700	2,900,300	$7.8100	$22,651,343	$9.5100	$27,581,853
5	CSP	0.18632	4,841,000	4,885,300	(44,300)	$8.1706	($361,956)	$9.6643	($428,130)
6	Total		26,220,000	26,220,000	0		($0)		$0
				Revised Charge	Base Charge	Difference			
7	KPCo			($3,908,258)	($3,304,175)	($604,083)			
8	Number of Months					3			
9	Total					($1,812,249)			
10	I&M Plant Balance @ Sept 2009			$3,977,592,028					
11	OPCo Plant Balance @ Sept 2009			$5,849,402,344					

Kentucky Power Company
Capacity Settlement Revenues
for the Month September 30, 2009
January 2009 - September 2009 Adjustment

Ln No (1)	Company (2)	Revised MLR (3)	Member Primary Capacity (4)	Primary Capacity Reservation (5)	Surplus (Deficit) (6)	Actual Investment Rate (7)	Base Credit (Charge) (8)	Investment Rate w/ Sept Balances (9)	Revised Credit (Charge) (10)
1	APCo	0.35155	6,321,000	9,217,700	(2,896,700)	$8.7107	($25,232,378)	$9.6643	($27,994,682)
2	KPCo	0.07084	1,453,000	1,857,400	(404,400)	$8.7107	($3,522,620)	$9.6643	($3,908,258)
3	I&M	0.17963	5,155,000	4,709,900	445,100	$10.5400	$4,691,354	$10.6700	$4,749,217
4	OPCo	0.21166	8,450,000	5,549,700	2,900,300	$8.4300	$24,449,529	$9.5100	$27,581,853
5	CSP	0.18632	4,841,000	4,885,300	(44,300)	$8.7107	($385,885)	$9.6643	($428,130)
6	Total		26,220,000	26,220,000	0		$0		$0

Ln No		Revised Charge	Base Charge	Difference
7	KPCo	($3,908,258)	($3,522,620)	($385,637)
8	Number of Months			9
9	Total			($3,470,733)
10	I&M Plant Balance @ Sept 2009	$ 3,977,592,028		
11	OPCo Plant Balance @ Sept 2009	$ 5,849,402,344		

Exhibit EKW - 16

KENTUCKY POWER CO.
SUMMARY OF DITC AMORTIZATION
Test Year September 30, 2009

SUMMARY	As of December 31 2008 Deferral Balance	Feedback Balance	Net DFIT Balance	2009 Amortization	Net DITC @ 12-31-2009	2010 Amortization	Net DITC @ 12-31-2010	2011 Amortization	Net DITC @ 12-31-2011
ACCOUNT 255 BALANCE --- DEBIT (CREDIT)									
012A - SEC Allocation - ITC - 10%	(14,667,242)	13,425,244	(1,241,998)	376,930	(865,068)	282,946	(582,122)	231,919	(350,203)
012C - Tax Reallocation - ITC - 10%	(8,601,431)	8,028,002	(573,429)	286,714	(286,715)	286,715	0	0	0
012G - SEC Allocation - ITC - 4%	(4,148,724)	4,148,724	0	0	0	0	0	0	0
012S - SEC Allocation - ITC - HRJ - 10%	(6,259,562)	5,555,775	(703,787)	158,342	(545,445)	134,429	(411,016)	127,456	(283,560)
012T - SEC Allocation - ITC - HRJ - 4%	(10,890)	10,890	0	0	0	0	0	0	0
Total - All Jurisdictions	(33,687,849)	31,168,635	(2,519,214)	821,986	(1,697,228)	704,090	(993,138)	359,375	(633,763)

		Debit (Credit) Acct 4114001	
DITC Amortization During Rate Year:			
Assumes that Rates go into effect July 1, 2010:			
Amortization --- July 1, 2010 thru December 31, 2010		(352,045)	
Amortization --- January 1, 2011 thru June 30, 2011		(179,688)	
DITC Amortization for 12 months after Rates go into effect		(531,733)	
DITC Amortization during Test Period		(826,424)	
DITC Amortization Adjustment --- Total Company		294,691	Debit to Account 4114001
DITC Amortization Adjustment --- Kentucky Jurisdiction	99.1000%	292,039	Debit to Account 4114001

Exhibit EKW-17

Kentucky Power Company
Capacity Settlement Revenues
for the Month September 30, 2009
Addition of 100MW of Wind Capacity @ KPCo

Ln No (1)	Company (2)	Revised MLR (4)	Surplus (Deficit) Base (7)	Surplus (Deficit) w/ Wind (8)	Capacity Rate Base (9)	Credit (Charge) Base (10)	Capacity Rate w/ Wind (11)	Credit (Charge) w/ Wind (12)
1	APCo	0.35155	(2,984,529)	(2,998,344)	$12.0980	($36,106,880)	$12.0951	($36,265,308)
2	KPCo	0.07084	(422,135)	(385,619)	$12.0980	($5,106,994)	$12.0951	($4,664,102)
3	I&M	0.17963	650,194	643,134	$14.0600	$9,141,726	$14.0600	$9,042,470
4	OPCo	0.21166	2,847,360	2,839,042	$11.6500	$33,171,742	$11.6500	$33,074,834
5	CSP	0.18632	(90,890)	(98,213)	$12.0980	($1,099,594)	$12.0951	($1,187,894)
6	Total		0	0		$0		$0

Ln No		Revised Charge	Base Charge	Difference
7	KPCo	($4,664,102)	($5,106,994)	$442,892
8	Number of Months			12
9	Total			$5,314,706

Assumes 100 MW wind purchase at 39.3% Capacity Factor

Exhibit EKW-18

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY — CASE NO. 2009-00459

DIRECT TESTIMONY
OF
SCOTT C. WEAVER

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY
OF
SCOTT C. WEAVER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

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EXHIBIT SCW-1A: Kentucky Power Company-Projected Winter Peak Demands, Generating Capabilities and Margins (2008/2009-2022/2023)

EXHBIIT SCW-1B: Kentucky Power Company-Projected Summer Peak Demands, Generating Capabilities and Margins (2009-2023)

EXHIBIT SCW-2: AEP-System; AEP-Eastern Zone; Kentucky Power Company - CUMULATIVE Renewable Resources Required to Approach and Approximate 7% System Target by 2013 and 10% by 2020

EXHIBIT SCW-3: Kentucky Power Company-Relative Change in Annual Revenue Requirement / Project Cost Comparison Due to Proposed 100 MW LDWEC PPA

DIRECT TESTIMONY OF SCOTT C. WEAVER ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power Company ("Kentucky Power, KPCo or Company").

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Business Administration Degree in Accounting from Ohio University in 1981, and a Master of Business Administration from the same university in 1985. In addition, in 1996 I completed both the American Electric Power System Management Development Program at The Ohio State University as well as The Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controllers Department (now Corporate Planning and Budgeting Department), and was subsequently named Assistant Financial Analyst in 1983, Financial Analyst in 1986, Senior Financial Analyst in 1987, and Senior Administrative Assistant II in 1990. In 1991, I transferred to the AEPSC Fuel Supply Department as Manager-Administration. I was subsequently named Manager-Administration and Purchasing in 1994 and Director of Power Generation Business Planning and Financial Management in 1996. I transferred to the AEP Wholesale business unit in 2000 as Manager-Business Planning and in January 2003 I transferred back to the Corporate Planning and Budgeting Department as Director of Operational Analysis. I assumed my present position in May 2003.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR–RESOURCE PLANNING AND OPERATIONAL ANALYSIS?**

A. I am responsible for the supervision and administration of long-term generation resource planning and supply-side operational analysis for AEP. In such capacity, I coordinate the use of short- and long-term generation production costing as well as other resource planning models, used in the ultimate development of operating and capital budget forecasts for Kentucky Power Company and its parent, AEP. I also regularly monitor actual performance and review the preparation of forecasted information for use in regulatory proceedings.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?**

A. Yes. Over the last four years I will have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight state commissions, including Arkansas, Indiana, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

III. PURPOSE OF TESTIMONY

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

A. The purpose of this testimony is to:

1. Offer a brief overview of the KPCo and AEP resource planning process;
2. describe KPCo and AEP's inclusion of renewable resources in the overall Integrated Resource Planning (IRP) process, particularly given the prospects for federal legislation around greenhouse gases (GHG) and renewable energy requirements and the termination of the current federal production tax credits currently available to support renewable project development; and
3. offer an economic analysis that would support the approval of the Company's proposed Wind Power Purchase Agreement (PPA) between KPCo and FPL Energy Illinois Wind, LLC (FPLEWIC) also known as the Lee-DeKalb Wind Energy Center (LDWEC) for the sale of a 100 MW share of its electrical output and environmental attributes to KPCo for a 20 year period and which is anticipated to be in-service in 2010.

Specifically, this analysis will reflect wind energy contributions established within the context of the 2009 Kentucky Power Company IRP Report which was recently filed with this Commission in Case No. 2009-00339, on August 17, 2009.

Q. WERE THE SCHEDULES USED TO SUPPORT YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

IV. RESOURCE PLANNING OVERVIEW

Q. CAN YOU PROVIDE A BRIEF OVERVIEW OF THE INTERRELATIONSHIP BETWEEN KPCO AND AEP FOR PURPOSE OF DETERMINING CAPACITY RESOURCE REQUIREMENTS?

