Exhibit No.:
Issue: Fuel Expense, Purchased Power Expense, Off-System Sales and Transmission Service Costs
Witness: Burton L. Crawford
Type of Exhibit: Direct Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No.: ER-2012-0174
Date Testimony Prepared: February 27, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2012-0174

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
February 2012

"[redacted]**" Designates "Highly Confidential" Information Has Been Removed.**
Certain Schedules Attached To This Testimony Designated "(HC)" Have Been Removed
Pursuant To 4 CSR 240-2.135.

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

Case No. ER-2012-0174

Q: Please state your name and business address.

A: My name is Burton L. Crawford. My business address is 1200 Main, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or the "Company") as Director, Energy Resource Management.

Q: What are your responsibilities?

A: My responsibilities include managing the Energy Resource Management ("ERM") department. Activities of ERM include resource planning, wholesale energy purchase and sales evaluations, Supply division budgeting, and capital project evaluations.

Q: Please describe your education, experience and employment history.

A: I hold a Master of Business Administration from Rockhurst College and a Bachelor of Science in Mechanical Engineering from the University of Missouri. Within KCP&L, I have served in various areas including regulatory, economic research, and power engineering starting in 1988.

Q: Have you previously testified in a proceeding at the Missouri Public Service Commission ("MPSC" or "Commission") or before any other utility regulatory agency?

A: Yes, I have. I provided testimony to the Commission in KCP&L's most recent Missouri rate cases and in a variety of other proceedings. I have also appeared before the Kansas Corporation Commission on behalf of KCP&L.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the level of fuel expense, purchased power expense and the wholesale contract customer revenues filed in the Direct Testimony of Company witness John P. Weisensee. I also discuss adjustments to the projected off-system sales margins for purchases for resale, Southwest Power Pool ("SPP") line loss charges and Revenue Neutrality Uplift ("RNU") charges. In addition, I will provide information regarding the requirements necessary to support an Electric Utility Fuel and Purchased Power Cost Recovery Mechanism related to the Company's request for an Interim Energy Charge ("IEC"). I specifically address all or a portion of the requirements of 4 CSR 240-3.161(2)(O), (P), (Q) and (R).

I. ENERGY PRICE FORECASTS

Q: Please describe how KCP&L forecasts electricity prices?

A: KCP&L utilizes the MIDAS™ model, which is similar to other fundamental price forecasting models that are commonly used in the industry. MIDAS™ is provided by Ventyx (formerly Global Energy). The Transact Analyst™ component of MIDAS™ generates regional prices by modeling power flows within and between various energy markets, transaction areas, North American Electric Reliability Corporation ("NERC")

Sub-Regions, and NERC Regions. Power flows are determined based on the relative loads, resources, marginal costs, transactions costs, and intertie limits between the areas or regions. Transactions occur on an hourly basis for 8,760 hours per year.

Q: What are the primary inputs to the model?

A: The model utilizes a sizeable input dataset, referred to as the National Database. It is populated with assumptions about market supply, demand, and transmission. The bulk of the input assumptions use Federal Energy Regulatory Commission Form 1 data, Energy Information Administration 411 reports, and Continuous Emissions Monitoring system data compiled by the Environmental Protection Agency ("EPA"), as their sources. The demand data includes projected hourly demand for virtually every utility in the Eastern Interconnect. The supply data contains a representation of all generating units within those utilities: capacity, heat rate, fuel type, variable operations and maintenance costs, outage rates, emissions rates, start-up costs, etc. Fuel costs may also be tied to individual units based on reported costs. This applies primarily in the case of nuclear and coal units, whose fuel costs would not be tied to a national commodity price such as is the case with natural gas or fuel oil. The other primary inputs are: natural gas prices, natural gas basis adders, fuel oil prices, and emission allowance prices. These inputs are more "global" in nature, meaning they are not tied to specific units. The dataset also includes transmission constraints between the areas. Ventyx, the provider of the National Database, arrives at the constraints through their analyses of regional assessments from the various regional entities affiliated with the NERC.

Q: How does the model use this data to forecast power prices?

A: The model performs an hourly chronological dispatch of all generation resources to meet projected hourly demand in each region, as defined in the model's geographic topology. For each hour, the last generator needed to meet demand is identified as the marginal unit. All of the costs associated with dispatching the marginal unit become the basis for the price in that hour in that region.

Q: Is this done for only one region?

A: No. Our market simulations model most of the Eastern Interconnect. As a result, the unit identified as marginal may be dispatched in order to serve load in a neighboring region. The model will perform transactions between regions, as long as adequate transmission capacity still exists. If transmission becomes constrained between regions before all of the economical transactions have been completed, the model's bidding logic will arrive at an appropriate price spread between the two regions.

Q: What is your opinion of the resulting forecasts?

A: The fundamental supply and demand data are relatively good. That is, the demand forecast from utilities and the existing public data on installed generation capacity are sufficiently reliable, so that identifying a reasonable unit to base an hourly price on is something that can be done with a reasonable degree of confidence. The input assumption that creates a larger challenge is fuel price. In KCP&L's market area, the market price is almost always set by one of two fuels: coal or natural gas. Primarily, it is natural gas. Fuel oil might set the price of power in a very small number of hours in some years in the North SPP region.

