Exhibit No.:	
Issue:	Fuel Expense; Purchased Power Expense Adjustments to Projected Off-System Sales Margins
Witness:	Burton L. Crawford
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2009-____
Date Testimony Prepared:	September 5, 2008

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2009-____

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
September 2008

Certain Schedules Attached To This Testimony Designated ("HC")
Have Been Removed
Pursuant to 4 CSR 240-2.135.

DIRECT TESTIMONY

OF

BURTON L. CRAWFOD

Case No. ER-2009-____

Q: Please state your name and business address.

A: My name is Burton L. Crawford. My business address is 1201 Walnut, Kansas City, Missouri 64106.

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 Manager, 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 ("Commission") or before any other utility regulatory agency?

A: Yes, I have. I provided testimony in KCP&L's 2007 general rate proceeding, Case No. ER-2007-0291. I also provided testimony in Case No. EO-2006-0142, which pertained to KCP&L's application to join Southwest Power Pool, Inc. ("SPP"), a Regional Transmission Organization. I also provided testimony in Case No. ER-2006-0314, KCP&L's 2006 general rate case, which began the implementation of the Company's regulatory plan approved by the Commission in 2005.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the level of fuel expense and purchased power expense, the process of normalizing such expenses, wholesale contract customer revenues, and adjustments to the projected off-system sales margins for purchases for resale and for SPP line loss charges.

I. Energy Price Forecasts

Q: Could you 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 these 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 ("FERC") Form 1 data, U.S. Energy Information Administration ("EIA") 411 reports, and Continuous Emissions Monitoring system ("CEM") data compiled by the U.S. Environmental Protection Agency ("EPA"), as their source. 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, including capacity, heat rate, fuel type, variable operations and maintenance costs, outage rates, emissions rates, and start-up costs. 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, assesses the constraints through their analyses of regional assessments from the various reliability councils.

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 fairly reliable, so identifying a reasonable unit to base an hourly price on is something that can be done with a fair amount 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 North Southwest Power Pool ("N-SPP").

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

A: Relative to natural gas prices, coal prices are less volatile and the model inputs are based on actual reported fuel costs, so it is not as difficult to predict coal's impact on power prices when it is the marginal fuel. Natural gas prices are much more volatile and difficult to predict.

Q: What is your opinion of KCP&L's power price forecasts?

A: The power price forecasts are fairly accurate when the forecasts of natural gas prices are accurate. Natural gas is the marginal fuel in N-SPP for 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) presents how closely KCP&L's power price forecast tracked prices that we observed in the N-SPP market. This Schedule shows a MIDAS simulation of 2007 wholesale power prices based on the average spot gas price for each month. Schedule BLC-1 (HC) is Highly Confidential as it contains market-specific information related to services and their prices offered by KCP&L in competition with other utilities and market participants. It is worth noting that 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, such volatility would affect KCP&L's ability to track actual market prices with the MIDAS simulation. Schedule BLC-2 illustrates the monthly volatility of natural gas prices at the New York Mercantile Exchange ("NYMEX"). In addition to intra-month gas prices, there is another factor that would influence the MIDAS simulation versus the actual market. The actual hourly regional demand data for 2007 is not yet available. The unavailability of actual regional load data is not an issue when normalizing wholesale market prices since it is more appropriate to use a representation of normal market conditions. Our simulation, therefore, used the forecasted hourly demand that is part of the National Database that I discussed earlier.

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™ 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. 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 KCP&L 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 case.

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: KCP&L makes capacity and energy sales to City Utilities of Springfield and the City of Independence. The revenue for these transactions and the associated fuel expense is imbedded in the modeling results provided in Schedule BLC-4 (HC). They are not included in the off-system sales described in the Direct Testimony of KCP&L witness Michael M. Schnitzer.

Q: Please describe the normalization of fuel prices.

A: The normalized fuel prices used in the modeling were developed by KCP&L witness Wm. Edward Blunk and are described in detail in his Direct Testimony. These normalized 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 modeling wholesale energy market prices.

Q: Please describe the normalization of maintenance outages.