A. Yes. The AEP System includes eleven utility operating companies, operating in eleven states, with generation and transmission assets primarily in two different Regional Transmission Organization (RTO) planning and operational regions. Those RTOs are the PJM Interconnection, L.L.C. (PJM), in which AEP's Eastern Zone is located, and the Southwest Power Pool (SPP) in which AEP's Western Zone is located. KPCo is a wholly-owned subsidiary of AEP—serving retail customers in eastern Kentucky—and is located in AEP's Eastern Zone. In addition to KPCo, the AEP Operating Companies in the Eastern Zone (collectively, AEP-East) are:

- Appalachian Power Company (APCo), serving portions of West Virginia and Virginia;
- Columbus Southern Power Company (CSP), serving portions of central and southern Ohio;
- Indiana Michigan Power Company (I&M), serving portions of northern Indiana and southwestern Michigan; and
- Ohio Power Company (OPCo), serving portions of Ohio.

Additionally, two other Operating Companies residing in the AEP Eastern Zone, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo), represent non-generating affiliates.

AEP-East collectively serves about 3.6 million customers in an approximate 90,000 square-mile area of Virginia, West Virginia, Ohio, Indiana, Michigan, Kentucky and Tennessee.

Q. WOULD YOU PLEASE PROVIDE A BRIEF DESCRIPTION OF KPCO'S CUSTOMER BASE?

A. KPCo's customers consist of both retail and sales-for-resale customers located in eastern Kentucky. The majority of these customers, comprising nearly 99 percent of KPCo's internal energy sales in 2008, consisted of over 175,000 residential, commercial, and industrial retail end-use customers. The remaining 1 percent of KPCo's energy sales in 2008 came from municipal utilities to which KPCo provides wholesale service for ultimate distribution and resale to their end-use customers.

Q. WOULD YOU PLEASE PROVIDE A DESCRIPTION OF HOW KPCO SERVES THE DEMAND AND ENERGY REQUIREMENTS OF THIS CUSTOMER BASE?

A. The peak load requirement of KPCo's customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, KPCo's highest recorded summer peak was 1,358 MW, which occurred in July 2005; and the highest recorded winter peak was 1,685 MW, which occurred in January 2005. KPCo's most recent winter and summer peaks were 1,674 MW and 1,163 MW occurring in January and August of this year, respectively. KPCo's 2008 energy sales to retail and internal wholesale customers were 7,342 GWh.

To meet the peak demand and annual energy requirements of its customers, at year-end 2008 KPCo relied on 1,453 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability (winter ratings), with all of that generating capability representing coal-fueled baseload capacity.[1] In addition to its owned (and entitlement) capacity, in order to meet the needs of its customers that are in excess of what is supplied from its owned resources, KPCo has historically relied on capacity and energy purchases from the generating resources of the other AEP-East operating companies pursuant to the 1951 AEP Interconnection Agreement (the AEP Pool).

Q. HOW WILL THE FUTURE DEMAND AND ENERGY REQUIREMENTS OF KPCO'S CUSTOMERS BE SERVED?

A. The future capacity and energy resource needs of KPCo are established in concert with that of the other AEP-East Operating Companies under the auspices of the AEP Pool, which was established for the purpose of obtaining the most efficient coordinated expansion and operation of AEP's power supply facilities. Through an integrated and coordinated approach to resource planning, each of the Member Companies within the AEP Pool, including KPCo, is provided with the benefits of economies not achievable on a stand-alone basis.

As part of the resource planning process, the AEP System considers various supply-side options including simple cycle combustion turbine units, natural gas combined cycle units, supercritical pulverized coal units, integrated gasification combined cycle units, nuclear units, distributed generation, energy storage technologies, as well as purchases from the wholesale market. In addition, the AEP System is also pursuing reasonably priced "renewable" technologies, such as wind energy and biomass.

[1] Big Sandy Unit 1 (260 MW); Big Sandy Unit 2 (800 MW); Rockport Unit 1 (Purchase entitlement from AEP Generating Co., 198 MW); Rockport Unit 2 (Purchase entitlement from AEP Generating Co., 195 MW)

V. KPCO AND AEP FUTURE VIEW OF RENEWABLE RESOURCES WITHIN ITS IRP

Q. FIRST, WOULD YOU PLEASE PROVIDE A DESCRIPTION, IN THE CONTEXT OF KPCO'S LATEST (2009) IRP, OF HOW KPCO PLANS TO SERVE THE DEMAND AND ENERGY REQUIREMENTS OF ITS CUSTOMER BASE?

A. As noted earlier, the future capacity and energy resource needs of KPCo are established in concert with that of the other AEP-East Operating Companies under the auspices of the AEP Pool.

Exhibit SCW-1A and SCW-1B offer a "Capacity, Load, Reserve" (CLR) table for KPCo—submitted as part of the formal KPCo and AEP-Eastern Zone 15-year 2009 IRP planning period ending 2023—for the winter and summer peaking periods, respectively. As the schedules indicate, KPCo's CLR includes various demand-side and supply-side options. The supply-side approach includes the need for intermediate/load-following capacity (proxied as a natural gas combined cycle [CC] unit); peaking capacity (proxied as natural gas simple-cycle combustion turbine [CT] units); and the addition of renewable resources in the form of wind capacity and energy.

Q. WOULD YOU PLEASE PROVIDE A DESCRIPTION OF THE RENEWABLE RESOURCES INCLUDED IN THIS KPCO IRP-BASED CLR TABLE?

A. In early 2007, as part of AEP's comprehensive strategy to address GHG emissions, the AEP System (both its Eastern and Western Zones) committed to the acquisition of energy from 1,000 MW (nameplate) of additional wind generation projects by the end of 2010 via long-term purchase power agreements. This was part of an overall AEP strategy at the time to incorporate a renewable energy portfolio target equal to five percent (5%) of energy sales by the year 2020.

However, considering the increasing number of state renewable energy mandates and, more specifically, the growing prospect of comprehensive federal legislation around GHG that would likely be inclusive of renewable energy requirements, AEP has now doubled this internal target by committing to incrementally add a total of 2,000 MW of renewable energy across its eleven-state system by the end of 2011. Such updated goals have been formally published as part of its *2009 Corporate Sustainability Report.* [2] Likewise, for reasons I will further discuss, AEP's overall longer-term renewable energy portfolio target has also been doubled, increasing to ten percent (10%) of retail energy sales by the year 2020. To be successfully implemented, however, AEP's internal renewable targets will require support from regulators.

Efforts to meet these renewable goals and internal targets are underway. A total of 277 MW (nameplate) of wind projects have been recently transacted in the AEP System-Western Zone. The AEP System-Eastern Zone is already receiving energy from the Camp Grove and Fowler Ridge wind projects with a total nameplate rating of 275 MW. Additional contracts have been recently executed in AEP-East for each of the other Member Companies (APCo, CSP, I&M, and OPCo) for another 351 MW to be placed in service in 2009 and 2010. As discussed further by Company Witness Jay Godfrey, on behalf of all of its affiliate regulated operating companies, including KPCo, AEP solicited in June of 2009 a System-wide Request for Proposal (RFP) for up to 1,100 MW

[2] Available at http://www.aep.com/citizenship/crreport/docs/CS_Report_2009_web.pdf

(nameplate) of additional renewable resources by the end of 2011 that would be required to achieve this goal.[3] [4]

Q. WHAT LEVEL OF RENEWABLE ENERGY WOULD THIS INCREMENTAL 2,000 MW OF RENEWABLE RESOURCES BRING TO THE AEP SYSTEM?

A. That will not be known until the specific type of future renewable generation projects are ultimately identified and selected. However, assuming nearly all of it would be in the form of wind energy, this incremental 2,000 MW would offer approximately 6,100 GWh of renewable energy. As a percent of projected AEP System-wide retail sales in 2011 that may be approaching roughly 150,000 GWh, this incremental energy would increase AEP's renewable energy position by an additional 4.1 percent by the end of 2011.[5]

Q. IN ADDITION TO WIND, WHAT OTHER RENEWABLE TECHNOLOGIES ARE KPCO AND AEP CONSIDERING?

A. Other renewable technologies were screened for cost-effectiveness, including biomass co-firing, in which a small amount (up to about 2% of the combined fuels' heat content) of biomass feedstock is fired in boilers along with coal; and biomass separate injection, in which larger amounts of biomass (up to 10% of the combined fuels' heat content) are injected separately into boilers. Though very preliminary, the current indicative planning includes the potential for biomass co-firing at Rockport Units 1 or 2 by 2013, as well as biomass separate injection at KPCo's Big Sandy Unit 2 by 2015.

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[3] (2,000 MW Goal – 277 MW – 275 MW – 351 MW = ~1,100 MW)

[4] Such renewable resources to be considered including wind, commercial-scale solar, biomass, geothermal, biologically-derived methane gas, and hydroelectric (as certified by the Low Impact Hydro Institute).

