Exhibit No.:	
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Witness:	Burton L. Crawford
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2014-0370
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2014-0370

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
October 2014

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

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

Case No. ER-2014-0370

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 "Company") as Director, Energy Resource Management.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L.

Q: What are your responsibilities?

A: My responsibilities include managing the Energy Resource Management ("ERM") department. Activities of ERM include integrated resource planning, wholesale energy purchase and sales evaluations, fuel budgeting, renewable energy standards compliance, 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 ("KCC") 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 sales revenues filed in the Direct Testimony of Company witness Ronald A. Klote. 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 a Fuel Adjustment Clause ("FAC"). I specifically address all or a portion of the requirements of 4 CSR 240-3.161(2)(O), (P), (Q) and (R).

In addition, this testimony supports the Company's decision to invest in the environmental retrofits necessary for continued operation of La Cygne Units 1 and 2. It includes a description of KCP&L's long-term generation planning process, a description of the alternative resource plans that were considered to meet KCP&L's load requirements, and a discussion of the analysis of those alternatives.

I. ENERGY PRICE FORECASTS

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

A: KCP&L utilizes the MIDAS^{TM} model, which is similar to other fundamental price forecasting models that are commonly used in the industry. MIDAS^{TM} 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 region of the Southwest Power Pool ("SPP").

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 January 2013 through June 2014 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 from January 2013 through June 2014. In addition to intra-month gas prices, hourly demand would influence our backcast versus the actual market.

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

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

II. FUEL, PURCHASED POWER AND OFF-SYSTEM SALES NORMALIZATION

Q: What method for normalizing the test year fuel cost, purchased power cost and off-system sales did you use in this case?

A: The proper method for normalizing the test year fuel, purchased power and off-system sales is to normalize and annualize the system peak and energy, wholesale market prices, the prices paid for fuel, generating system maintenance and forced outages, and available generating resources. After determining the appropriate normalized and annualized values, a production cost computer modeling tool is used to develop the appropriate generation and purchased power levels, and resulting fuel cost, purchased power cost and off-system sales revenues. KCP&L used the MIDAS™ model for its production cost model.

Q: Please describe the MIDAS™ 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 and make off-system sales when economic. 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 Albert R. Bass. This resulted in revised monthly peak demands and energy requirements, which were input into the MIDAS^{TM} 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 the city of Chanute, city of Eudora and the Kansas Municipal Energy Association (KMEA). The revenue for these transactions and the associated fuel expense is included in Schedule BLC-4 (HC).

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 occur every 18 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 the true-up date in this case.

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. Other renewable generation resources have been included in the modeling as purchased power agreements from resources that are operating and under contract (Spearville 3, Cimarron and CNPPID hydro). The generation levels and energy prices are based upon signed contracts and operating history.

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: What is the SPP Integrated Marketplace ("IM")?

A: The SPP IM is a new marketplace that is comprised of the day-ahead market, real-time balancing market, and congesting hedging markets, and allows SPP to decide which generators should operate one day ahead of time. By allowing SPP to monitor energy costs from multiple sources, the SPP IM is intended to improve grid reliability, regional balancing of supply and demand, and cost-effectiveness. The SPP IM replaced SPP's Energy Imbalance Service Market, which was in operation since 2007.

Q: How does the new SPP IM impact KCP&L's fuel and purchased power modeling?

A: Prior to the SPP IM, KCP&L generation was first dispatched to meet KCP&L native load obligations with any excess economic generation going to off-system sales. When wholesale market prices were such that it was economic to purchase power to meet a portion of KCP&L's native load obligations instead of using KCP&L generating resources, wholesale purchases were made.

Under the SPP IM, KCP&L now sells all energy generated to the SPP market and purchases all native load requirements from the SPP market. This significantly increases the amount of both wholesale sales and purchases.

Q: For the test period, what revenue and expense items, if any, were adjusted as a result of normalizing fuel cost, purchased power costs and off-system sales?

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. Finally, bulk power sales were adjusted to reflect the changes in the quantity of capacity and energy sold and the price of such sales. 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 RAK-4, attached to the Direct Testimony of Company witness Ronald A. Klote (adjustments CS-24 and 25).

III. ADJUSTMENTS TO THE NORMALIZED FUEL, PURCHASED POWER and WHOLESALE SALES RESULTS

Q: Does KCP&L propose any adjustments to the MIDAS™ model results?

A: Yes. Adjustments are made for ancillary services purchases and sales, SPP Revenue Neutrality Uplift ("RNU"), SPP to Midcontinent Independent System Operator ("MISO") market energy sales margins and Transmission Congestion Rights margins.

Q: What are ancillary services purchases and sales?

A: As a participant in the SPP IM, KCP&L is obligated to provide or procure certain ancillary services. These services include spinning, supplemental and regulating reserves. KCP&L purchases its SPP-specified ancillary service from the SPP-operated ancillary service market.

