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:	KCP&L Greater Missouri Operations Company
Case No.:	ER-2012-0175
Date Testimony Prepared:	February 27, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2012-0175

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KCP&L GREATER MISSOURI OPERATIONS 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-2012-0175

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") as Director, Energy Resource Management.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L Greater Missouri Operations Company ("GMO" or the "Company") for the territories served by St. Joseph Light & Power ("L&P") and Missouri Public Service ("MPS").

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 GMO's recent 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, off-system sales filed in the cost of service and to support the inclusion of transmission service costs for the Crossroads plant in the cost of service. In addition, I will provide information regarding the requirements necessary to support the Electric Utility Fuel and Purchased Power Cost Recovery Mechanism, in connection with GMO's request to continue its Fuel Adjustment Clause ("FAC"). I specifically address all or a portion of the requirements of 4 CSR 240-3.161(2)(P), (Q), (R) and (S).

I. ENERGY PRICE FORECASTS

Q: Could you describe how GMO forecasts electricity prices?

A: GMO 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, 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 cost 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 GMO'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 Southwest Power Pool ("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 your 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 GMO'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 GMO 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 market prices produced by the MIDAS model used in this case?

A: As more fully described in the next section of my testimony, the model's market prices are used to normalize purchased power and fuel expenses.

II. FUEL, PURCHASED POWER AND OFF-SYSTEM SALES 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. GMO 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 model 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: GMO'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 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 sale to the Western Area Power Administration has been added to the native load to arrive at the total system requirements. The revenue from this sale and the related costs to serve this load are 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. 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 weeks that a unit would be scheduled out for maintenance over the maintenance cycle and averaged this amount by the number of years in the maintenance cycle. These normalized maintenance outages 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 outage assumptions that were 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. Long-term purchase power contract levels reflect the capacity levels that are committed effective August 31, 2012.

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, the purchased power levels and the costs of each. The adjustments are reflected in Schedule JPW-4 L&P and Schedule JPW-4 MPS, attached to the Direct Testimony of Company witness John P. Weisensee.

Q: What method did you use to normalize off-system sales?

A: The same model used to normalize test year fuel and purchased power (MIDAS^{TM}) was used to normalize off-system sales. The model was configured to simulate off-system sales for the GMO system based on the same assumptions used to normalize fuel and purchased power costs. The model simulates sales to the wholesale market when there is GMO generation capacity available above that required to meet native load obligations and the market price for power is greater than the available generation capacity's marginal cost. This calculation is made on an hour-by-hour basis. Normalized off-system sales revenues for this case can by found in Schedule BLC-4 (HC). The related generating costs are also included in this Schedule.

Q: Were there any other adjustments made related to wholesale transactions?

A: Yes, adjustments were made for SPP line loss charges and SPP Revenue Neutrality Uplift ("RNU") charges.

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. GMO pays these line loss charges on a portion of its off-system sales. In addition, GMO receives a share of the loss charges collected from SPP.

Q: Why is it appropriate that GMO make adjustments for SPP line loss charges?

A: GMO 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 MIDAS™ model used to determine the off-system sales assumes the sales are made at the generator bus, therefore, the SPP line loss charges are not included in the model results. GMO also receives loss revenues from SPP. These revenues are also not reflected in MIDAS™ and therefore an adjustment is appropriate.

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

A: The SPP line loss charges and revenues included in this case are the actual 12 months ending November 2011 line loss charges and revenues from SPP. This adjustment is shown in Schedule BLC-5.

Q: What are SPP's RNU 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 charge or 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 GMO made an adjustment for SPP's RNU charges?

A: As a participant in the SPP EIS market, GMO is exposed to RNU charges. GMO books RNU revenue as off-system sales. This sales revenue is not included in the MIDAS™ model used for determining off-system sales. GMO books RNU charges as a purchased power expense. GMO's modeled purchased power expense does not include this expense. As such, the net SPP RNU charges have been included as an adjustment to off-system sales. 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-5.

Q: How were the results of the modeling allocated between the service territories of MPS and L&P?

A: The modeling results were allocated based upon the methodology included in Schedule 3 to the Non-Unanimous Stipulation and Agreement reached in the settlement of GMO's rate case in Case No. ER-2009-0090.

III. CROSSROADS TRANSMISSION COSTS

Q: Please briefly describe the purpose of this portion of your direct testimony.

A: The purpose of this portion of my testimony is to provide support for the inclusion of Crossroads related transmission service costs in the cost of service.

Q: What are transmission service costs?

A: At a very high level, there are two major transportation related costs for a major generating facility. These include the cost to move fuel to the generating facility and the cost to move the electricity generated to the retail customer service area. Both components are required.