[5] (2,000 MW x 8,760 hr/yr x 35% [assumed] capacity factor / 1,000 = ~6,100 GWh / 150,000 GWh = ~4.1%)

Based on current cost and performance parameters, other renewable technologies such as solar energy remain relatively expensive, particularly in the geographic region of the country occupied by the AEP-Eastern Zone. The renewable plan for AEP-East does include limited solar energy by the end of 2009, but this is being driven by mandated requirements for solar that have been established specifically in the state of Ohio. KPCo's resource plan at this time does not include solar energy within the nearer-term plan period.

Q. **WHY ARE RENEWABLE TECHNOLOGIES BEING CONSIDERED AS PART OF THE KPCO AND AEP RESOURCE PLANNING PROCESS?**

A. As part of the planning process, the AEP System has incorporated a comprehensive strategy to reduce, avoid, or offset future GHG emissions, chief among those gases, carbon dioxide (CO_2). Achieving this strategy has involved a commitment to a diverse portfolio of solutions including:

- demand side/energy efficiency programs;
- efficiency improvements to existing fossil-fueled plants;
- the potential diversification of its fuel mix to consider larger contributions from lower CO_2-emitting natural gas generation resources;
- possible construction of advanced technology baseload coal-fueled plants that would offer improved thermal efficiency and, with that, lower emissions;
- carbon capture and sequestration technology;
- reforestation, methane capture and other carbon offset project alternatives; and
- the ownership and operation, and/or long-term purchase of renewable energy resources, including wind.

This strategy is intended to yield the environmental benefit of reduced GHG emissions, and serve to mitigate the potential for significant rate increases to customers attributable to any future Global Climate Change/GHG reduction legislation—likely to be inclusive of renewable energy standards—or regulated emission reduction mandates.

Q. WHY IS AEP ACCELERATING ITS ACQUISITION OF RENEWABLE RESOURCES?

A. The decision to accelerate the acquisition of renewable resources reflects a number of factors and trends. Many of the other states in which AEP operates have adopted mandatory RPS requirements, including three in the AEP-Eastern Zone (Ohio, Michigan and West-Virginia)[6], while Virginia has a voluntary goal. AEP also recognizes that mandatory RPS requirements are likely to be ultimately required at the federal level. The U.S. House of Representatives' recently-passed the Waxman-Markey Climate Change Bill (H.R. 2454) included a combined federal renewable energy standard (RES) and energy efficiency standard (EES) beginning in 2012, plateauing at a 20 percent contribution level[7] by 2020—with a minimum renewable energy contribution component at that point of 15 percent. Moreover, the U.S. Senate also recently passed out of its Energy and Natural Resources (E&NR) Committee a combined RES/EES (S. 1462) beginning in 2011, plateauing at 15 percent by 2021—that would then require a minimum renewable energy component of 11 percent.

It is interesting to note that the largely 'stand-alone' RES/EES that was passed out of the Senate E&NR Committee earlier this year enjoyed bi-partisan support. The bill was

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[6] AEP-Eastern Zone states with renewable energy requirements include: Ohio (Substitute S.B. 221), Michigan ("Clean, Renewable and Efficiency Energy Act"-2008 PA 295), and West Virginia ("Alternative and Renewable Energy Portfolio Act"-Enrolled H.B. 103). Indiana has pending H.B. No. 1305 which would establish a 25% target renewable percentage by 2027, while Kentucky has no pending legislation.

[7] As a percent of retail load serving entity sales.

voted out of committee with 15 ayes, and 8 nays (with Republican Committee members voting 4 aye, 6 nay). This is in contrast to the comprehensive Climate Change Bill (Waxman-Markey) that passed out of the full U.S. House by a vote of 219-to-212 (with only 8 Republicans voting in favor). This could suggest that establishing, minimally, renewable energy standards at the federal level could be far less contentious among policy makers going-forward.

Given the increasing probability of federal renewable energy legislation—either as part of comprehensive federal Climate Change/GHG legislation, or as a unique "carve-out"—KPCo and AEP have determined it is reasonable to begin to add to their renewable energy portfolios now as part of their resource planning process. (Company Witness Godfrey discusses in greater detail the benefits of locking in long-term prices of renewable generation). Thus, as part of the 2009 IRP process, it was assumed that AEP would target to achieve at least a seven percent (7%) system-wide renewable energy portfolio by the year 2013 (i.e. available by the end of 2012), increasing to the previously-mentioned ten percent (10%) target by the year 2020, a level that conservatively approaches—but still falls below—the quantities currently being considered by Congress.

Q. KENTUCKY CURRENTLY HAS NO RENEWABLE PORTFOLIO STANDARD. PLEASE COMMENT ON ANY EFFORTS YOU ARE AWARE OF IN THE STATE THAT WOULD POINT TO THE INITIATION OF SUCH A STANDARD.

A. As discussed more completely by Company Witness Mosher, in November 2008 Governor Beshear unveiled a comprehensive energy plan [8] that would address future energy-related challenges for the state, including the development of diverse and clean energy resources. At the top of a list of seven key "strategies", this initiative set forth a proposed Renewable and Energy Efficiency Portfolio Standard, whereby twenty-five percent of Kentucky's energy needs in 2025 will be met by reductions through energy efficiency and conservation and through the use of renewable resources. Of that total amount, seven percent would be met through the use of renewable resources such as solar, wind, hydro, and biofuels.

Q. HAS THE PROSPECT OF THE FUTURE TERMINATION OF FEDERAL PRODUCTION TAX CREDITS, CURRENTLY AVAILABLE TO WIND AND OTHER RENEWABLE RESOURCE PROJECT DEVELOPERS, AFFECTED AEP AND KPCO'S PLANNING?

A. Yes. AEP and KPCo's decision to pursue an expanded and accelerated renewable portfolio is certainly influenced by the expiration on December 31, 2012 of the federal Production Tax Credits (PTCs) that are currently available for wind developers. PTCs for wind energy offer tax credit benefits to project developers equal to 2.1 cents per kilowatt-hour of renewable energy generated over the ten-year credit eligibility period. This would equate to a pre-tax (revenue requirement) benefit of approximately 3 cents/kWh, or $30/MWh. Therefore, without the PTCs, significant incremental costs would be passed through by wind project developers to its wholesale purchasers, and could result in a significant prospective increase in the cost of purchased (or self-developed and owned) wind energy.

[8] Plan entitled, "Intelligent Energy Choices for Kentucky's Future".

Q. ON SEVERAL PREVIOUS OCCASSIONS CONGRESS HAS "EXTENDED" SUCH FEDERAL PRODUCTION TAX CREDITS. WHAT IS THE PROSPECT THAT FURTHER EXTENSIONS—BEYOND DECEMBER 31, 2012 FOR WIND PROJECT DEVELOPMENT—WILL BE AUTHORIZED BY CONGRESS?

A. The prospect of such subsidization extensions would be less likely assuming some form of federal renewable energy standard is ultimately established. It's analogous to a classic "carrot" and "stick" behavioral influence. PTCs represent the "carrot"; an inducement offered to the marketplace to site, develop and build renewable resources. A federal legislated mandate around achievement of specific renewable energy thresholds—the "stick"—would require action to be taken whether financial incentives were available or not. To have both would be unnecessary.

Q. ASSUMING THESE AEP SYSTEM RENEWABLE ENERGY TARGETS BY THE YEAR 2013 AND, ULTIMATELY, BY 2020, WERE LIKEWISE APPLIED TO EACH OF ITS OPERATING COMPANIES, WHAT LEVELS OF WIND CAPACITY WOULD BE REQUIRED BY KPCO?

A. Assuming: 1) wind represented the exclusive source of renewable resources, 2) KPCo's forecasted retail energy sales of 7,602 GWh in 2013 and 7,956 GWh in 2020, and 3) that the presumed capacity factor from such wind resources were estimated to be in the mid-thirty percent range (say, 35%), then the following Table 1 offers the required wind capacity to achieve such targeted renewable levels:

Table 1
KPCo
Equivalent Wind Capacity Necessary to Achieve Renewable Energy Targets
Based on 2009 IRP

Year	(1) AEP Approximate Renewable Energy Target	(2) Forecasted KPCo Retail Sales (Gwh)	(1) x (2) Required Renewable Energy (Gwh)	Assumed Wind Cap. Factor	Required Wind Capacity * (MW)
2013	7%	7,602	532	35%	**174**
2020	10%	7,956	796	35%	**259**

* Represents nameplate capacity calculated as follows: Required Energy / C.F. / 8760 hrs. * 1000

As reflected in Table 1, the equivalent "targeted" level of wind resources required by KPCo in the year 2013 of 174 MW, would significantly exceed the levels of wind energy currently under consideration (100 MW, nameplate) as part of the proposed LDWEC purchase agreement. In fact, such 100 MW KPCo wind portfolio amount would represent only 39 percent of the equivalent ultimate 259 MW (10 percent) level established for the year 2020.

Q. AS PART OF THE COMPANY'S 2009 IRP, KPCO EXHIBIT SCW-1A INDICATES TWO SEPARATE 50 MW WIND RESOURCE TRANCHES FOR KPCO IN THE (WINTER PLANNING) YEARS 2010 AND 2011, RESPECTIVELY. WHY IS KPCO NOW SEEKING APPROVAL OF A SINGLE 100 MW WIND RESOURCE TRANSACTION THAT WOULD BE EFFECTIVE IN 2010?