Q: How difficult is it to predict the price of coal and natural gas?

A: Coal prices are relatively less volatile and the model inputs are based on actual reported fuel costs, so the impact of coal on power prices can be forecast with relative accuracy when coal is the marginal fuel. Natural gas prices are much more volatile and difficult to predict.

Q: How accurate are the power price forecasts?

A: The power price forecasts are relatively accurate when the fuel price forecasts are accurate, more specifically, when the natural gas price forecast is accurate. Natural gas is the marginal fuel in North SPP more than 50% of the hours in a year, so there is a strong correlation between natural gas and power in those hours. Schedule BLC-1 (HC) shows how closely KCP&L's power price forecast tracked prices that we observed in the North SPP market. It is a backcast of 2011 using the average spot gas price for each month. It is worth noting that in the modeling KCP&L uses one gas price for each month of the forecast period, although, in reality, the gas price can change every day. To the extent that gas prices were more volatile intra-month, that would affect our ability to track actual market prices with our backcast. Schedule BLC-2 illustrates the monthly volatility of natural gas in 2011. In addition to intra-month gas prices, hourly demand would influence our backcast versus the actual market. Because actual hourly demand data for 2011 is not yet available, our backcast uses the forecasted hourly demand that is part of the National Database that I discussed earlier.

Q: How are these market prices used in this case?

A: These market prices are used to normalize purchased power and fuel expense.

II. PURCHASED POWER AND FUEL NORMALIZATION

Q: What method for normalizing the test year fuel and purchased power expense did you use in this case?

A: The proper method for normalizing the test year fuel and purchased power expense is to normalize and annualize the system peak and energy, the market price of purchased power, the prices paid for fuel, generating system maintenance and forced outages, and available generating resources. After determining the appropriate normalized and annualized values, an accurate production cost computer modeling tool is used to develop the appropriate generation and purchased power levels, and resulting fuel and purchased power expenses. KCP&L used the MIDAS^{TM} model for its production cost model.

Q: Please describe the MIDAS^{TM} model used in this normalization.

A: This is the same modeling software used to generate the market price forecasts described previously. For purposes of running the production cost modeling used in this normalization, the model was run in "Price Mode" which means that the user inputs the market prices into the model, rather than using the model to generate the prices. The prices input into the model were the prices generated by the previously described price forecasting process. The model performs an economic dispatch of the Company's generating units and available market purchases in order to serve load in a least cost manner. The Company uses this model for various purposes, such as generating market price forecasts, long-term resource planning decisions, fuel and interchange budgeting, purchase and sales analysis, and other purposes.

Q: Please describe the normalization of the system requirements for this rate case.

A: KCP&L's native load was adjusted to reflect weather normalized and annualized customer growth by the Company's load forecasting personnel. This process is described in more detail in the Direct Testimony of Company witness George M. McCollister. This resulted in revised monthly peak demands and energy requirements, which were input into the MIDAS™ program. The program distributed the monthly energy requirements on an hourly basis. The software uses the normalized monthly energy and peaks, and the actual historical hourly system loads to shape the normalized loads on an hourly basis. The resulting load shape was then used in the normalized production cost modeling.

The Company's wholesale contract customers have been added to the native load to arrive at the total system requirements.

Q: Please describe these wholesale contract customers.

A: These are capacity and energy sales to City Utilities of Springfield, Independence Power and Light (a small load regulation contract) and the City of Chanute, Kansas. The revenue for these transactions and the associated fuel expense is included in Schedule BLC-4. They are not included in the off-system sales described in the Direct Testimony of Company witness Michael M. Schnitzer.

Q: Please describe the fuel price normalization.

A: The normalized fuel prices used in the modeling were developed by Company witness Wm. Edward Blunk and are described in detail in his Direct Testimony. These fuel prices were input into the model on a plant-specific basis and then were used in the normalized production cost modeling. The natural gas prices provided by Mr. Blunk were also used in the process of generating wholesale energy market prices.

Q: Please describe the maintenance outages normalization.

A: The Company performs scheduled maintenance on the base load generating units on a cyclical basis over a number of years. That is to say, a specific unit in any given year may have an extended turbine generator outage, a shorter boiler outage, a short inspection outage or no outage at all. In addition, refueling and maintenance outages at the Wolf Creek nuclear plant near Burlington, Kansas occur every eighteen months, either in the spring or the fall. Thus, in every third year Wolf Creek is available for generation for the entire year. Consequently, in any specific year, there may be higher or lower scheduled maintenance outages than the long-term average maintenance outages. In order to normalize the availability of the generating resources for the test year, we computed the total number of weeks that a unit would be scheduled for maintenance over the cycle and averaged this amount by the number of years in the maintenance cycle. These normalized maintenance outage assumptions were then spread over the test year to develop a test year maintenance schedule. These outages were scheduled so that no two units would be out at the same time and that all the base load generating resources would be available during the peak load periods of June through September. Schedule BLC-3 (HC) contains the maintenance schedule that was used for the normalization.

Q: Please describe the generating resources' available capacity normalization.