Q: Please describe the transportation related costs for Crossroads.

A: The Crossroads generating facility is a natural gas fired plant located outside the SPP footprint. It requires both the transport of natural gas to the plant and the transport of electricity generated to the GMO territory. Company witness Wm. Edward Blunk describes the cost of gas transportation in detail in his direct testimony in this case. In order to move the electricity generated by the plant to GMO, electric transmission service is needed on the Entergy and SPP transmission systems.

The annual cost for firm gas transportation is **[redacted]** and the annual cost for firm transmission service is approximately **[redacted]**.

Q: Is GMO currently recovering the transportation related costs for Crossroads?

A: Not entirely. GMO currently recovers the cost of firm gas transportation, but not the cost of firm transmission service.

Q: Why does GMO not recover the cost of firm transmission service for Crossroads?

A: In the previous GMO rate case (Case No. ER-2010-0356) the Commission rejected the recovery of firm transmission service.

Q: Is it reasonable to get recovery of the firm transmission costs?

A: Yes.

Q: Please explain.

A: To some degree, all major generating facilities will have costs related to transporting fuel and electricity. Apparently as a result of the plant's physical location outside of the SPP region, the Commission denied recovery of the transmission related costs for Crossroads. At the same time the Commission denied transmission cost recovery, the Commission also reduced the value of the plant to that of similar facilities that were sold in 2006 in Illinois. Had these facilities in Illinois been purchased by GMO, there would have been significant firm transmission related costs (assuming it was even available) for these plants as well. While the cost of firm transmission for Crossroads is approximately $5.2 million per year, the cost of firm transmission for the Illinois facilities would be approximately $9.7 million per year.

The following table compares the total annual transportation related costs (both for gas and electricity) for Crossroads, the Illinois facilities, and for a similar sized facility located at GMO's South Harper facility. Detail on the cost of gas transportation costs is included in the Direct Testimony of Company witness Wm. Edward Blunk.

Transportation Service	Crossroads	Goose Creek/ Raccoon Creek	GMO Site
Transmission	$5.2 million	$9.7 million	$0
Fuel	** [redacted] **	Unknown	** [redacted] **
Total	** [redacted] **	Minimum $9.7 million	** [redacted] **

Given that the transportation costs are generally lower in total for Crossroads, it is reasonable that the Commission allow recovery of these costs.

Q: If the Commission found that some figure below **[redacted] was the likely cost of gas and electric transmission for additional capacity at South Harper, should GMO be allowed to recover this figure in rates?**

A: Yes. As Company witness Wm. Edward Blunk explains in his Direct Testimony and as I have stated above, any major generating facility will have costs related to transporting fuel and electricity. Both costs must be considered. If the Crossroads capacity was located at South Harper, the cost for transmission would have been likely lower than from its actual location in Mississippi; however, the cost of gas supply would have been much higher. It is unreasonable to accept benefits of the low cost of gas service at Crossroads while ignoring the cost of electric transmission. Therefore, whatever figure the Commission finds reasonable with regards to total costs to transport gas and electricity must be allowed as an appropriate element of GMO's cost recovery.

IV. ELECTRIC UTILITY FUEL AND PURCHASED POWER COST RECOVERY MECHANSIM

Q: Regarding GMO's request for approval to continue its FAC, which portions of the Electric Utility Fuel and Purchased Power Cost Recovery Mechanism are you addressing in your testimony?

A: I will address all or portions of 4 CSR 240-3.161(3)(P), (Q), (R) and (S). Requirement (P) addresses the resources the utility expects to use in the next four (4) true-up years. Requirement (Q) addresses heat rate tests results. Requirement (R) addresses GMO's long-term resource planning and requirement (S) addresses forecasted environmental investments.

Q: Please describe your support for the requirements in 4 CSR 240-3.161(3)(P).

A: The supply-side and demand-side resources that GMO expects to use to meet its load over the next four (4) true-up years is included in Schedule BLC-8 (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 GMO'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.

Q: What is the status of the heat rate tests per the requirements in 4 CSR 240-3.161(3)(Q)?

A: Heat rate tests were completed in 2010 and 2011. Schedule BLC-6 (HC) contains the results of these heat rate tests. Testing has been scheduled for 2012 and 2013. Schedule BLC-7 contains this schedule.

Q: Please provide your support for 4 CSR-3.161(3)(R).

A: GMO 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 GMO's last IRP prepared?

A: GMO prepared and filed its latest preferred resource plan in July 2011 under Case No. EE-2009-0237.

Q: When will the next GMO IRP be prepared?

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

Q: What are the Company's forecasted environmental investments per 4 CSR 240-3.161(3)(S)?