A. The renewable resource plan for KPCo as reflected in its 2009 IRP and identified in Exhibit SCW-1A (and 1B), represents a generic renewable planning profile that was reasonably established at that time to include a total of 100 MW (nameplate) of wind resources, albeit in two unique 50 MW tranches. In general, however, KPCo's decision to now contract for the (full) 100 MW by way of this single LDWEC project does not represent a departure from the original plan, other than a slight acceleration in its implementation. As discussed more fully by Company Witness Godfrey, to achieve the broader renewable energy objectives of KPCo and its affiliate regulated operating companies, on June 1, 2009, AEP, issued an RFP for 1,100 MW of renewable power and energy, with proposed commercial operating dates beginning December 31, 2009, but no later than December 31, 2011. This LDWEC project simply represents a partial implementation of that objective.

Q. **BY THE YEAR 2013 (END OF 2012), WHAT LEVEL OF NAMEPLATE WIND CAPACITY IS REFLECTED IN THE 2009 RESOURCE PLANNING THAT WOULD CONTRIBUTE TO THE ACHIEVEMENT OF A SEVEN PERCENT (7 PERCENT) "INTERIM" AEP SYSTEM RENEWABLE TARGET?**

A. Table 2 offers a summary of the potential renewable/wind profile by the end of 2012 for KPCo and the AEP System as a whole:

Table 2

KPCo and AEP System
Wind Profile (through 2012)
Based on 2009 IRP
--MW Nameplate Capacity--
(As of November, 2009)

	Project Name	Per Plan	Proposed PPAs	Executed PPAs	In-Service
KPCo					
In-Service By 12/31/XX:					
2010	*Lee-DeKalb Wind Energy Center* (A)	50	50	-	*2010*
2011		50	50	-	*2010*
2012	-	-	-	-	
KPCo TOTAL		*100* (B)	*100*	-	
AEP System					
"Legacy" Wind	(Various-PSO and SWEPCO)	424		n/a	424
In-Service By 12/31/XX:					
2008	Camp Grove (APCo)	75		75	75
2009	Fowler Ridge (AP/I&M)	200		200	200
	Grand Ridge II & III (APCo)	100.5		100.5	*(est. 12/09)*
	Fowler Ridge II (CSP/I&M/OP)	150		150	*(est. 12/09)*
	Majestic (SWEPCO)	79.5		79.5	79.5
2010	Beech Ridge (APCo)	100.5		100.5	*(est. 6/10)*
	Blue Canyon V (PSO)	99		99	*(est. 3/10)*
	Elk City (PSO)	98.9		98.9	*(est. 3/10)*
	Lee-DeKalb Wind Energy Center (KPCo)	100	100	-	*2010*
Subtotal (Identified Incremental Projects)		*1,003.4*	*100*	*903.4*	
2010	*Unidentified*	*600* (D)	-	-	-
2011	*Unidentified*	*800*	-	-	-
2012	*Unidentified*	*650*	-	-	-
		(B) 1,100 (C)			
AEP System TOTAL (Including "Legacy" Wind)		*3,477*	*100*	*903*	*778*
Established Short-Term (thru 2011) AEP Renewable GOAL		2,000			

(A) Assumes all nearer-term KPCo wind energy requirements --as set forth in its 2009 IRP as two (2) 50-MW tranches in 2010 and 2011, respectively-- would be achieved through this proposed 100-MW PPA/take from the LDWEC project.

(B) See KPCo Exhibit SCW-2

(C) On June 1, 2009, AEPSC, on behalf of all of its regulated operating company affiliates, issued a Request for Proposal for 1,100 MW of renewable energy resources (amount required to achieve 2,000 MW 'target') to be in-service no later than December 31, 2011.

(D) Additional solicitations *above* the recent 1,100 MW bid, necessary to achieve 'Per Plan' levels thru 2011 may be considered based on results of the June '09 solicitation.

This Table 2 summary would indicate that as part of the 2,000 MW AEP System renewable resource goal by the end of 2011, the current plan for KPCo reflects the potential for as much as 100 MW (nameplate) of additional wind resources by year-end 2011 (50 MW in 2010, and 50 MW in 2011). Again, this total amount of wind resources is now represented by the proposed 100 MW acquisition from the LDWEC project. Recall, as identified on Table 1, this 100 MW cumulative total for KPCo, however, would still fall below the 174 MW of (equivalent) wind capacity that would be required by KPCo to equally contribute—along with its affiliate AEP operating companies—in the achievement of an approximate seven percent (7%) AEP System target by 2013.

Q. KPCO'S OVERALL RENEWABLE PLAN WOULD ADD RENEWABLE RESOURCES TO AN ELECTRIC UTILITY OPERATING IN A STATE—KENTUCKY—WHICH CURRENTLY HAS NO RENEWABLE PORTFOLIO STANDARD. WHY THEN IS THE ATTAINMENT OF SUCH RENEWABLE RESOURCE AMOUNTS NECESSARY, AND HOW CAN THAT BE CONSIDERED TO BE IN THE BEST INTERESTS OF THE CUSTOMERS OF KPCO?

A. First and foremost, as will be discussed later in this testimony, the relative cost of electricity inclusive of the LDWEC wind generation under consideration, is competitive with alternative resources available to KPCo. Second, with the current federal PTCs for wind development now set to expire at the end of 2012, it would be anticipated that the costs of wind projects placed into service after that expiration date will significantly increase. As more fully discussed in the testimony of Company Witness Godfrey, by acting now to secure wind contracts, KPCo is locking in wind energy at a relatively low cost.

Third, under the very reasonable prospect that a federal renewable energy standard *will* become law—whether included as a component of more comprehensive GHG legislation, or carved-out under separate legislation—demand for renewable resources including wind energy will undoubtedly increase, further driving up the costs to KPCo's customers over the long-term.

Therefore, the development of a KPCo plan to add sufficient renewable resources prior to the expiration of the PTCs could serve to mitigate KPCo's customers' exposure to the cost risks associated with such potential federal renewable energy and/or GHG legislation.

Q. FINALLY, GIVEN THAT THE RESOURCE PLANNING FOR AEP'S EASTERN ZONE IS ESTABLISHED ON BEHALF OF ALL OF THE AEP COMPANIES OPERATING IN THAT REGION, HOW DOES KPCO'S FUTURE RENEWABLE PORTFOLIO DISCUSSED IN THIS SECTION OF YOUR TESTIMONY COMPARE TO THE OVERALL AEP-EAST PLAN AS A WHOLE?

A. Exhibit SCW-2 offers a summary view of the KPCo renewable profile including the other AEP-East operating companies, as well as the AEP-West (SPP) operating companies that have been incorporated into the 2009 IRPs for the AEP-Eastern and AEP-Western Zones, respectively. In addition to identifying the respective (nameplate) MW amounts, by company, by year, by renewable alternative, the Exhibit also offers the relative percent of each operating companies' retail energy sales that would be met by renewable generation resources.

Specifically, this Exhibit SCW-2 suggests that KPCo and its affiliate AEP-East operating companies are anticipated to generally converge with reasonably consistent total renewable generation mixes in both the targeted 2013 and 2020 timeframes discussed earlier in this testimony. Any deviation may be attributed to unique timing of any state-specific requirements, or the recognition that certain options, such as biomass and solar, may not be generally available or economically viable until later in the planning horizon.

VI. ECONOMIC REVIEW OF THE LEE-DEKALB WIND ENERGY CENTER PROJECT

Q. HAVE YOU PREPARED ANY ANALYSIS OF THE PPA TRANSACTIONS FOR THE LDWEC PROJECT?

A. Yes. Exhibit SCW-3 identifies the estimated KPCo-specific annual revenue requirement impacts associated with the proposed 100 MW PPA from the LDWEC project. Exhibit SCW-3 represents a year-specific summarization of the estimated impacts of this transaction would have on KPCo's production-related pre-tax costs of service (i.e. revenue requirement). Exhibit SCW-3, has a public version and a version for which the Company is seeking confidential treatment pursuant to KRS 61.878 and 804 KAR 5:001, Section 8.

Q. HOW WAS THIS ANALYSIS PERFORMED?

A. Separate dispatch emulations were performed in our Promod model comparing AEP-East Member Company—including KPCo—production cost profiles that both included *and* excluded the assignment of this 100 MW of wind energy to KPCo. Based on a comparison of those two emulations, then all KPCo variable *energy* costs directly associated with the PPA contract as well as all avoided internal generation and/or "(AEP) Pool-related" variable/energy costs could be uniquely identified. In addition to establishing a relative variable cost comparison, recognizing the attendant *capacity* value of the wind resource, the incremental reductive impact on KPCo's AEP Pool capacity settlement charges was also determined.[9]

Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?

A. In summary, Exhibit SCW-3 (col. J) indicates that the LDWEC PPA would have an order of magnitude impact of 0.07 (seven one-hundredths) of a cent per kWh effect on KPCo's production-related costs over the ten-year average period (2010-2020). Stated another way, a typical residential customer utilizing 1,000 kWh per month would pay approximately 70 cents more on his/her monthly electric bill in exchange for this diverse, carbon-free energy resource.