In addition, KCP&L has the opportunity to sell these ancillary services in the SPP-operated market.

Q: What amount of ancillary services purchases and sales has KCP&L included in this case?

A: The amount of ancillary service purchases and sales included in this case is based on the actual costs and revenues incurred by KCP&L since the SPP IM started. Because the market started March 1, 2014, less than one year of actual ancillary service purchases and sales information is available. Accordingly, actual data from March 1 through July 31, 2014 was adjusted to represent a full year of costs and revenues. These values will be updated to actual amounts for the most recent 12 months at true-up.

Q: What are SPP's RNU charges?

A: As a participant in the SPP IM, there are a number of miscellaneous charges and credits incurred in order for SPP to remain revenue neutral. These charges and credits include items such as rounding errors and inadvertent interchange costs or revenue, and make up the RNU charges. RNU is distributed among the market participants as either a debit (if SPP is short of funds to balance payments between participants) or a credit (if SPP has collected more than needed to balance payments between participants).

Q: Why is it appropriate that KCP&L include net RNU charges in its calculation of revenue requirements?

A: As a participant in the SPP IM, KCP&L is exposed to RNU charges and credits. These charges and credits are not included in the model used by the Company to calculate fuel and purchased power costs. As such, the net SPP RNU charges have been included as an adjustment to KCP&L's model results. Absent this adjustment, RNU-related charges 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 based on the actual five months ending July 2014 net SPP RNU charges, annualized to a 12-month period. This adjustment is shown in Schedule BLC-4 (HC). This RNU amount will be updated at the true-up in this case.

Q: What are SPP to MISO market energy sales margins?

A: KCP&L's energy traders monitor the difference between SPP and MISO real-time energy market prices. When these real-time energy market prices are such that energy can be purchased in SPP and then sold to MISO at a projected profit, purchase and sales transactions are made.

Q: Are these transactions always profitable?

A: No. There are a number of charges assessed by SPP and MISO on these transactions that are not known until sometime after the transaction is complete. These charges cover items such as RNU and ancillary services. As such, transactions that look to be profitable can become unprofitable after the fact.

Q: In total, have these transactions been profitable thus far?

A: Yes. The net profits from May 10, 2014 through August 28, 2014 have been annualized and can be found in Schedule BLC-4 (HC). This amount will be updated at the true-up in this case.

Q: What is Transmission Congestion Rights margin?

A: Under the SPP IM, there are additional charges for moving energy from generation to load when the transmission system becomes congested. As part of the SPP IM development, financial instruments were created to hedge these transmission congestion charges. These hedges are called Transmission Congestion Rights ("TCRs"). In theory, transmission customers such as KCP&L are allocated TCRs in sufficient quantity to hedge the actual transmission congestion charges incurred to serve their native load obligations. However, from March 1, 2014 when the SPP IM started through August 31, 2014, the revenue received from KCP&L's TCR portfolio has exceeded the estimated congestion costs. The estimated annualized net gain on KCP&L's TCR portfolio has been included as a credit to the retail cost of service. This annualized amount can be found in Schedule BLC-4 (HC). This amount will be updated at the true-up in this case.

IV. ELECTRIC UTILITY FUEL AND PURCHASED POWER COST RECOVERY MECHANISM

Q: In regard to KCP&L's request for approval of an FAC, 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 ("DSM") 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-5 (HC). Heat rate test results are provided in Schedule BLC-9 (HC).

Q: Why are these resources appropriate for dispatch?

A: The resources shown in Schedule BLC-5 (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 before higher cost resources. The expected resource dispatch levels shown in Schedule BLC-5 (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-7. A proposed schedule for performing heat rate testing is provided in Schedule BLC-6. 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-8 (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 update report in March 2014 in Case No. EO-2014-0256.

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 2015.

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 La Cygne Generating Station near La Cygne, Kansas. These investments include:

La Cygne 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.

La Cygne 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 CSR 3.161(2)(R) can be found in the Direct Testimony of Company witness Wm. Edward Blunk. Additional information on the need for these environmental investments can be found in the Direct Testimony of Company witness Paul M. Ling.

In order to comply with EPA's Mercury and Air Toxics Standards, KCP&L is in the process of installing activated carbon injection ("ACI") at Montrose Units 2 and 3 and precipitator improvements at an estimated cost of **[redacted]**. KCP&L is also installing ACI at Hawthorn Unit 5. The estimated cost for these controls is **[redacted]**.

V. LA CYGNE ENVIRONMENTAL RETOFIT INVESTMENTS

Q: Please describe KCP&L's planning process as it relates to the La Cygne environmental investments.

A: The process used in evaluating long-term resource plan alternatives was based on the electric IRP procedures required by Missouri Rule CSR 240 Chapter 22.