A: Given the significant uncertainty surrounding future environmental regulations, GMO evaluates the need for future environmental control equipment on an ongoing basis. GMO is currently evaluating the investments necessary to comply with EPA's recently released Mercury and Air Toxics Standard ("MATS"). Potential MATS related investments include:

Sibley 1, 2 and 3 Activated Carbon Injection ("ACI"): **[redacted]**

Sibley 3 Precipitator Improvements: **[redacted]**

Lake Road Unit 4/6 ACI and Baghouse: **[redacted]**

Since the MATS compliance strategy is currently 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 KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	)))	Case No. ER-2012-0175

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 KC&PL Greater Missouri Operations Company consisting of Sixteen (16) 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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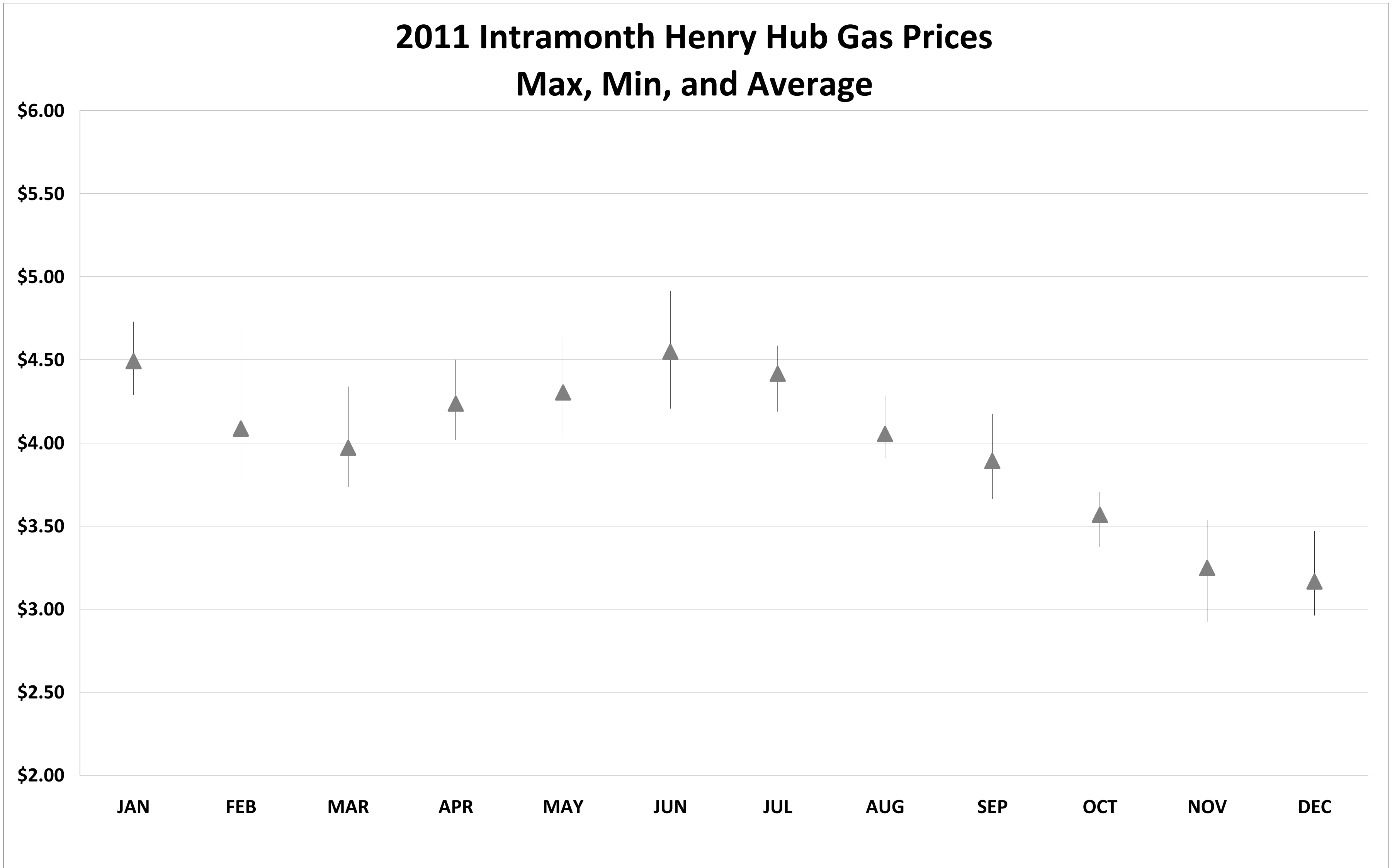