Q. WHAT ADDITIONAL ANALYSIS WAS PERFORMED?

A. Exhibit SCW-3 (col. L) also offered these respective net costs associated with the LDWEC project, as a function of the estimated *wind energy to be received* from the KPCo's proposed 100 MW share of the facility (col. C). That result suggests the "net" costs of the project are generally in the $15-to-$18 per Mwh range.

VII. CONCLUSIONS

Q. DO THESE ANALYSES DEMONSTRATE THE REASONABLENESS OF THE COSTS OF THE LDWEC PROJECT PPA?

A. Yes. As reflected in Exhibit SCW-3, the cost from the wind generation to be received from the LDWEC project PPA would be very competitive versus alternative resources for KPCo, as it would represent a very small relative impact on going-forward costs of service.

[9] For purpose of this calculation, intermittent resources such as wind are recognized in the AEP capacity settlement as offering a "Primary Capacity" contribution to the owning/purchasing Member Company equal to the estimated capacity factor of the resource. In other words, the 100 MW (nameplate) LDWEC would increase KPCo's Primary

This is due in part to the implicit benefit of a lower PPA cost received via developer utilization and pass-through of available federal subsidies—discussed earlier in this testimony—such as the federal PTCs, as well as the ability to offset rising fossil fuel costs, and energy and capacity charges avoided by KPCo through the AEP Pool.

Moreover, when comparing the (net) cost of the LDWEC project to the alternative that may be available to KPCo in lieu of having such renewable energy—i.e., the prospect of acquiring qualifying Renewable Energy Certificates (RECs)—then the ultimate benefits to KPCo's customers is brought into clearer focus. Based on this analysis, the (net) cost of this wind project (Exhibit SCW-3, col. L) when compared to Company estimates of such RECs (col. M) would suggest that these incremental or "net" costs of the LDWEC project are indeed anticipated to be lower than, alternatively, acquiring RECs alone. Plus, possessing the renewable energy offered by the project offers KPCo with the further, non-quantified societal benefit of a more environmentally-friendly generation portfolio.

A final conclusion can also be drawn from the table of data extended at the bottom of Exhibit SCW-3 (cols L and M). That is, if KPCo were to defer a decision around the LDWEC Project by waiting until such time that available federal PTCs for wind development would be anticipated to expire, the advantages offered by such earlier action would likewise be eliminated.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Capacity in the AEP-Pool by approximately 100 MW x 39.3%, or ~39 MW. The 39.3% figure representing the estimated annual capacity factor associated with this LWDEC project.

AFFIDAVIT

Scott C. Weaver, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Scott C. Weaver

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Scott C. Weaver this 31st day of December 2009.

Notary Public

NOTARY PUBLIC STATE OF OHIO

Sharon Hutchens
Notary Public-State of Ohio
My Commission Expires
November 17, 2014

My Commission Expires 11/17/2014

Kentucky Power Company
Projected Winter Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2008/2009 - 2022/2023)
Per 2009 KPCO (and AEP-Eastern Zone) IRP

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
					=Sum(1-4)		=Sum(5-6)						=((8)-(9))+Sum(11)+(12)	=(13)-(5)	=(14)/(5)*100	=(13)-(7)	=(16)/(7)*100
	Peak Demand - MW							Capacity - MW						Reserve Margin - MW			
Winter Season	Internal Demand (a)	Internal Wholesale Contracts	DSM (b)	Committed Sales (c)	Net Demand	Interruptible Demand	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Planned Capacity Additions: Units	Planned Capacity Additions: MW (f)	Annual Purchases	Total Capacity	Reserve Margin Before Interruptible	% of Internal Demand	Reserve Margin After Interruptible	% of Internal Demand
2008/09	1,615	0	(1)	15	1,629	0	1,629	1,453	117				1,336	(293)	(18.00)	(293)	(18.00)
2009/10	1,640	0	(8)	15	1,647	0	1,647	1,453	72				1,381	(266)	(16.20)	(266)	(16.20)
2010/11	1,670	0	(16)	0	1,654	0	1,654	1,453	72	50 MW Wind	6	0	1,387	(267)	(16.10)	(267)	(16.10)
2011/12	1,674	0	(18)	0	1,656	0	1,656	1,453	66	50 MW Wind	6	0	1,400	(256)	(15.50)	(256)	(15.50)
2012/13	1,691	0	(20)	0	1,671	0	1,671	1,453	(8)				1,474	(197)	(11.80)	(197)	(11.80)
2013/14	1,702	0	(22)	0	1,680	0	1,680	1,453	(9)				1,475	(205)	(12.20)	(205)	(12.20)
2014/15	1,713	0	(24)	0	1,689	0	1,689	1,428	(10)				1,451	(238)	(14.10)	(238)	(14.10)
2015/16	1,719	0	(24)	0	1,695	0	1,695	1,388	(11)				1,412	(283)	(16.70)	(283)	(16.70)
2016/17	1,730	0	(24)	0	1,706	0	1,706	1,388	(11)				1,412	(294)	(17.20)	(294)	(17.20)
2017/18	1,741	0	(24)	0	1,717	0	1,717	1,388	(11)				1,412	(305)	(17.80)	(305)	(17.80)
2018/19	1,752	0	(24)	0	1,728	0	1,728	1,388	(11)	342 MW CT	342	0	1,753	25	1.40	25	1.40
2019/20	1,756	0	(24)	0	1,732	0	1,732	1,388	(11)				1,753	21	1.20	21	1.20
2020/21	1,773	0	(24)	0	1,749	0	1,749	1,388	(11)				1,753	4	0.20	4	0.20
2021/22	1,786	0	(24)	0	1,762	0	1,762	1,388	(11)				1,753	(9)	(0.50)	(9)	(0.50)
2022/23	1,793	0	(24)	0	1,769	0	1,769	1,382	(11)				1,747	(22)	(1.20)	(22)	(1.20)

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM initiatives.

(c) Includes companies MLR share of:
NCEMC sale, through 2009/10 (220 MW)

(d) Reflects the following Winter capability assumptions:
EFFICIENCY IMPROVEMENTS:
2008/09: Big Sandy 1: 0 MW (turbine)
2017/18 Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
SEPARATE INJECTION DERATES:
2014/15: Big Sandy 2: 25 MW
2022/23: Rockport 1: 41 MW
FGD DERATES:
2015/16: Big Sandy 2: 40 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2017/18: Rockport 1: 0 MW
2019/20: Rockport 2: 0 MW

(e) Includes companies MLR share of:
Sale of 100 MW to Wolverine thru 2009/10
Purchase from Constellation (315 MW), 2009/10 through 2011/12
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008/09 and 25 MW in 2009/10
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2013/14
RPM Auction Sales 2007/08 - 2011/12 (775 MW, 1408 MW, 1379 MW , 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) For PJM capacity planning purposes, new wind capacity value is assumed to be 13% of nameplate

Kentucky Power Company
Projected Summer Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2009 - 2023)
Per 2009 KPCO (and AEP-Eastern Zone) IRP

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
					=Sum(1-4)		=Sum(5-6)						=((8)-(9))+Sum(11)+(12)	=(13)-(5)	=(14)/(5)*100	=(13)-(7)	=(16)/(7)*100
	Peak Demand - MW							Capacity - MW						Reserve Margin - MW			
										Planned Capacity Additions							
Summer Season	Internal Demand (a)	Internal Wholesale Contracts	DSM (b)	Committed Sales (c)	Net Demand	Interruptible Demand	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Units	MW (f)	Annual Purchases	Total Capacity	Reserve Margin Before Interruptible	% of Internal Demand	Reserve Margin After Interruptible	% of Internal Demand
2009	1,308	0	0	15	1,323	0	1,323	1,452	80				1,372	49	3.70	49	3.70
2010	1,338	0	(18)	16	1,336	0	1,336	1,452	80				1,372	36	2.70	36	2.70
2011	1,357	0	(37)	0	1,320	0	1,320	1,452	73	50 MW Wind	6	0	1,385	65	4.90	65	4.90
2012	1,364	0	(49)	0	1,315	0	1,315	1,452	(2)	50 MW Wind	6	0	1,467	152	11.60	152	11.60
2013	1,379	0	(61)	0	1,318	0	1,318	1,452	(2)				1,467	149	11.30	149	11.30
2014	1,389	0	(74)	0	1,315	0	1,315	1,452	(2)				1,467	152	11.60	152	11.60
2015	1,400	0	(86)	0	1,314	0	1,314	1,387	(5)				1,405	91	6.90	91	6.90
2016	1,408	0	(86)	0	1,322	0	1,322	1,387	(5)				1,405	83	6.30	83	6.30
2017	1,420	0	(86)	0	1,334	0	1,334	1,388	(5)				1,406	72	5.40	72	5.40
2018	1,431	0	(86)	0	1,345	0	1,345	1,388	(5)	314 MW CT	314	0	1,720	375	27.90	375	27.90
2019	1,441	0	(86)	0	1,355	0	1,355	1,388	(5)				1,720	365	26.90	365	26.90
2020	1,448	0	(86)	0	1,362	0	1,362	1,388	(5)				1,720	358	26.30	358	26.30
2021	1,462	0	(86)	0	1,376	0	1,376	1,388	(5)				1,720	344	25.00	344	25.00
2022	1,474	0	(86)	0	1,388	0	1,388	1,388	(5)				1,720	332	23.90	332	23.90
2023	1,483	0	(86)	0	1,397	0	1,397	1,122	(5)	306 MW CC	306	0	1,759	362	25.90	362	25.90

Notes: (a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM initiatives.