In the initial step, the Company reviews and screens a number of preliminary options for environmental compliance, system generation and customer demand response/energy efficiency programs ("DR/EE"). This step reduces the number of options to include in the evaluation of alternative resource plans. From these resource options, alternative resource plans are assembled. Each alternative resource plan is developed to meet the Company's reserve obligations and requirements of state(s) renewable portfolio standards ("RPS").

The plans developed in the previous step are then evaluated in MIDAS™ in order to calculate each plan's expected total revenue requirement over a number of years. These calculations are performed for each alternative resource plan under a variety of potential market futures (*i.e.*, scenarios) to determine the level of risk each alternative plan faces. These risks are defined by varying levels of critical uncertain factors such as natural gas prices, retail customer load growth, carbon dioxide ("CO_2") costs, etc. Sixty-four (64) scenarios were devised to gauge the risk associated with identified critical uncertain factors. A list of these scenarios is included in Schedule BLC-19.

The end result of this process is a series of alternative long-term resource plans, each with an expected 25-year net present value of revenue requirement ("NPVRR") that takes into account the risk associated with critical uncertain factors in the industry.

Q: Please detail the resource option screening process.

A: The resource screening process reduces the number of supply options to a manageable number. Each alternative is compared on an average cost of total operation. A limited number of alternatives are then passed forward for further consideration in the analysis.

Options that are more expensive to operate are barred from further consideration. This greatly improves the speed of the analyses that follow.

Q: Please describe the DR/EE screening process.

A: The Company retains the service of several consultants to identify DR/EE end-use measure potential. These measures are subjected to a benefit/cost screening analysis. Once screened, the load impact and costs of the remaining programs are treated as a single DR/EE program in the analysis.

Q: Describe the MIDAS™ model as it relates to resource planning.

A: MIDAS™ is a product of ABB-Ventyx and has been an industry standard production and financial cost model for over 20 years. The modeler inputs a resource expansion plan that can include different assumptions of environmental retrofits, plant retirements or system generation expansion. This expansion plan is added to the Company's existing portfolio of assets. Operation of the resulting asset portfolio is then simulated for 20+ years on an hourly basis to calculate the portfolio's production cost under given economic and market price assumptions. This production cost model is repeated for a large number of future scenarios of critical uncertain factors. The model outputs an annual revenue requirement using the results of the production cost model and the financial position of the Company to develop a complete view of Company costs. This annual revenue requirement is discounted to calculate the plan's NPVRR.

Q: How is the MIDAS™ model used in this analysis?

A: The MIDAS™ model takes each alternative expansion plan and calculates its financial performance under a large number of future scenarios. This set of future scenarios is referred to as the "Risk Tree" in MIDAS™. Each branch of the Risk Tree represents a different future scenario. Each scenario is made up of varying combination of uncertain market forecasts described below. The Risk Tree used in this analysis contains 64 different scenarios or branches. This Risk Tree is graphically represented in Schedule BLC-19.

Each expansion plan that is run through MIDAS™ has 64 separate NPVRR results. These separate results are probability weighted over the 64 scenarios to calculate an expected value of NPVRR for each expansion plan. The plan that has the lowest expected NPVRR therefore shows the greatest potential of cost effectiveness over a wide range of future risks. Furthermore, the results can be evaluated scenario-by-scenario to determine if there exist any future risks that will cause another plan to perform better than the plan with the lowest expected NPVRR.

Q: What sort of information is collected and used in the planning process?

A: The Company uses a wide range of information to conduct this analysis. Data is collected on potential resource options including supply resources (coal, natural gas, nuclear, renewable, etc.) and DR/EE measures. Along with these options, the Company collects information for environmental retrofit costs.

Additionally, the Company develops forecasts of critical uncertainties. These include, but are not limited to natural gas prices, CO_2 emission allowance prices, load growth rates, interest rates and costs to acquire capital, coal prices, construction costs, etc. These forecasts include a mid, high and low case for each critical driver.

Other information used in the analysis relate to current issues and events that may drive resource acquisition decisions such as the impact of state-based renewable standards or federal mandates.

Q: With regard to uncertainties, what were your major assumptions and their sources?

A: In 2010 when the analysis was undertaken to determine if additional environmental controls should be constructed at La Cygne, the major assumptions sourced from the KCP&L ERM Department included:

- All uncontrolled coal plants will be environmentally retrofitted (scrubbers, SCR, bag house) or retired/mothballed by 2016.
- State RPS for Missouri and Kansas will be met with constructed generation. The Company does not assume that it will rely on purchased renewable energy credits for long-term compliance.

Major assumptions sourced from the KCP&L Fuels Department:

- Natural Gas Prices. See Schedule BLC-10 (HC).
- CO_2 Allowance Prices. See Schedule BLC-11 (HC).