A: The generating resources available in the rate case modeling are the same as the Company's existing resources with adjustments made to normalize the capacity to the levels that are expected to be in place and operational as of August 31, 2012. First, long-term purchased power contract levels were adjusted to reflect the capacity levels that are committed effective August 31, 2012.

Q: How was the generation from renewable resources modeled in this rate case?

A: The existing wind generation from the Spearville Wind Energy Facility owned by KCP&L was modeled based upon the projected typical weekly energy output derived from actual wind profile data. Additional wind generation resources have been included in the modeling as purchased power agreements from resources that are expected to be added prior to August 31, 2012. The generation levels and energy prices are based upon signed contracts.

Q: How accurate are the results of this modeling?

A: After making the normalization adjustments described previously, we believe that the results of this modeling should likewise result in reasonably accurate results.

Q: For the test period, what expense items, if any, were adjusted as a result of normalizing fuel and purchased power expense?

A: Adjustments were made to the fuel costs to reflect both the normalized fuel market and normalized generation levels. Also, purchased power expense was adjusted to reflect the changes in the quantity of energy purchased and the price of such purchases. Schedule BLC-4 (HC) shows the generation levels by resource type and the purchased power levels, the costs of each, and the revenues from the wholesale contract customers. The adjustments are reflected in Schedule JPW-4, attached to the Direct Testimony of Company witness John P. Weisensee (adjustments CS-24 and 25).

III. ADJUSTMENTS TO THE PROJECTED OFF-SYSTEM SALES MARGINS

Q: Does KCP&L propose any adjustments to the amount of off-system sales margins computed by Company witness Michael M. Schnitzer?

A: Yes. KCP&L has included an adjustment to the computed 40th percentile of off-system sales margins in order to recognize the impact of the Purchases for Resale transactions in the computation of the Company's actual off-system sales margins.

Q: What are Purchases for Resale?

A: At a high level, these transactions represent KCP&L wholesale sales that are supplied by purchased power as compared to wholesale sales supplied by KCP&L owned generation.

Q: Please provide more detail.

A: In this case, we have classified four categories of Purchases for Resale. They are as follows:

(1) Transactions where a sale to the SPP Energy Imbalance Service ("EIS") market was supplied by a bilateral (wholesale) purchase. These are shown as Transaction Type 1 in Schedule BLC-5. These transactions began in February 2007 with the implementation of the SPP EIS market.

(2) Transactions where a bilateral sale was supplied by a bilateral purchase. KCP&L makes purchases on a day-ahead basis based upon its expected loads, the availability of firm transmission for purchases, the availability and price of energy for purchase, and generating resource availability. KCP&L makes these purchases to limit its exposure to risks posed by the real-time, hourly spot market and the availability of firm transmission on a real-time, hourly basis. These types of transactions are typically made with the intent to serve KCP&L's estimated

load obligations. However, not all of the energy purchased was required to meet actual needs in real time and, therefore, a portion is sold wholesale. These are shown as Transaction Type 2 in Schedule BLC-5.

(3) Transactions where a sale to the SPP EIS market was supplied by an SPP EIS market purchase. These transactions are typically the result of imbalances between KCP&L forecasted and actual generation, as KCP&L does not intentionally purchase from the SPP EIS market and then simultaneously sell the energy back to the SPP EIS market at another location. An example of this type of transaction is when KCP&L's actual hourly energy production at one generator is greater than scheduled, thus creating a sale to the SPP EIS market, while energy production at another KCP&L generator is less than scheduled, thus creating a purchase from the SPP EIS market. These are shown as Transaction Type 3 in Schedule BLC-5.

(4) Transactions where a bilateral sale was supplied by an SPP EIS market purchase. These are shown as Transaction Type 4 in Schedule BLC-5.

Q: Why is it appropriate to include these transactions in the off-system sales margin?

A: In the normal course of ensuring that adequate energy is reliably available in real time to meet all KCP&L energy obligations, KCP&L engages in all four of these wholesale transactions. The costs and benefits of these transactions are not reflected in the off-system sales margin analysis performed by Company witness Michael M. Schnitzer. Mr. Schnitzer's analysis reflects the sales made from KCP&L's generating and contracted resources. Without this adjustment, the revenue and costs associated with Purchases for Resale would not be recognized in the cost of service.

Q: What is the basis for the net amount of Purchases for Resale included in this case?

A: The amount of Purchases for Resale included in this case is based on actual Purchases for Resale for the 12 months ending October 2011. These actual amounts are shown in Schedule BLC-5.

Q: In KCP&L's last rate case did the Commission approve these recommended adjustments relating to Purchases for Resale?

A: Yes, the Commission approved these adjustments, which I recommended and Staff did not oppose, in its Report and Order of April 12, 2011 in the Company's last general rate case, Case No. ER-2010-0355.

Q: When calculating the actual level of off-system sale margins achieved, will Purchases for Resale be included as part of any true-up process?

A: Yes. KCP&L proposes to include Purchases for Resale in the calculation of actual off-system sales margin.

Q: How does KCP&L calculate actual off-system sales margins?

A: Actual off-system sales margins are determined by subtracting from off-system sales revenue the fuel and purchased power costs that supported those sales.

Q: How does KCP&L determine fuel and purchased power costs that support off-system sales?