(c) Includes companies MLR share of:
NCEMC sale, through 2010 (220 MW)

(d) Reflects the members ownership ratio of following summer capability assumptions:
EFFICIENCY IMPROVEMENTS:
2009: Big Sandy 1: 0 MW (turbine)
2017: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
SEPARATE INJECTION DERATES:
2015: Big Sandy 2: 25 MW
2023: Rockport 1: 41 MW
FGD DERATES:
2015: Big Sandy 2: 40 MW
2017: Rockport 1: 35 MW
2019: Rockport 2: 35 MW
SCR DERATES:
2017: Rockport 1: 0 MW
2019: Rockport 2: 0 MW
RETIREMENTS:
2023: 260 MW

(e) Includes companies MLR share of:
Sale of 50 MW to Wisconsin Public Service in 2007
Sale of 100 MW to Wolverine thru 2009
Purchase from Constellation (315 MW), 2009 through 2011
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008 and 25 MW in 2009
Sale of 22 MW from Tanners Ck. 4 in 2010-2014
RPM Auction Sales 2007-2011 (775 MW, 1408 MW, 1379 MW, 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) For PJM capacity planning purposes, new wind capacity value is assumed to be 13% of nameplate

AEP-System; AEP-Eastern Zone; Kentucky Power Company

CUMULATIVE Renewables Resources Required to Approach an Approximate 7% System "Target" by 2013 and 10% by 2020 [(a)]

That Would Be Reflective of Known or Emerging Federal or State-Specific Mandates

Per 2009 KPCO (AEP-Eastern Zone and AEP-Western [SPP] Zone) IRP

By 1/1/XX:	APCo Solar Nmplt (MW)	APCo Wind Nmplt (MW)	APCo Biomass Equiv (MW)	APCo Renewbl Percent of Sales	CSP Solar Nmplt (MW)	CSP Wind Nmplt (MW)	CSP Biomass Equiv (MW)	CSP Renewbl Percent of Sales	OPCo Solar Nmplt (MW)	OPCo Wind Nmplt (MW)	OPCo Biomass Equiv (MW)	OPCo Renewbl Percent of Sales
2009	0	75	0	0.8%	0	0	0	0.0%	0	0	0	0.0%
2010	0	276	0	2.5%	1	50	0	0.8%	2	50	0	0.6%
2011	0	551	0	4.5%	2	150	0	2.0%	4	175	10	2.0%
2012	0	751	8	6.2%	6	276	57	5.1%	9	400	45	4.9%
2013 (b)	0	851	8	6.9%	11	426	57	7.0%	17	550	45	6.4%
2014	0	851	8	6.9%	17	426	57	7.0%	25	550	45	6.4%
2015	0	851	8	6.9%	22	426	57	7.0%	34	550	102	7.6%
2016	0	851	8	6.8%	28	466	57	7.5%	42	550	102	7.6%
2017	0	851	8	7.0%	33	466	57	7.7%	50	550	102	7.7%
2018	0	851	8	6.7%	41	466	57	7.4%	59	550	229	10.3%
2019	0	851	50	7.4%	49	466	57	7.4%	69	550	315	12.0%
2020	0	851	50	7.3%	56	666	57	9.8%	78	550	315	12.0%

By 1/1/XX:	I&M Solar Nmplt (MW)	I&M Wind Nmplt (MW)	I&M Biomass Equiv (MW)	I&M Renewbl Percent of Sales	KPCo Solar Nmplt (MW)	KPCo Wind Nmplt (MW)	KPCo Biomass Equiv (MW)	KPCo Renewbl Percent of Sales	AEP-East Solar Nmplt (MW)	AEP-East Wind Nmplt (MW)	AEP-East Biomass Equiv(c) (MW)	AEP-East Renewbl Percent of Sales
2009	0	0	0	0.0%	0	0	0	0.0%	-	75	-	0.2%
2010	0	150	0	2.5%	0	0	0	0.0%	3	525	-	1.5%
2011	0	300	0	4.7%	0	50	0	1.9%	6	1,226	10	3.2%
2012	0	400	0	6.2%	0	100	0	3.8%	15	1,926	109	5.5%
2013 (b)	0	500	107	9.3%	0	100	19	4.6%	29	2,426	235	7.0%
2014	0	500	107	9.2%	0	100	19	4.6%	42	2,426	235	7.0%
2015	0	500	107	9.2%	0	100	112	12.1%	56	2,426	385	7.8%
2016	0	560	107	10.0%	0	100	112	12.0%	70	2,526	385	8.0%
2017	0	560	107	10.4%	0	100	112	11.9%	83	2,526	385	8.0%
2018	0	560	107	9.8%	0	100	112	11.8%	100	2,526	512	8.6%
2019	0	560	107	9.8%	0	100	112	11.7%	118	2,526	641	9.2%
2020	0	560	107	9.7%	0	100	112	11.7%	134	2,726	641	9.7%

Per "Table 2";
KPCo-WEAVER
Direct Testimony

By 1/1/XX:	PSO Solar Nmplt (MW)	PSO Wind Nmplt (MW)	PSO Biomass Equiv (MW)	PSO Renewbl Percent of Sales	SWEPCO Solar Nmplt (MW)	SWEPCO Wind Nmplt (MW)	SWEPCO Biomass Equiv (MW)	SWEPCO Renewbl Percent of Sales	AEP-West (SPP) Solar Nmplt (MW)	AEP-West (SPP) Wind Nmplt (MW)	AEP-West (SPP) Biomass Equiv(c) (MW)	AEP-West (SPP) Renewbl Percent of Sales
2009	0	393	0	9.4%	0	31	0	0.6%	0	424	0	5.0%
2010	0	393	0	9.0%	0	111	0	2.3%	0	503	0	5.6%
2011	0	591	0	13.3%	0	211	0	4.3%	0	801	0	8.6%
2012	0	591	0	12.8%	0	311	0	6.3%	0	901	0	9.5%
2013 (b)	0	591	0	12.7%	0	461	0	9.3%	0	1,051	0	10.9%
2014	0	591	0	12.6%	0	461	0	9.2%	0	1,051	0	10.9%
2015	0	658	0	14.0%	0	494	0	9.8%	0	1,151	0	11.8%
2016	0	658	0	13.9%	0	594	0	11.6%	0	1,251	0	12.7%
2017	0	858	0	18.0%	0	594	9	11.7%	0	1,451	9	14.7%
2018	0	858	0	17.9%	0	594	9	11.6%	0	1,451	9	14.6%
2019	0	858	0	17.8%	0	594	9	11.4%	0	1,451	9	14.5%
2020	0	1,058	0	21.8%	0	594	9	11.3%	0	1,651	9	16.3%

By 1/1/XX:	AEP System Solar Nmplt (MW)	AEP System Wind Nmplt (MW)	AEP System Biomass Equiv(c) (MW)	AEP System Renewbl Percent of Sales
2009	-	499	-	1.3%
2010	3	1,029	-	2.5%
2011	6	2,027	10	4.5%
2012	15	2,827	109	6.4%
2013 (b)	29	3,477	235	8.0%
2014	42	3,477	235	8.0%
2015	56	3,577	385	8.8%
2016	70	3,777	385	9.1%
2017	83	3,977	394	9.6%
2018	100	3,977	521	10.1%
2019	118	3,977	650	10.5%
2020	134	4,377	650	11.3%

(a) Data exclude pre-existing conventional (run-of-river) hydro energy as a renewable source as it has been excluded from proposed federal RPS criteria. Further, renewable target 'basis' (denominator) was subsequently *assumed to be reduced to include retail sales only based on emerging Federal proposed RPS/RES* legislation, whereas the initial target basis was presumed to include internal (retail and wholesale) sales.

(b) 2012/2013 represent the initial years for Federal RPS/RES mandates as currently proposed in legislation before Congress. Further, 2013 would represent the initial year after the potential expiration of federal Production Tax Credits (PTC) for, particularly, wind resources. Establishment of a federal renewables standard would likely eliminate further extension of such PTC opportunities.

(c) Biomass "equivalent" capacity considers--for 'co-firing' or 'separate injection' alternatives--the relative % of the generating capacity of the unit (being co-fired) equivalent to the relative amount of biomass feedstock, by MMBtu of heat content, in the combined fuel mix. In other words, if a 600 MW (nameplate) is co-fired with biomass and the relative heat content of the biomass is 2% of the combined fuels' heat content, then the "Biomass Equiv" capacity represented above would be 600 MW x 2%, or 12 MW.