Support for these assumptions can be found in the Direct Testimony of Company witness Mr. Wm. Edward Blunk.

Major assumptions sourced from the KCP&L Load Forecasting Department:

- Annual Retail Load Growth – Energy. See Schedule BLC-12 (HC).
- Annual Retail Load Growth – Peak Demand. See Schedule BLC-13 (HC).

Please note that a complete discussion of the method of developing this load forecast is included in the Direct Testimony of Company witness Mr. Albert R. Bass, Jr. Also note that the load forecast starts in 2011 which was the first year of the La Cygne analysis period.

Major assumptions sourced from the KCP&L Energy Solutions Department:

- DR/EE Resources. See Schedules BLC-14 (HC) and BLC-15 (HC).

Major assumptions sourced from the KCP&L Corporate Finance Department:

- Financial Returns and Interest Rates. See Schedule BLC-16 (HC).

Q: What alternative plans were analyzed?

A: The analysis considered 14 different resource plans with four additional sensitivity plans. These plans are described in detail in Schedule BLC-22 (HC).

Q: In 2010 when the La Cygne analysis was undertaken, what were KCP&L's expected capacity and/or energy needs given the Company's then existing generation portfolio?

A: Capacity and Load Balance for KCP&L both with and without the La Cygne units are shown in Schedule BLC-20 (HC).

Q: Was capacity from La Cygne projected to be needed?

A: As shown in Schedule BLC-20 (HC), the capacity of La Cygne Units 1 and 2 was needed.

Q: Should KCP&L have invested in environmental controls at La Cygne or built new capacity?

A: In the case of La Cygne Units 1 and 2, KCP&L has shown that the capacity and energy from these units was projected to be needed. Based on the Company's resource plan analysis and the NPVRR results shown in Schedule BLC-21 (HC), retrofit of the existing La Cygne Units 1 and 2 was the least cost option to continue to supply the capacity and energy needs of our customers.

Q: What criteria should be employed to determine optimal retrofit configurations to meet regulatory requirements?

A: In general, the criteria to be employed are the minimization of NPVRR. Once the retrofit has been completed for La Cygne Units 1 and 2, the only KCP&L plants that generally do not meet best available retrofit technology are the three Montrose units. Based on current assumptions and analysis, it is least cost to continue to run these plants until significant environmental retrofits are required for continued operation. Although NPVRR is the primary basis for evaluation of resource alternatives, other factors are relevant to the decision making process. For instance, it is important to maintain a balanced portfolio of generation resources. KCP&L anticipates, of the two existing generation sites that have not yet been retrofitted namely Montrose Station and La Cygne Station, Montrose would be the first existing generation site to retire rather than be retrofit. Given this, it is important to retain operation of the La Cygne site to maintain a balanced portfolio of coal, gas, nuclear, and renewable generation. At the time the analysis was done, the least cost alternative to retrofitting existing units to meet BART was combined cycle ("CC") gas generation. Retiring La Cygne generating station and replacing it with CC generation, followed by retirement of Montrose station generation with CC replacement would result in a significant reliance on the relatively more volatile natural gas market. NPVRR is based on the long-term economics of resource alternatives. It does not reflect shorter-term variations in fuel cost that can impact customers immediately. (See Mr. Wm. Edward Blunk's Direct Testimony for further discussion of natural gas market volatility.)

Q: Do the environmental retrofit projects that are currently installed, under construction or planned represent the end of the upgrading process for their corresponding KCP&L generating units, or will the environmental retrofit projects, in turn, require additional improvements to these KCP&L units?

A: From an analysis perspective, KCP&L takes into account potential regulation changes to the extent that they are in place or proposed. To the extent they are probable, KCP&L models them. For example, KCP&L expects that cooling towers may need to be added to its coal plants. These costs were included in the analysis.

Q: For any planned but incomplete environmental upgrades, has analysis been performed on how the planned upgrades may impact the expected life of the plant at the completion of the upgrades? If so, what criteria for analysis were used?

A: The equipment to be installed at La Cygne Units 1 and 2 will not impact the useful life of the units. KCP&L has modeled continuation of La Cygne Units 1 and 2 throughout the planning period by incorporating normal maintenance activities and overlaid the cost of a long-range asset management plan.

Q: If replacement of a KCP&L plant is considered as an option, what criteria should be used to determine the size and type of the generation plant to be built?

A: The primary criteria employed are the same as that used to analyze the retrofits; that is, minimization of NPVRR. However, in some cases it may be prudent to select a resource plan that has a higher NPVRR if in doing so the risk associated with changes in critical uncertainties, environmental regulations, or other factors is mitigated.

Q: Why were other options to the La Cygne environmental investments rejected?