A: KCP&L uses a computer program called Post Analysis ("PA") to determine the sources of energy used to support the off-system sales. Data on actual generation availability (by generating plant) and actual purchased power transactions are input to the model as potential sources of energy available to support off-system sales. Data on actual wholesale sales transactions are also entered.

The PA program then uses a re-dispatch algorithm to determine the incremental effect of each wholesale sale on generation and purchased power. This process generally results in the highest cost available sources of energy (either generation or purchased power) being assigned to support off-system sales and the lowest cost available sources of energy being assigned to serve KCP&L's native load requirements. This process is performed for each historical hour.

Once the allocation process is complete, the results indicate which generating plants and purchased power transactions were used to supply off-system sales in any given historical hour. Average fuel costs by plant are matched with the amount of energy produced by each plant (as determined by PA) to determine fuel cost to support off-system sales. Fuel cost is combined with the cost of purchased power (as determined by PA) to determine the total cost to supply off-system sales.

Q: **Is this methodology for calculating actual off-system sales margins consistent with the methodology used by Company witness Michael M. Schnitzer to determine the off-system sales margins in the current case?**

A: Yes, but only for sales made from KCP&L's generating plants. Mr. Schnitzer's off-system sales margin computation does not take into account the cost or revenues associated with Purchases for Resale transactions.

Q: **How does the SPP EIS market impact the calculation of KCP&L's off-system sales margins?**

A: The extremely large volume of balancing transactions caused by the implementation of the SPP EIS market in February, 2007 are allocated in large part to wholesale sales by the PA computer model for purposes of calculating margins.

Q: Please describe the effect of the SPP EIS market on off-system sales.

A: The SPP EIS market is based on the concept of "imbalances." Any difference between actual generation output and scheduled generation output is considered an imbalance that is financially settled through the SPP EIS market. For example, if a generator is scheduled to produce 100 MWhs in a given hour, but actually produces 101 MWhs, SPP will pay the generator for the additional 1 MWh of generation based on the market price of energy for that hour and geographic location. This creates a 1 MWh sale to SPP. If in this example the generator only produced 99 MWhs for the hour, SPP would charge the generator for the 1 MWh not produced. This creates a 1 MWh purchase from SPP. Prior to the SPP EIS market operation, this over- and under-generation did not create a wholesale transaction. Each of these SPP EIS market transactions, both purchases and sales, are included in the PA allocation process.

Q: Does KCP&L propose any other adjustments to the amount of off-system sales margins computed by Company witness Michael M. Schnitzer?

A: In addition to the Purchases for Resale adjustment, KCP&L has included SPP line loss charges and the net SPP RNU charges as an adjustment to the off-system sales margin.

Q: What are SPP line loss charges?

A: The SPP assesses a charge on wholesale energy transactions that exit the SPP EIS market footprint. This charge is to compensate transmission owners for transmission system energy losses. These losses are a result of physical power flows over the transmission system. KCP&L pays these line loss charges on a portion of its off-system sales. In addition, KCP&L receives a share of the loss charges collected from SPP.

Q: Why is it appropriate that KCP&L adjust the off-system sales margins for SPP line loss charges?

A: KCP&L pays these line loss charges on a portion of its off-system sales. As such, this is an expense related to off-system sales transactions. The model used by Company witness Michael M. Schnitzer for determining the off-system sales margins assumes the sales are made at the generator bus; therefore, the SPP line loss charges are not included.

Q: What is the basis of the SPP line loss charge amount included in this case?

A: The SPP line loss charges included in this case are the actual 12 months ending November 2011 net line loss charges from SPP. This adjustment is shown in Schedule BLC-6.

Q: What are SPP's RNU (revenue neutrality uplift) charges?

A: When SPP financially settles the EIS market, the total revenues collected by SPP do not always match the total required disbursements. This imbalance in revenues and payments is distributed among the market participants as either a debit (if SPP is short of funds to pay EIS market participants) or a credit (if SPP has collected more from EIS market participants than is needed to pay market participants). These debits and credits make up the RNU charges.

Q: Why is it appropriate that KCP&L adjust the off-system sales margins for SPP's RNU charges?

A: As a participant in the SPP EIS market, KCP&L is exposed to RNU charges. KCP&L books RNU revenue as off-system sales. This sales revenue is not included in the model used by Company witness Michael M. Schnitzer for determining off-system sales margins. KCP&L books RNU charges as a purchased power expense. KCP&L's

modeled purchased power expense does not include this expense. As such, the net SPP RNU charges have been included as an adjustment to Mr. Schnitzer's off-system sales margin. Absent this adjustment, RNU related debits and credits would not otherwise be reflected in the Company's retail cost of service.

Q: What is the basis of the net SPP RNU charge amount included in this case?

A: The RNU charges included in this case are the actual 12 months ending November 2011 net SPP RNU charges. This adjustment is show in Schedule BLC-7.

Q: In KCP&L's last rate case, did the Commission approve the requested adjustments for SPP line losses and RNU charges?

A: Yes, the Commission approved these adjustments which I recommended in its Report and Order of April 12, 2011 in the Company's last general rate case, Case No. ER-2010-0355.

Q: Please summarize the off-system sales margins reflected in cost of service in this rate proceeding.