Kentucky Power Company
Relative Change in Annual Revenue Requirement / Project Cost Comparison
Due to Proposed 100 MW LDWEC PPA
2010-2020

A	B	C	D	E	F	G	H	I	J
	KPCo / LDWEC Wind Capacity (Nameplate)	KPCo / LDWEC Wind Energy	LDWEC PPA Cost	<Avoided> Variable Costs, including AEP-Pool Energy Settlements	<Avoided> Pool Capacity Settlement Costs	D+E+F = KPCO (Total Co.) (Net) Revenue Requirement Change re: LDWEC Project (1) (2)	KPCO Internal Load	G / H x 100 = KPCo Relative (Net) Revenue Requirement (3)	10+ Year Average (2010-2020)
	MW	GWh	($M)	($M)	($M)	($M)	(GWh)	(¢/kWh)	(¢/kWh)
		CONFIDENTIAL COMPONENTS							
2010 (5)	100					2.8	4,041 (5)	0.070	
2011	100					6.4	8,286	0.077	
2012	100					6.6	8,354	0.078	
2013	100					6.5	8,417	0.077	
2014	100					6.2	8,472	0.074	
2015	100					6.5	8,530	0.077	
2016	100					6.6	8,593	0.076	
2017	100					6.2	8,651	0.071	
2018	100					5.2	8,707	0.060	
2019	100					4.8	8,762	0.055	
2020	100					5.4	8,816	0.061	0.071

K	L	M
	G x 1000/C = LDWEC (Net) Cost per Mwh of Wind Generated	versus... Estimated Cost of RECs (4)
	(per MWh)	(per ~MWh)
	CONFIDENTIAL COMPONENTS	
2010 (5)		
2011		
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		

LDWEC Project "Proxy"...
IF FUTURE Wind Contracts (Post-2012) were to exclude 'Pass-thru' of Federal PTCs (@ ~$30/Mwh)

2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		

Notes:
(1) (Net) Revenue Requirement determination excludes the monetization (credit to revenue requirement) of any RECs received under the assumption they would ultimately be required to be utilized/retired to achieve a potential
Also, reflects a KPCo 'Total Company' (retail and wholesale) perspective
(2) Assumed if wind PPAs not assigned to KPCo, would be assigned to another AEP (Pool) Member Company, so there would be no incremental MLR-related (Off-System) revenues
(3) As a function of KPCo annual (internal) net energy requirement.
(4) National REC estimates (nominal) per AEP Strategic and Economic Analysis (H209 'SEA' Case)
(5) Assumes PPA start date of July 1, 2010.... therefore for 2010 'Relative (Net) Revenue Requirement' purposes, only Jul-Dec 2010 KPCo Internal Load reflected
(6) Although numerous regional/state REC markets exist *today*, assumes a fungible 'national' REC markets would be established in parallel with passage of a Federal RPS

Column Definitions:
D. LDWEC PPA Cost - represents 3rd-party purchase costs under the 100 MW LDWEC PPA, and based on projected generation profiles for the LDWEC project
E. Variable Cost including AEP-Pool Energy Settlements - primarily fuel costs that are estimated to be offset by wind energy, as well as change in Primary (inter-co) sales to/from AEP Pool cos
F. Pool Capacity Settlement Charges - represents reduced capacity payments to other AEP Member Companies due to the assumed capacity value of PPA assigned to KPCo
H. Net Revenue Requirement Change - is the sum of columns D through F
I. KPCo Relative Net Revenue Requirement - represents the average incremental costs of the LDWEC Project --in cents/kWh-- based on (divided by) KPCo's internal energy requirements
J. Represents the (simple) average (Net) Revenue Requirement impact of the LDWEC Project in cents/kWh over the 2010-2020 period
L. Represents the annual (Net) Cost of the LDWEC project based on (divided by) the corresponding annual estimated wind generated by that project

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
RANIE K. WOHNHAS

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

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**DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A: My name is Ranie K. Wohnhas. My position is Director, Business Operations Support, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I received a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power in 1978 working in various customer services and accounting positions. In 1983, I transferred to Kentucky Power Company working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 overseeing all billing and collection activity for the Company. In 1998, I transferred to Appalachian Power Company working in rates. In 2001, I transferred to the AEP Service Corporation working as a Senior Rate Consultant. In July 2004, I assumed the position of Manager, Business Operations Support and was promoted to Director in April 2006.

Q: WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, BUSINESS OPERATIONS SUPPORT?

A: I am responsible for the coordination of the Company's financial operating plans including an operational interface with all other AEP organizations impacting KPCo results. This includes advising the President of KPCo concerning the financial effect of all business activities affecting the performance of businesses within the President's responsibilities. One of my primary responsibilities is the preparation, coordination and monitoring of all the Company's yearly budgeting processes and analyses of variances to those budgets.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I have testified before this Commission in one fuel review proceeding and filed testimony in the Company's last rate case filing 2005-00341.

III. PURPOSE OF TESTIMONY

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

A: I am sponsoring the Company's test year results of operations for the twelve months ended September 30, 2009 contained in Section IV. I am supporting two Rate Base adjustments, and seventeen proposed rate case adjustments to Net Electric Operating Income (NEOI) as included in Section V, Workpaper S-4.

Q: PLEASE DESCRIBE SECTION IV OF THE COMPANY'S FILING.

A: Section IV of the Company's filing is the financial exhibit required by the Commission regulation in 807 KAR 5:001, Section 6. Balance sheet data is shown as of September 30, 2009 and income statement data is for the twelve months ended September 30, 2009. This complies with the ninety-day rule stipulated by the Commission in Section 6.

Q: HAS THE COMPANY COMPLIED WITH THE COMMISSION'S REGULATIONS REQUIRING CERTAIN ADDITIONAL DATA TO BE FILED?

A: Yes. This information has been incorporated into Section II of the Company's filing.

Q: HAVE YOU PREPARED ANY SCHEDULES OR WORKPAPERS IN CONNECTION WITH YOUR TESTIMONY?

A: Yes. The summaries and details of the Capitalization and Rate Base amounts, and the adjustments to the "per books" results of operations that I am sponsoring are set forth in various schedules of Section V of the Company's filing. I will identify the specific schedule and page reference number in describing each summary of the proposed adjustment.

Q: WHAT INFORMATION ON THE SUMMARIES AND ADJUSTMENTS ARE YOU SPONSORING?

A: I am responsible for the total Company amounts shown or used to derive the KPCo retail jurisdictional amounts. Witness Wagner furnished the KPCo retail jurisdictional amounts and the allocation factors required to calculate such amounts. Witness Wagner also is responsible for the allocation methodology.

IV. ADJUSTMENTS TO RATE BASE

Q: PLEASE DESCRIBE THE ADJUSTMENTS TO THE SEPTEMBER 30, 2009 RATE BASE BALANCES THAT YOU ARE SPONSORING.

A: Schedule 5 of Section V (lines 18-28) summarizes, by Rate Base component, the adjustments to Rate Base that I am supporting.

<u>Electric Plant In Service (EPIS)- Net (Line 20)</u>

Electric Plant In Service – Net has been decreased by $4,276,291 (Schedule 13, Column 3, Lines 9-12) to reflect three adjustments: (a) the inclusion of net Post In Service AFUDC and Deferred Depreciation Expense on the Hanging Rock-Jefferson 765KV line that was approved by the Commission in its Order in Case No. 9061 ($1,020,151); (b) the elimination of the effect of capitalized leases recorded in EPIS, for financial reporting purposes only, as required by the Financial Accounting Standards Board (FASB) No. 71 ($1,959,020); and (c) the elimination of the recovery of an Asset Retirement Obligation from rate base ($3,337,422). Witness Wagner supports the adjustment to recover the Asset Retirement Obligation as shown in Section V, Workpaper S-4, Page 29.

<u>Plant Held for Future Use – Carrs Site (Line 21)</u>

Plant Held for Future Use has been decreased by $6,778,355 (Schedule 14, Column 3, Line 5) to remove the Carrs Site, as is supported by the testimony of Witness Wagner in his adjustments to Capitalization.

Q: ARE THERE ANY OTHER ADJUSTMENTS TO RATE BASE BEING PROPOSED BY THE COMPANY?

A: Yes. The other adjustments to Rate Base are summarized on Schedule 4, Page 1, Column 4 (lines 15-25) of Section V. The first adjustment is to increase EPIS – Gross by $9,422,784 for additional capital investment for service reliability purposes, which Witnesses Phillips and Wagner support. The next adjustment is to increase Accumulated Provision For Depreciation by $12,484,677 for various depreciation expense adjustments supported by Witnesses Henderson and

Wagner. KPCo is proposing an adjustment to increase Prepayments by $15,390,035 to address the pre-funding status of its qualified pension plan as described and supported by Witness McCoy. KPCo also proposes reducing the Materials and Supplies for the Big Sandy Coal Stock Adjustment by $21,230,418, which Witness Wagner describes as an adjustment to Capitalization. The other adjustments relate to an increase in Cash Working Capital of $8,197,233, the details of which are set forth by individual Operating Expense adjustments, on Pages 3-9 of Schedule 4 of Section V.

V. RATE CASE ADJUSTMENTS TO NEOI

Q: WOULD YOU DESCRIBE EACH OF THE PROPOSED RATE CASE ADJUSTMENTS TO NEOI THAT YOU ARE SUPPORTING?

A: Yes.