A: In this case, KCP&L has chosen to retrofit the La Cygne station with the equipment necessary to meet BART. All other options were rejected because they resulted in higher expected costs for retail customers over the next 20+ years. The expected value of NPVRR for each alternative plan is detailed in Schedule BLC-21 (HC). However, as I previously indicated, there are other reasons to reject replacement of La Cygne generation with new gas-fired generation. As for replacing La Cygne coal-fired generation with new coal-fired generation, the results of the NPVRR analysis places new coal-fired generation behind new gas-fired generation as an alternative to retrofitting La Cygne generation. In addition, new coal has all of the same risk related to future environmental regulations as retrofitting existing generation in addition to the uncertainty surrounding the ability to obtain air and other permits for new coal generation.

Q: What are the results of the analysis the Company prepared for evaluation of the La Cygne environmental retrofit decision?

A: The results of the planning process indicate that the La Cygne retrofits are part of the low cost plan in about 73% of the 64 scenarios analyzed. The scenarios where the retrofits were not selected generally include both the low gas price scenarios and the high CO_2 price scenarios.

Q: What was your recommendation concerning La Cygne at the time this analysis was completed?

A: La Cygne must meet BART requirements by June 1, 2015 or be retired/mothballed. The recommendation was to move forward with the retrofit of La Cygne Unit 1 and La Cygne Unit 2. This recommendation was supported by the results of the resource planning process conducted in 2010/11 which indicates that the retrofit of La Cygne Unit 1 and La Cygne Unit 2 was the appropriate least cost option. The La Cygne Unit 1 retrofit is consistent with the plan presented as part of the Settlement Agreement in Case No. EO-2005-0329 in which the Commission found it to be in the public interest at that time.

Q: In the intervening time since the Commission's finding in Case No. EO-2005-0329 have the circumstances concerning La Cygne Unit 1 changed in a way that would make the underlying rationale for finding the project to be in the public interest no longer applicable?

A: No, they have not. KCP&L has re-evaluated the decision in each of its IRP filings since 2010. As demonstrated by each analysis, the La Cygne 1 and 2 retrofits result in minimizing expected NPVRR.

Q: Has any state commission with jurisdiction over KCP&L retail electric service expressed an opinion on the merits of the decision to make the environmental investments in La Cygne?

A: Yes. In 2011, KCP&L sought pre-approval of the La Cygne environmental investments from the KCC in Docket No. 11-KCPE-581-PRE. Kansas law allows a utility to obtain "pre-approval" for such investments under K.S.A. 2010 Supp. 66-1239.

Q: What were the results of this pre-approval case?

A: In its Order granting KCP&L's petition for predetermination, the KCC made the following ruling:

> (1)The Commission finds the plan selected by KCP&L to retrofit La Cygne Units 1 and 2, as set forth in the La Cygne Project identified in this

proceeding and reflected in KCP&L Exhibit 5, is reasonable, reliable and efficient under K.S.A. 2010 Supp. 66-1239(c)(3)[1]

Q: Do you have any schedules which support your testimony?

A: Yes, I have included the following schedules which support the evaluation as part of my testimony:

- Schedule BLC-10 (HC) reflects 20-year assumptions for gas prices.
- Schedule BLC-11 (HC) reflects 20-year assumptions for CO_2 emission allowance costs.
- Schedule BLC-12 (HC) reflects the 20-year KCP&L energy forecasts.
- Schedule BLC-13 (HC) reflects the 20-year KCP&L gross peak load forecasts.
- Schedule BLC-14 (HC) reflects 20-year assumptions for annual DSM megawatts for the base scenarios.
- Schedule BLC-15 (HC) reflects 20-year assumptions for annual DSM megawatts for the sensitivity scenarios.
- Schedule BLC-16 (HC) reflects financial assumptions for debt ratio, debt rate and return on equity for various levels of future uncertainty.
- Schedule BLC-17 (HC) reflects utility nominal cost rankings for 54 different technologies.
- Schedule BLC-18 reflects details of the Company's existing generation resources.
- Schedule BLC-19 details the 64 scenarios of the analysis Risk Tree.

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[1] *Order Granting KCP&L Petition for Predetermination of Rate-Making Principles and Treatment*, Docket No. 11-KCPE-581-PRE, pp. 2-3 (Aug. 19, 2011).

- Schedule BLC-20 (HC) details the capacity and load balance of KCP&L with its existing fleet and under the assumption that the La Cygne station is removed from KCP&L's generation mix.
- Schedule BLC-21 (HC) details the results of the analysis and list the expected NPVRR of each alternative.
- Schedule BLC-22 (HC) details the 14 alternative expansion plans and the four sensitivity plans used in the analysis.

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 A General Rate Increase for Electric Service	)))	Case No. ER-2014-0370

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-seven (27) 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 30th day of October, 2014.