Schedule BLC-2

SCHEDULES BLC-3 thru BLC-4

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Kansas City Power & Light - Greater Missouri Operations

Adjustment for SPP Line Loss Charges & Revenues and Net RNU
Schedule BLC - 5

SPP Line Loss Revenue & Expense and Net RNU

Month	SPP Loss Revenues	Net RNU	Total Revenue	SPP Loss Expense
Dec 2010	$ 36,202	$ 66,794	$ 102,996	$ 686
Jan 2011	$ 50,485	$ 37,868	$ 88,353	$ -
Feb 2011	$ 34,138	$ 69,637	$ 103,775	$ -
Mar 2011	$ 22,881	$ 59,945	$ 82,826	$ -
Apr 2011	$ 27,177	$ 29,584	$ 56,761	$ 61
May 2011	$ 32,602	$ 29,070	$ 61,673	$ 263
June 2011	$ 37,873	$ 49,177	$ 87,050	$ 784
July 2011	$ 47,170	$ 78,778	$ 125,948	$ -
Aug 2011	$ 45,760	$ 67,330	$ 113,090	$ 91
Sept 2011	$ 33,488	$ 22,073	$ 55,561	$ 208
Oct 2011	$ 36,656	$ 3,183	$ 39,839	$ -
Nov 2011	$ 39,250	$ (22,107)	$ 17,143	$ 278
12 ME 12/2010	$ 443,683	$ 491,332	$ 935,015	$ 2,371

SCHEDULE BLC-6

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GMO FAC Heat Rate Testing Schedule

Unit	Baseline test date	2010 Testing Completed	2011 Testing Completed	2012 Testing Schedule	Next test date
Crossroads 1	8/20/2008	8/2/2010	-	8/2/2012	-
Crossroads 2	8/19/2008	8/2/2010	-	8/2/2012	-
Crossroads 3	8/20/2008	8/2/2010	-	8/2/2012	-
Crossroads 4	8/19/2008	8/3/2010	-	8/3/2012	-
Greenwood 1	8/13/2008	8/10/2010	-	8/10/2012	-
Greenwood 2	8/13/2008	8/12/2010	-	8/12/2012	-
Greenwood 3	8/14/2008	7/30/2010	-	7/30/2012	-
Greenwood 4	8/14/2008	7/29/2010	-	7/29/2012	-
Lake Road 1	4/15/2009	-	5/10/2011	-	5/10/2013
Lake Road 2	6/11/2008	6/11/2010	-	6/11/2012	-
Lake Road 3	6/18/2008	9/9/2010	-	9/9/2012	-
Lake Road 4	6/26/2008	6/11/2010	-	6/11/2012	-
Lake Road 5	5/29/2008	4/20/2010	-	4/20/2012	-
Lake Road 6	4/16/2009	-	5/5/2011	-	5/5/2013
Lake Road 7	4/17/2009	-	6/23/2011	-	6/23/2013
Lake Road Boiler 1	1/23/2009	-	2/17/2011	-	2/17/2013
Lake Road Boiler 2	5/19/2009	-	9/29/2011	-	9/29/2013
Lake Road Boiler 3	1/26/2009	-	7/12/2011	-	7/12/2013
Lake Road Boiler 4	5/20/2009	-	6/29/2011	-	6/29/2013
Lake Road Boiler 5	3/26/2009	-	3/29/2011	-	3/29/2013
Lake Road Boiler 8	9/12/2008	9/22/2010	-	9/22/2012	-
Nevada	5/11/2009	-	9/29/2011	-	9/29/2013
Ralph Green 3	8/28/2008	8/27/2010	-	8/27/2012	-
Sibley 1	8/5/2008	7/13/2010	-	7/13/2012	-
Sibley 2	8/5/2008	7/13/2010	-	7/13/2012	-
Sibley 3	8/5/2008	6/18/2010	-	6/18/2012	-
South Harper 1	8/5/2008	7/22/2010	-	7/22/2012	-
South Harper 2	8/5/2008	7/20/2010	-	7/20/2012	-
South Harper 3	8/4/2008	7/21/2010	-	7/21/2012	-
Joint Ownership					
Jeffrey 1 (8%)	8/28/2008	6/25/2010	-	6/25/2012	-
Jeffrey 2 (8%)	5/29/2009	-	6/7/2011	-	6/7/2013
Jeffrey 3 (8%)	2/5/2009	12/10/2010	-	12/10/2012	-
Iatan 1 (18%)	7/16/2009	-	12/6/2011	-	12/6/2013
Iatan 2 (18%)	12/19/2010	12/3/2010	-	12/3/2012	-

SCHEDULE BLC-8

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