Interest on Customer Deposits (Section V, Workpaper S-4, Page 1)

Customer deposits have been included in this case as a reduction to the Company's Rate Base. This recognizes that customer deposits, similar to customer advances for construction, are a source of funds to the Company. Unlike customer advances for construction however, interest is paid to customers for customer deposits at a rate of 6% per annum. Consistent with the treatment of this interest allowed by the Commission in Case No. 9061, an adjustment has been made to increase test year expenses by $1,039,163.

Incentive Plan Adjustment (Section V, Workpaper S-4, Page 13)

Employees are compensated through a combination of base pay and incentive pay programs. As explained by Witness Jolley, the Incentive Compensation Plan

(ICP) and Long Term Incentive Plan (LTIP) programs have a target payout amount (1.0) with upper (2.0) and lower (0.0) thresholds for employee payout. Exhibit RKW-1 shows an adjustment to the target payout level (1.0) of $1,250,118 and $897,279 for ICP and LTIP respectively, for a total adjustment of $2,147,397. The proposed adjustment of the test year incentive expense to an amount equal to the 1.0 target level is known and measureable. Not only is 1.0 a target, but in each of the three calendar years prior to 2009 the Company's ICP expense exceeded the 1.0 target.

	2006	2007	2008	Average
Actual ICP Compensation	$5,973,598	$6,920,627	$8,122,023	$7,005,416
ICP Adjusted to 1.0 Target Level	$3,801,682	$4,262,478	$5,576,066	$4,457,409

The jurisdictional increase in O&M related incentives compensation expense is $1,399,386 bringing the test year level to the target level in cost of service.

Normalization Major Storms Adjustment (Section V, Workpaper S-4, Page 15)

The Company adjusted its test year storm damage expense, less straight time labor, by using a three year average storm damage expense, less straight time labor, adjusted by the Handy-Whitman Contract Labor Index. Using the three year average and deducting the test year level of storm damage expense results in a decrease adjustment of $1,201,007. Three major storms (January 27, 2009 ice storm, February 11, 2009 wind storm and May 8, 2009 thunderstorm) are excluded from this normalization adjustment. The amortization of storm cost deferral related to these three major storms is shown as a separate adjustment in Section V, Workpaper S-4, Page 20.

AFUDC Offset Adjustment (Section V, Workpaper S-4, Page 19)

The September 30, 2009 balance of Construction Work In Progress (CWIP) was used in the determination of Rate Base. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction (AFUDC) "offset" adjustment is being made to record AFUDC above the line. The CWIP balance was $28,208,039 at September 30, 2009 of which $2,426,699 is not subject to AFUDC. The remaining balance of $25,781,340 is subject to AFUDC. Using the requested overall return of 8.67%, the annualized AFUDC is $2,235,242. The AFUDC booked during the test year was $1,036,657 requiring an adjustment to increase the AFUDC offset by $1,198,585. The Deferred Federal Income Taxes (DFIT) associated with the borrowed funds portion of the $2,235,242 is $327,564. The booked DFIT on the borrowed funds portion was $285,161. This increases DFIT by $42,403. The net effect on NEOI is a jurisdictional decrease of $42,021.

Amortization Storm Cost Deferral (Section V, Workpaper S-4, Page 20)

On August 31, 2009, the Company filed an application with the Kentucky Public Service Commission requesting authorization in accordance with SFAS No. 71 to accumulate and defer for review and recovery in the Company's next base rate proceeding incremental and extraordinary O&M expenses incurred by the Company in repairing damage and restoring service in connection with three

2009 Major Event storms. The Company also requested relief by Order dated on or before December 31, 2009.

The adjustment reflects the amortization of the three 2009 Major Event storms over a three year period. This increases jurisdictional O&M expenses by $3,404,490.

Annualization Postage Increase (Section V, Workpaper S-4, Page 21)

The test year adjustment for postage expense annualizes the United States Postal Service (USPS) 4.76 percent across the board increase that went into effect on May 11, 2009. To reflect this increased cost, the number of bills, notices, letters, etc. (See Exhibit RKW-2) mailed by the Company from October 1, 2008 through May 8, 2009 was multiplied by the postage rate increase resulting in an increase to Operation and Maintenance (O&M) Expenses of $22,626.

O&M Adjustment Advertising (Section V, Workpaper S-4, Page 28)

A review was made of advertising expenses recorded during the test year. This adjustment eliminates pursuant to Commission regulation 807 KAR 5:016 Section 4(1) those expenses ($18,297) that were promotional and institutional advertising.

Annualization Property Tax Expense (Section V, Workpaper S-4, Page 30)

Property tax expense reflected in the test year is based upon the actual property investment at December 31, 2008 and property tax rates for 2009. This adjustment increases property taxes by a jurisdictional amount of $162,360 to reflect increased property tax expense using the estimated 2010 property taxes on the December 31, 2009 assessable property value and the latest actual property rate.

Annualization Employee Related Expenses (Section V, Workpaper S-4, Pages 32-38)

During the test year, wage increases were granted, employee benefit plan costs escalated, and payroll related taxes increased. Page 32 of Workpaper S-4 summarizes this adjustment, which increases jurisdictional O&M Expenses by $687,924 and Taxes Other Than Income Taxes by $54,528 to annualize the test year increases in labor and other employee related expenses incurred by the Company during the test year. Pages 33-38 of Workpaper S-4 provide further details supporting the adjustment.

The annualization of wages and salary increases, medical plan costs, life insurance costs, dental plan costs, long term disability insurance costs and savings plan costs were done to reflect the ongoing level of expense at the end of the test year period.

The annualization of Federal Insurance Contributions Act (FICA) tax expense reflects the wage and salary increases to the Old Age Survivors & Disability Insurance (OASDI) and Medicare rates and employee maximum base.

Annualized Lease Expense (Section V, Workpaper S-4, Page 39)

The test year adjustment of lease costs annualizes the current level (September 2009) of lease rental expense and results in a decrease in the jurisdictional O&M expense by $69,186.

Eliminate Safety Focus Costs (Section V, Workpaper S-4, Page 40

At the end of 2008, with a payout in February 2009, the Company eliminated the safety focus incentive plan. The adjustment reflects this elimination by reducing the test year jurisdictional O&M expense by $208,239.

Adjustment Interest Synchronization (Section V, Workpaper S-4, Page 42)

The purpose of this adjustment is to reflect in the computation of Federal and State Income Taxes included in the test period cost of service and the interest expense tax deduction that will result based upon the capital costs and capital structure included by the Company in this filing.

The annualized interest expense has been computed using long-term and short-term debt capital at a cost of 6.48% and 2.29% respectively, as proposed in the overall cost of capital. These capital components and cost rates yield a pro forma interest expense deduction of $34,710,974 (Line 7). This amount is representative of the tax deductible interest costs the Company will incur assuming the capital structure and related capital costs proposed by the Company.

The actual interest expense incurred during the test year was $37,783,905 (Line 8). In computing state income tax for the test year, the jurisdictional interest expense adjustment of ($2,732,876) (Line 11) is the difference between the pro forma interest and actual interest multiplied by the state income tax rate of 6.2282%. This results in an increase of test year state income tax of $170,209.

Federal income taxes have been synchronized using the jurisdictional interest expense adjustment of ($2,732,876) (Line 11) which is the difference between the pro forma interest and actual interest, plus the $170,209 (Line 13) state tax effect.

The net change of ($2,562,667) (Line 14) at a 35% tax rate yields an increase to FIT of $896,933 (Line 16).

Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A: Yes.

AFFIDAVIT

Ranie K. Wohnhas, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Ranie K. Wohnhas

Ranie K. Wohnhas

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Ranie K. Wohnhas this 18th day of December 2009.

Judy K. Kosquist

Notary Public

My Commission Expires January 23, 2013

Kentucky Power Company
Summary of ICP/LTIP Adjustment to 1.0 Target Payout
Test Year 12ME 9/30/2009

Type of Incentive	Calculated Incentive @ 1.0 Payout	Test Year Incentive	Adjustment
ICP			
KPCo Employees	$ 2,658,577	$ 2,263,062	$ 395,515
AEPSC Employees	$ 2,992,070	$ 2,137,467	$ 854,603
Total ICP	$ 5,650,647	$ 4,400,529	$ 1,250,118
LTIP			
KPCo Employees	$ 206,705	$ 85,422	$ 121,283
AEPSC Employees	$ 784,153	$ 8,157	$ 775,996
Total LTIP	$ 990,858	$ 93,579	$ 897,279
Total ICP/LTIP	$ 6,641,505	$ 4,494,108	$ 2,147,397

Exhibit RKW-2

Kentucky Power Company
Number of Bills, Notices, Letters, etc. Mailed October 1, 2008 through May 8, 2009

Month	Bills	Disconnects	W-2's	Payroll Checks	Accts Pay Checks	Refund Checks	Total
October 08	184,336	17,983		86	463	944	203,812
November	183,957	19,588		86	391	870	204,892
December	182,516	22,539		86	508	690	206,339
January 09	181,718	24,692	519	172	346	550	207,997
February	185,333	23,271		86	375	490	209,555
March	182,592	21,538		86	344	740	205,300
April	184,773	22,282		86	342	707	208,190
May 1 - May 8	55,456	6,510		86	107	141	62,300
Total	1,340,681	158,403	519	774	2,876	5,132	1,508,385