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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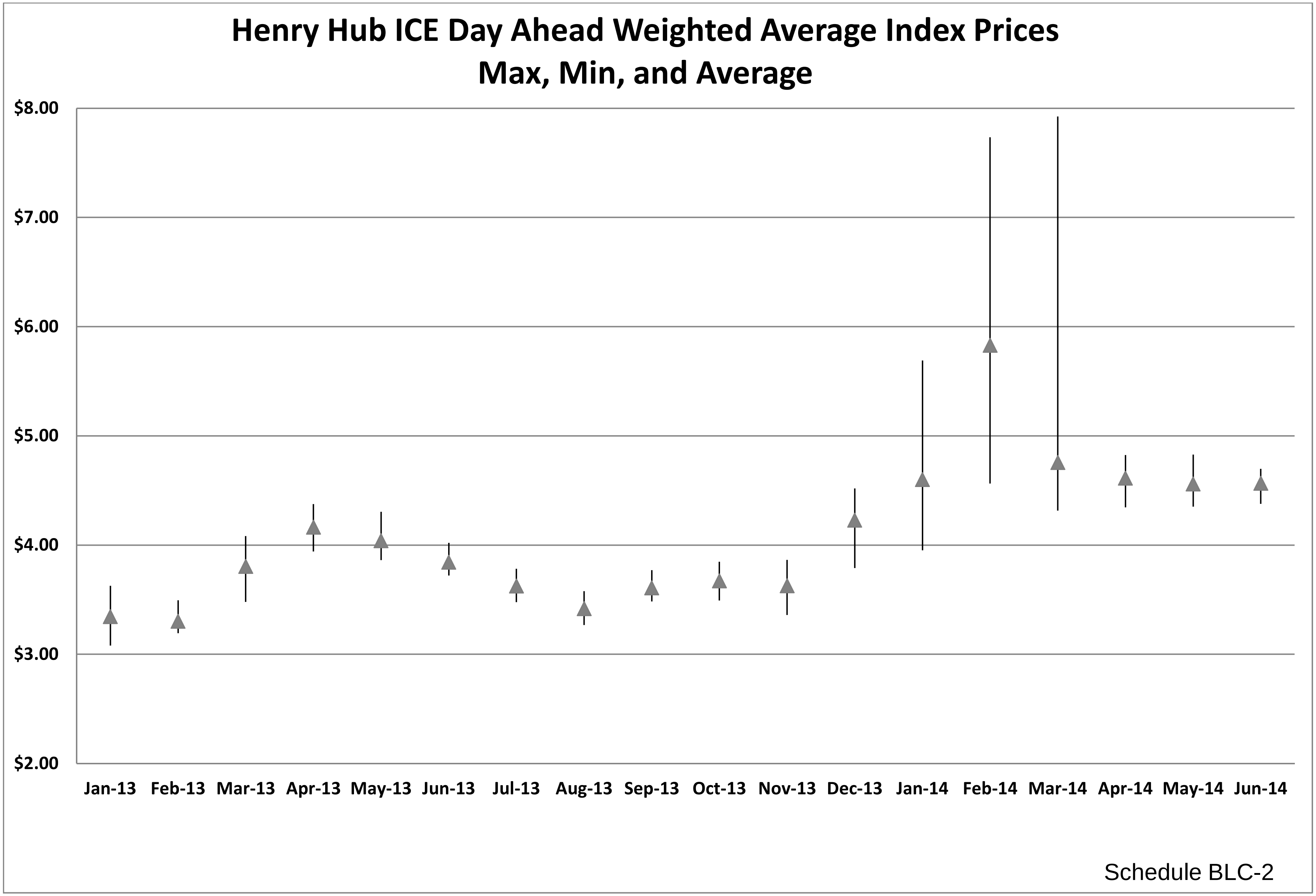
Henry Hub ICE Day Ahead Weighted Average Index Prices
Max, Min, and Average
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
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Nov-13
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Jun-14
Schedule BLC-2

SCHEDULES BLC-3 through BLC-5

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Heat Rate Testing Plan

Unit	Heat Rate due by
Hawthorn 5	8/23/14
Hawthorn 6-9	8/15/14
Hawthorn 7	8/30/14
Hawthorn 8	8/30/14
Iatan 1	10/3/15
Iatan 2	6/20/14
LaCygne 1	6/30/15
LaCygne 2	6/21/14
Montrose 1	8/3/14
Montrose 2	7/31/14
Montrose 3	7/26/14
Northeast 11	7/18/15
Northeast 12	7/18/15
Northeast 13	8/27/15
Northeast 14	7/18/15
Northeast 15	7/17/15
Northeast 16	7/17/15
Northeast 17	7/17/15
Northeast 18	7/17/15
Osawatomie	8/29/14
West Gardner 1	7/18/14
West Gardner 2	5/15/14
West Gardner 3	5/15/14
West Gardner 4	8/23/14