A: Off-system sales margins reflect the combination of Company witness Michael M. Schnitzer's 40^{th} percentile computation, as well as adjustments to that computation for Purchases for Resale, SPP line loss charges and RNU charges. The resulting off-system sales margin is included in the derivation of adjustment R-35, which is reflected in Schedule JPW-4 sponsored by Company witness John P. Weisensee in his Direct Testimony.

IV. ELECTRIC UTILITY FUEL AND PURCHASED POWER COST RECOVERY MECHANISM

Q: In regard to KCP&L's request for approval of an IEC, which portions of the Electric Utility Fuel and Purchased Power Cost Recovery Mechanism filing requirements are you addressing in your testimony?

A: I will address all or portions of 4 CSR 240-3.161(2)(O), (P), (Q) and (R). Requirement (O) addresses the projected generation and Demand Side Management dispatch over the next four years, requirement (P) addresses procedures for heat rate tests, requirement (Q) addresses the long-term resource planning process, and requirement (R) addresses forecasted environmental investments.

Q: Please describe your support for compliance with 4 CSR 240-3.161(2)(O)?

A: 4 CSR-3.161(2)(O) requires the Company to provide:

> The supply-side and demand-side resources that the electric utility expects to use to meet its loads in the next four (4) true up years, the expected dispatch of those resources, the reasons why these resources are appropriate for dispatch and the heat rates and fuel types for each supply-side resource; in submitting this information, it is recognized that supply- and demand-side resources and dispatch may change during the next four (4) true-up years based upon changing circumstances and parties will have the opportunity to comment on this information after it is filed by the electric utility; ....

The expected resource dispatch levels for the next four true up years and fuel types can be found in Schedule BLC-8 (HC). Heat rate test results are provided in Schedule BLC-12 (HC).

Q: Why are these resources appropriate for dispatch?

A: The resources shown in Schedule BLC-8 (HC) include those resources owned or under contract. These resources are dispatched on an economic basis. This means the lowest cost resources are generally dispatched to serve KCP&L's native load obligations before higher cost resources. Any remaining generating capability above that needed to meet native load obligations is made available for sale in the wholesale market. The expected resource dispatch levels shown in Schedule BLC-8 (HC) are based on an economic dispatch.

Q: Has KCP&L developed a heat rate test procedure and proposed testing schedule for its generating units required per 4 CSR 240-3.161(2)(P)?

A: Yes. The general procedure for non-nuclear facilities is provided in Schedule BLC-10. A proposed schedule for performing heat rate testing is provided in Schedule BLC-9. For Wolf Creek, a monthly heat rate calculation is performed. The thermal gross generation is divided by the electrical gross generation and multiplied by 3,431 to derive the plant's heat rate in terms of Btu/kWh. The historical results of this heat rate calculation are provided in Schedule BLC-11 (HC).

Q: Please provide your support for 4 CSR-3.161(2)(Q).

A: 4 CSR-3.161(2)(Q) requires the Company to provide:

> Information that shows that the electric utility has in place a long-term resource planning process, important objectives of which are to minimize overall delivered energy costs and provide reliable service; ....

KCP&L has a long-term resource planning process. The electric utility resource plan produced by the process is also known as an integrated resource plan ("IRP"). An objective of this planning process is to identify the least cost and preferred resource plans while maintaining adequate capacity reserves for reliability.

Q: When was KCP&L's last IRP prepared?

A: KCP&L prepared and filed its latest IRP report in August 2008 under Case No. EE-2008-0034.

Q: When will the next KCP&L IRP be prepared?

A: Under the current IRP rule, the next KCP&L IRP is to be filed in April 2012.

Q: Please provide your support for 4 CSR 3.161(2)(R).

A: 4 CSR 3.161(2)(R) states:

> If emission allowance costs or sales margins are included in the RAM request and not in the electric utility's environmental cost recovery surcharge, a complete explanation of forecasted environmental investments and allowance purchase and sales; ....

KCP&L is currently making a significant investment in environmental controls at the LaCygne Generating Station near LaCygne, Kansas. These investments include:

LaCygne 1

- Flue Gas Desulfurization (scrubber) replacement primarily for SO_2 control.
- Pulse Jet Fabric Filter (baghouse) addition for particulate matter control.
- Activated carbon injection for mercury control.

LaCygne 2

- Selective Catalytic Reduction (SCR) system addition for NO_x control.
- Flue Gas Desulfurization (scrubber) addition primarily for SO_2 control.
- Pulse Jet Fabric Filter (baghouse) addition for particulate matter control.
- Activated carbon injection for mercury control.

This equipment is required to meet the Kansas State Implementation Plan for addressing the Clean Air Visibility Rule, also known as BART (best available retrofit technology). The current estimated cost of these environmental investments is $1.23 billion. The final cost will be split 50/50 between KCP&L and Westar. The forecasted emission allowance purchases required by 4 SCR 3.161(2)(R) can be found in the Direct Testimony of Company witness Wm. Edward Blunk.