Generating Unit Heat Rate Testing Procedure

ETP- 002

Revision: 1	Date: 04/01/2013
Submitted: /s/ Nick McCarty	Operations Programs Specialist
Reviewed: /s/ Doug Luther	Operations Programs Superintendent
Plant Manager Review	
Hawthorn: /s/ Don Scardino	Iatan: /s/ Tom Mackin
La Cygne: /s/ Ron Sheffield	Lake Road: /s/ Mark Howell
Montrose: /s/ Greg Lee	Sibley: /s/ Dan Rembold
CTs: /s/ Stan Lister	
Approved: /s/ Darrel Hensley **Senior Director, Generation**	Approved: /s/ Kevin Noblet **Vice President, Generation**

Revision List

Rev Number	Date	Comments
0	04/26/2010	Issue for use.
0.01	09/13/2011	In section 7.6 added the word "net" in front of heat rate calculation. **/i/ Tom Mackin**
1	04/01/2013	Section 8.1 removed the wording "and will coincide with the required Accredited Capacity Testing.

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.

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 formal heat 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.

8.4. 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.

9. Attachments

9.1. None.

SCHEDULES BLC-8 through BLC-17

THESE DOCUMENTS CONTAIN HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

Location	OEM	Accredited total plant	Fuel	Environmental Equipment	Commissioned
Hawthorn 5	GE/B&W	564 MW	Coal	SCR, Scrubber, Baghouse, LNB, OFA	1969 (2001)
Iatan 1: 70%KCPL/18%GMO/12%EDE	GE/B&W	713 MW	Coal	SCR, Scrubber, Baghouse, LNB, OFA, Mercury	1980
Iatan 2: 54.71%KCPL/18%GMO/11.76%MJMUEC3.53%KEPCO	Toshiba/Alstom	881 MW	Coal	SCR, Scrubber, Baghouse, LNB, OFA Mercury	2010
LaCygne 1: 50%KCPL/50%Westar	Westinghouse/B&W	734 MW	Coal	SCR, Scrubber, OFA	1973
LaCygne 2: 50%KCPL/50%Westar	GE/B&W	682 MW	Coal	Precipitator	1977
Montrose 1	GE/CE	170 MW	Coal	Precipitator,	1958
Montrose 2	GE/CE	164 MW	Coal	Precipitator	1960
Montrose 3	Westinghouse/CE	176 MW	Coal	Precipitator	1964
Hawthorn 6/9 CC	Siemens V84.3A1 – W	227 MW	Gas		1997/2000
Hawthorn 7 & 8	GE Frame 7EA	157 MW	Gas		1999
Osawatomie	GE Frame 7EA	77 MW	Gas		2003
Northeast	GE Frame 7B (8)	373 MW	Oil		1972 - 1977
West Gardner	GE Frame 7EA (4)	311 MW	Gas		2002
Wolf Creek: 47%KCPL/47%Westar/6% KEPCo	Westinghouse	1164 MW	Nuclear		1985
Spearville 1	GE Wind Turbines	100.5 MW Nameplate	Wind		2006
Spearville 2	GE Wind Turbines	48 MW Nameplate	Wind		2010
Cimarron II	Siemens Wind Turbines	131.1 MW Nameplate	Wind		2012
Spearville 3	GE Wind Turbines	100.8 MW Nameplate	Wind		2012

Scenario/Endpoint Numbering

Schedule BLC - 19

Scenario	Load Growth	Construction Costs	Interest/ Finances	CO2	Natural Gas	Coal	Conditional Probability	Cummulative Probability	Market Price Curve
1	High	High	High	High	High	High	0.081%	0.081%	HHH
2	High	High	Mid	Mid	Mid	Mid	1.316%	1.397%	BBB
3	High	Mid	Mid	High	Mid	Mid	1.316%	2.712%	HBB
4	High	Mid	Mid	Mid	High	Mid	1.316%	4.028%	BHB
5	High	Mid	Mid	Mid	Mid	High	1.316%	5.344%	BBH
6	High	Mid	High	Mid	Mid	Mid	1.296%	6.640%	BBB
7	High	Mid	Mid	Mid	Mid	Mid	2.631%	9.271%	BBB
8	High	Mid	Mid	Mid	Mid	Low	1.316%	10.587%	BBL
9	High	Mid	Mid	Mid	Low	Mid	1.316%	11.902%	BLB
10	High	Mid	Mid	Low	Mid	Mid	1.316%	13.218%	LBB
11	High	Low	Mid	Mid	Mid	Mid	1.316%	14.534%	BBB
12	Mid	High	Mid	High	Mid	Mid	1.316%	15.849%	HBB
13	Mid	High	Mid	Mid	High	Mid	1.316%	17.165%	BHB
14	Mid	High	Mid	Mid	Mid	High	1.316%	18.481%	BBH
15	Mid	High	High	Mid	Mid	Mid	1.296%	19.777%	BBB
16	Mid	High	Mid	Mid	Mid	Mid	2.631%	22.408%	BBB
17	Mid	High	Mid	Mid	Mid	Low	1.316%	23.724%	BBL
18	Mid	High	Mid	Mid	Low	Mid	1.316%	25.039%	BLB
19	Mid	High	Mid	Low	Mid	Mid	1.316%	26.355%	LBB
20	Mid	Mid	Mid	High	High	Mid	1.316%	27.671%	HHB
21	Mid	Mid	Mid	High	Mid	High	1.316%	28.986%	HBH
22	Mid	Mid	High	High	Mid	Mid	1.296%	30.282%	HBB
23	Mid	Mid	Mid	High	Mid	Mid	2.631%	32.914%	HBB
24	Mid	Mid	Mid	High	Mid	Low	1.316%	34.229%	HBL
25	Mid	Mid	Mid	High	Low	Mid	1.316%	35.545%	HLB
26	Mid	Mid	Mid	Mid	High	High	1.316%	36.861%	BHH
27	Mid	Mid	High	Mid	High	Mid	1.296%	38.157%	BHB
28	Mid	Mid	Mid	Mid	High	Mid	2.631%	40.788%	BHB
29	Mid	Mid	Mid	Mid	High	Low	1.316%	42.104%	BHL
30	Mid	Mid	High	Mid	Mid	High	1.296%	43.400%	BBH
31	Mid	Mid	Mid	Mid	Mid	High	2.631%	46.031%	BBH
32	Mid	Mid	High	Mid	Mid	Mid	2.592%	48.623%	BBB
33	Mid	Mid	Mid	Mid	Mid	Mid	5.263%	53.886%	BBB
34	Mid	Mid	High	Mid	Mid	Low	1.296%	55.182%	BBL
35	Mid	Mid	Mid	Mid	Mid	Low	2.631%	57.813%	BBL
36	Mid	Mid	Mid	Mid	Low	High	1.316%	59.129%	BLH
37	Mid	Mid	High	Mid	Low	Mid	1.296%	60.425%	BLB
38	Mid	Mid	Mid	Mid	Low	Mid	2.631%	63.056%	BLB
39	Mid	Mid	Mid	Mid	Low	Low	1.316%	64.372%	BLL
40	Mid	Mid	Mid	Low	High	Mid	1.316%	65.687%	LHB
41	Mid	Mid	Mid	Low	Mid	High	1.316%	67.003%	LBH
42	Mid	Mid	High	Low	Mid	Mid	1.296%	68.299%	LBB
43	Mid	Mid	Mid	Low	Mid	Mid	2.631%	70.930%	LBB
44	Mid	Mid	Mid	Low	Mid	Low	1.316%	72.246%	LBL
45	Mid	Mid	Mid	Low	Low	Mid	1.316%	73.562%	LLB
46	Mid	Low	Mid	High	Mid	Mid	1.316%	74.877%	HBB
47	Mid	Low	Mid	Mid	High	Mid	1.316%	76.193%	BHB
48	Mid	Low	Mid	Mid	Mid	High	1.316%	77.509%	BBH
49	Mid	Low	High	Mid	Mid	Mid	1.296%	78.805%	BBB
50	Mid	Low	Mid	Mid	Mid	Mid	2.631%	81.436%	BBB
51	Mid	Low	Mid	Mid	Mid	Low	1.316%	82.752%	BBL
52	Mid	Low	Mid	Mid	Low	Mid	1.316%	84.067%	BLB
53	Mid	Low	Mid	Low	Mid	Mid	1.316%	85.383%	LBB
54	Low	High	Mid	Mid	Mid	Mid	1.316%	86.699%	BBB
55	Low	Mid	Mid	High	Mid	Mid	1.316%	88.014%	HBB
56	Low	Mid	Mid	Mid	High	Mid	1.316%	89.330%	BHB
57	Low	Mid	Mid	Mid	Mid	High	1.316%	90.646%	BBH
58	Low	Mid	High	Mid	Mid	Mid	1.296%	91.942%	BBB
59	Low	Mid	Mid	Mid	Mid	Mid	2.631%	94.573%	BBB
60	Low	Mid	Mid	Mid	Mid	Low	1.316%	95.889%	BBL
61	Low	Mid	Mid	Mid	Low	Mid	1.316%	97.204%	BLB
62	Low	Mid	Mid	Low	Mid	Mid	1.316%	98.520%	LBB
63	Low	Low	Mid	Mid	Mid	Mid	1.316%	99.836%	BBB
64	Low	Low	Mid	Low	Low	Low	0.164%	100.000%	LLL

SCHEDULES BLC-20 through BLC-22

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