In addition to these environmental investments in LaCygne, KCP&L is in the process of adding environmental controls at the Montrose Generating Station near Clinton, Missouri in anticipated compliance with the EPA's Cross-State Air Pollution Rule. For Montrose Units 2 and 3 these controls would include:

- Separated over fire air system for NO_x control;
- Burner modifications for NO_x control; and
- New burner management system.

The estimated installed cost of these controls is approximately **[redacted]**.

In order to comply with EPA's recently issued Mercury and Air Toxics Standards ("MATS"), KCP&L may need to install baghouses and activated carbon injection ("ACI") at Montrose. Adding a baghouse to Units 2 & 3 would cost approximately **[redacted]** and adding ACI to all the Montrose units is estimated to cost **[redacted]**. MATS compliance will also likely require ACI at Hawthorn Unit 5. The estimated cost for these controls is **[redacted]**.

Since KCP&L's MATS compliance strategy is still under evaluation, the estimated cost of compliance may change.

Q: **Does that conclude your testimony?**

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light	)	
Company's Request for Authority to Implement	)	Case No. ER-2012-0174
A General Rate Increase for Electric Service	)	

AFFIDAVIT OF BURTON L. CRAWFORD

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Burton L. Crawford, being first duly sworn on his oath, states:

1. My name is Burton L. Crawford. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Energy Resource Management.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of twenty (20) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Burton L. Crawford

Subscribed and sworn before me this 27th day of February, 2012.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2015

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2015
Commission Number: 11391200

SCHEDULE BLC-1

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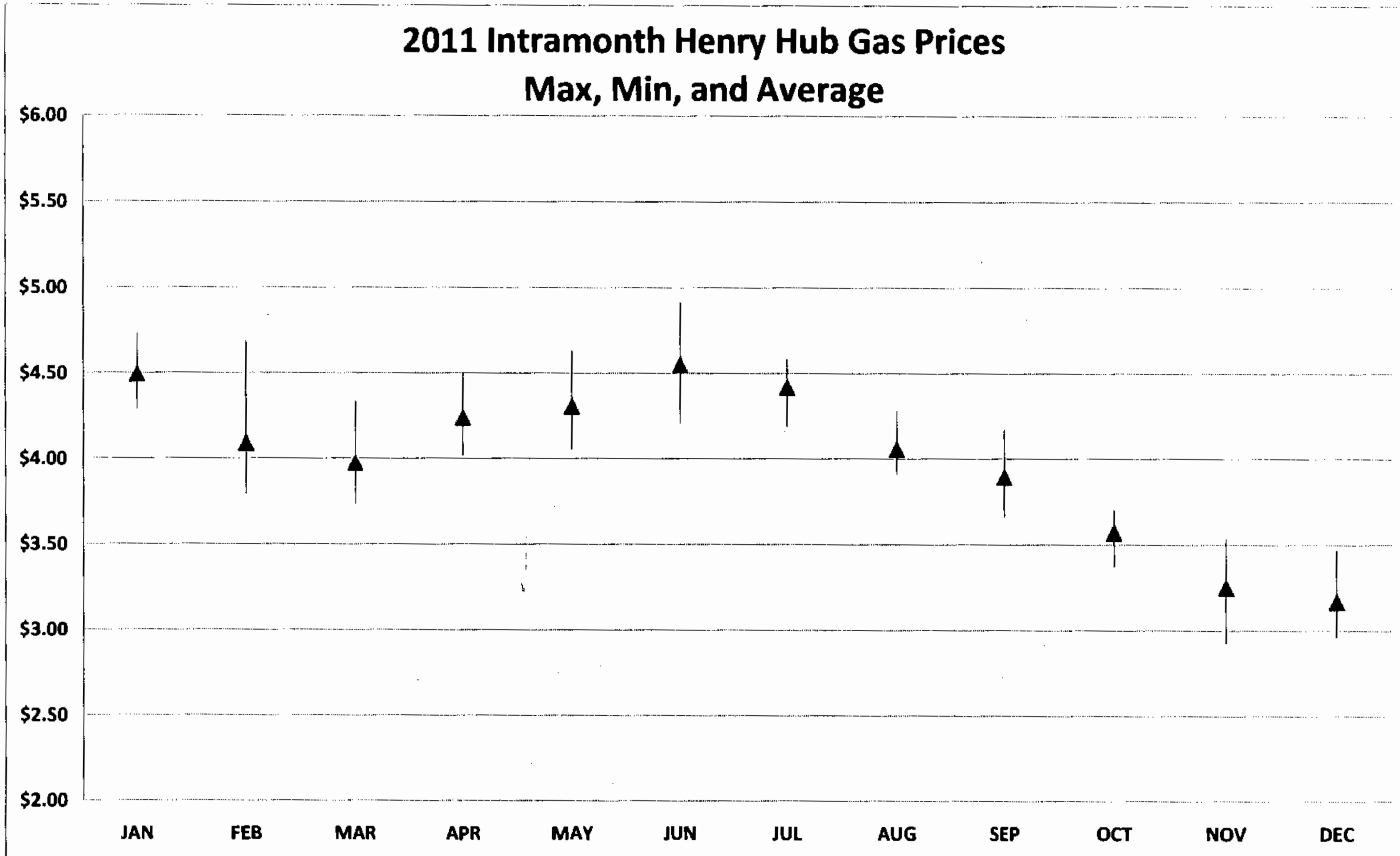

Schedule BLC-2

SCHEDULES BLC-3 thru BLC-4

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Kansas City Power & Light

Adjustment for Purchases For Resale
Schedule BLC-5
Filing Case - 12 ME 10/31/2011

Year	Month	Total	SPP Sale from Bilateral Purchase	Bilateral Sale from Bilateral Purchase	SPP Sale from SPP Purchase	Bilateral Sale from SPP Purchase
	Transaction Type		(Type 1)	(Type 2)	(Type 3)	(Type 4)
2010	November	486,489	45,765	9,426	(3,094)	434,392
2010	December	272,358	10,489	(5,598)	(14,130)	281,597
2011	January	345,756	(120,074)	(88,706)	(4,461)	558,998
2011	February	124,133	(3,406)	(338)	(14,713)	142,590
2011	March	61,257	(129,230)	(56,720)	(16,682)	263,889
2011	April	132,497	(92,732)	(37,094)	(3,740)	266,063
2011	May	121,198	(125,202)	(20,795)	(9,670)	276,866
2011	June	(270,164)	(226,876)	(195,421)	14,101	138,032
2011	July	224,949	154,472	(7,975)	23,508	54,944
2011	August	247,689	73,904	131,312	(537)	43,010
2011	September	(86,343)	(72,084)	(76,567)	(9,974)	72,282
2011	October	84,671	12,646	(9,341)	(46,031)	127,397
	Total	1,744,491	(472,330)	(357,815)	(85,425)	2,660,061
		Gain	Loss	Loss	Loss	Gain

Kansas City Power & Light

Adjustment for SPP Line Loss Charges & Revenues
Schedule BLC-6
Filing Case - 12 ME 11/30/2011

KCPL SPP Loss Related Charges and Revenue

	SPP Loss Charges	SPP Loss Revenues	Net Loss Revenue
December 2010	130,260	43,247	(87,013)
January 2011	173,887	54,686	(119,201)
February 2011	104,352	36,632	(67,721)
March 2011	54,583	25,131	(29,453)
April 2011	65,756	28,472	(37,284)
May 2011	128,094	36,307	(91,787)
June 2011	90,844	40,355	(50,489)
July 2011	68,586	47,152	(21,434)
August 2011	66,907	43,375	(23,532)
September 2011	140,819	33,176	(107,643)
October 2011	188,475	37,486	(150,989)
November 2011	150,229	37,328	(112,901)
Total	1,362,794	463,348	(899,447)

Kansas City Power & Light

Adjustment for SPP Revenue Neutrality Uplift
Schedule BLC-7
Filing Case - 12 ME 11/30/2011

		Net Charges
December	2010	(169,932)
January	2011	(96,809)
February	2011	(171,804)
March	2011	(137,405)
April	2011	(67,013)
May	2011	(81,688)
June	2011	(118,404)
July	2011	(188,790)
August	2011	(159,760)
September	2011	(59,735)
October	2011	(8,783)
November	2011	69,266
Total		$ (1,190,857)

SCHEDULE BLC-8

THIS DOCUMENT CONTAINS HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

KCPL IEC Heat Rate Testing Schedule

Unit	Baseline Test complete by	2010 Test completed	2011 Test completed	2012 Testing Schedule	Comments
Iatan 1	7/16/2009	7/16/2009	12/6/2011	-	
Iatan 2	12/31/2010	12/3/2010	-	12/3/2012	
LaCygne 1	3/31/2011	-	3/30/2011	-	
LaCygne 2	12/31/2010	6/18/2010	-	6/18/2012	
Hawthorn 5	12/31/2010	6/24/2010	-	6/24/2012	
Hawthorn 6/9	12/31/2011	8/2/2010	-	8/2/2012	
Hawthorn 7	12/31/2010	9/10/2010	-	9/10/2012	
Hawthorn 8	12/31/2010	9/10/2010	-	9/10/2012	
Montrose 1	12/31/2010	8/3/2010	-	8/3/2012	
Montrose 2	12/31/2010	6/25/2010	-	6/25/2012	
Montrose 3	12/31/2010	7/14/2010	-	7/14/2012	
Northeast 11	12/31/2010	10/15/2010	-	10/15/2012	
Northeast 12	12/31/2010	10/12/2010	-	10/12/2012	
Northeast 13	12/31/2010	10/15/2010	-	10/15/2012	
Northeast 14	12/31/2010	10/15/2010	-	10/15/2012	
Northeast 15	12/31/2010	10/15/2010	-	10/15/2012	
Northeast 16	12/31/2010	10/18/2010	-	10/18/2012	
Northeast 17	12/31/2010	10/14/2010	-	10/14/2012	
Northeast 18	12/31/2010	10/14/2010	-	10/14/2012	
West Gardner 1	12/31/2010	10/5/2010	-	10/5/2012	
West Gardner 2	12/31/2010	10/5/2010	-	10/5/2012	
West Gardner 3	12/31/2010	10/5/2010	-	10/5/2012	
West Gardner 4	12/31/2010	10/5/2010	-	10/5/2012	
Osawatomie 1	12/31/2010	9/29/2010	-	9/29/2012	

GENERATING UNIT HEAT RATE TESTING PROCEDURE

ETP- 002

Revision: 0.01	Date: 09/13/2011
Submitted: /s/ Nick McCarty	Operations Programs Specialist
Reviewed: /s/ Tony Russaw	Operations Programs Superintendent
Reviewed: /s/ Dave Daraban	Manager, Central Plant Operations
Reviewed: /s/ Kevin Noblet	Director, Supply Services
Plant Manager Review	
Hawthorn: /s/ Darrel Hensley	Iatan: /s/ Tom Mackin
La Cygne: /s/ Ron Sheffield	Lake Road: /s/ Mark Howell
Montrose: /s/ Greg Lee	Sibley: /s/ Dan Rembold
Approved: /s/ Marvin Rollison	Vice President, Renewables
Approved: /s/ Scott Heidtbrink	Senior Vice President, Supply

KCP&L

Revision List

Rev Number	Date	Comments
0	04/26/2010	Issue for use.
0.01	9/13/2011	In section 7.6 added the word "net" in front of heat rate calculation. **/l/ Tom Mackin**

KCP&L

1. Purpose

1.1. To establish a standardized procedure for testing and reporting generating unit heat rates to facilitate an accurate means for evaluating generating unit performance. This test will be conducted in accordance with the requirements of Public Service Commission (PSC).

2. Scope

2.1. This procedure will address Heat Rate testing for generating facilities. It defines when Heat Rate Testing will be conducted and where the data is to be sent. Specific information and testing instructions will be handled at each individual generating facility.

3. References

3.1. Unit Capability Testing Procedure – ETP-001

3.2. Aquila PSC FAC ruling – section 4 CSR 240-3.161

3.3. Rules of the Department of Economic Development, Division 240 – Public Service Commission, Chapter 3 – Filing and Reporting Requirements, Section 4 CSR 240-3.161

4. Definitions

4.1. Heat Rate: A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

5. Responsibility

5.1. It will be the responsibility of the Station Performance Engineer, or the Operations Superintendent in their absence, to ensure that the Heat Rate Test is performed on the unit(s) in compliance with each individual plant testing instructions.

5.2. It will be the responsibility of the Performance Testing Coordinator in Central Engineering to coordinate Heat Rate Tests with the Power Control Center and the Generating Facility and then send the data to the Resource Planning Engineer in Energy Resource Management (ERM) to be dispersed as necessary.

5.3. It will be the responsibility of the Resource Planning Engineer in ERM to make the initial notification to the Station Performance Engineers and Central Engineering for Heat Rate tests that are due for the upcoming year.

6. Safety

6.1. No additional safety requirements beyond those in the KCP&L Safety Rules and Procedures.

7. Instructions

7.1. Instrument calibration shall be performed prior to the test as appropriate.

7.2. Determine appropriate heat rate testing conditions exist, this includes items such as ensuring the furnace and convection pass are relatively clean and clear of eyebrows, slag and fouling, each condenser section are clean and the boiler has no tube leaks.

7.3. Test duration requires a 30 minute settling period once the load requirement is met and steady state operation within 5% of the target load. The remainder of the test shall be 4 hours for coal units and 2 hours for Combustion Turbine (CT) and combined cycle units.

7.4. Fuel samples shall be collected for the settling period and once hourly during the test in accordance with fuel sampling protocol. Samples shall be tested for Btu content using the Central Laboratory. Fuel blend shall be noted.

7.5. For coal units, ash samples shall be collected and tested for Loss on Ignition (LOI) by the Central Laboratory according to the appropriate procedure.

7.6. Station Performance Engineers, or the Plant Operations Superintendent in their absence, shall review preliminary test data to ensure test validity. If data is acceptable, perform the net heat rate calculation using only the data for the testing period to determine the final net unit heat rate. This calculation will be performed by the station Performance Engineer or Central Engineering.

8. Documentation

8.1. In accordance with the Rules of the Department of Economic Development, Division 240 – Public Service Commission, Chapter 3 – Filing and Reporting Requirements, Section 4 CSR 240-3.161, Heat Rate Testing shall be conducted at least once every 2 years and will coincide with the required Accredited Capacity Testing.

8.2. All data collected from the test along with analysis/calculations shall be forwarded to the Resource Planning Engineer in Energy Resource Management (ERM) and the Performance Testing Coordinator in Central Engineering. These two groups will collectively develop a formalheat rate test report for each individual test that includes test data, analyses/calculations and an Executive Summary. The report will be forwarded to management staff at the appropriate facility for review and comments prior to further distribution.

8.3. Energy Resource Management (ERM) will forward the formal heat rate test report to KCP&L Regulatory Department and other departments as appropriate.

9. Recordkeeping

9.1. The Operations Programs Group will maintain this document. The original will be stored electronically by the Operations Programs Group and a copy will be available for use on the Operations Programs Website. A signed hard copy will be maintained by the Operations Programs Group. There will be no other hard copies produced or maintained. This procedure should be reviewed every five years for revision. It will be reviewed by the Operations Programs Group Superintendents and the Operations Programs Manager. It will be approved by the Vice President, Supply Division.

SCHEDULES BLC-11 thru BLC-12

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