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, the Wolf Creek Nuclear Generating Station's refueling and maintenance outages occur every eighteen months, either in the spring or fall. Thus, every third year Wolf Creek is available for the entire year. As a result, 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, KCP&L computed the total number weeks that a unit would be scheduled 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. This approach resulted in a total amount of generation capability "lost" due to maintenance activities that is approximately equal to the long-term average. Schedule BLC-3 (HC) contains the maintenance schedule that was used for the normalization. Schedule BLC-3 (HC) is Highly Confidential as it contains market-specific information related to services provided by KCP&L in competition with other utilities and market participants.

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

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 March 31, 2009. First, long-term purchase power contract levels were adjusted to reflect the capacity levels that are committed effective March 31, 2009.   Second, any temporary limitations of generating capacity that currently exist and that are expected to be mitigated by that time have been eliminated. Likewise, the generating capacity of existing units has been adjusted for the anticipated impacts of plant modifications, such as installation of pollution controls.

Q: How was the generation from the Spearville Wind Energy Facility modeled in this rate case?

A: The wind generation was modeled based upon the projected output for the Spearville Wind Energy Facility. The actual wind profile data was used to develop projected typical weekly energy output data. This generation was included in the Company's total generation resource mix.

Q: What is your opinion of the results of this modeling?

A: The modeling assumptions for operating heat rates, equivalent forced outage rates, capacity, and other key inputs are based upon historical averages. After making the normalization adjustments described previously, I believe the results are reasonable.

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-2, attached to the Direct Testimony of KCP&L witness John P. Weisensee (Adj-38 & Adj-40).

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 witness Michael M. Schnitzer?

A: Yes. KCP&L has included an adjustment to the computed 25^{th} percentile 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. Additionally, an adjustment is made for SPP line loss charges.

Q: What are Purchases for Resale?

A: These transactions represent KCP&L wholesale sales that are supplied by purchased power as compared to wholesale sales supplied by generation owned by the Company.

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 Market ("EIS") was supplied by a bilateral (wholesale) purchase. These are shown as Transaction Type 1 in Schedule BLC-5 (HC). These transactions began in February 2007 with the implementation of the SPP EIS market. Therefore, the proposed adjustment annualizes the test period values.

(2) Transactions where a bilateral sale was supplied by a bilateral purchase. KCP&L makes day-ahead purchases based upon its expected loads, availability of firm transmission for purchases, availability and price of energy for purchase, and generating resource availability in an effort to limit its exposure to the real-time, hourly spot-market purchases, 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 is 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 (HC).

(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 simultaneously purchase from the SPP EIS market and 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, and creates 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 (HC).

(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 (HC).

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 experiences all four of the wholesale transactions described above. The total net revenue from these transactions (revenue less cost) is typically negative. The cost of these transactions is not reflected in the off-system sales margin analysis performed by 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 for recovery.

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

A: The amount of Purchases for Resale included in this case is based on actual Purchases for Resale during the test year. These amounts are shown in Schedule BLC-5 (HC).

Q: Since KCP&L proposes to return any off-system sales margins over the 25th percentile to their retail customers, will Purchases for Resale be included as part of the margin tracking process?

A: Yes. KCP&L proposes to include Purchase for Resale transactions 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 the 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 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 the fuel cost needed to support off-system sales. Fuel cost is combined with the cost of purchased power (as determined by PA) to calculate 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 Michael M. Schnitzer to determine the 25th percentile of 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 Michael M. Schnitzer?

A: In addition to the Purchases for Resale adjustment, KCP&L has included SPP line loss 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 Mr. 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 net SPP line loss charge amount included in this case is $2,035,923. This is the actual 2007 test year's net line loss charge from SPP, annualized for the fact that the SPP

EIS market was only in place for 11 months of the test year. This adjustment is show in Schedule BLC-6.

Q: Please summarize the proposed adjustments to Mr. Schnitzer's 25th percentile off-system sales margins?

A: The total adjustments to the off-system sales margin calculated by Mr. Schnitzer can be found in Schedule BLC-7 (HC).

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company to Modify Its Tariff to Continue the Implementation of Its Regulatory Plan	)))	Case No. ER-2009-____

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 Manager, 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 fifteen (15) 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 5th day of September ~~August~~ 2008.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4, 2011

" NOTARY SEAL "
Nicole A. Wehry, Notary Public
Jackson County, State of Missouri
My Commission Expires 2/4/2011
Commission Number 07391200

SCHEDULES BLC-1

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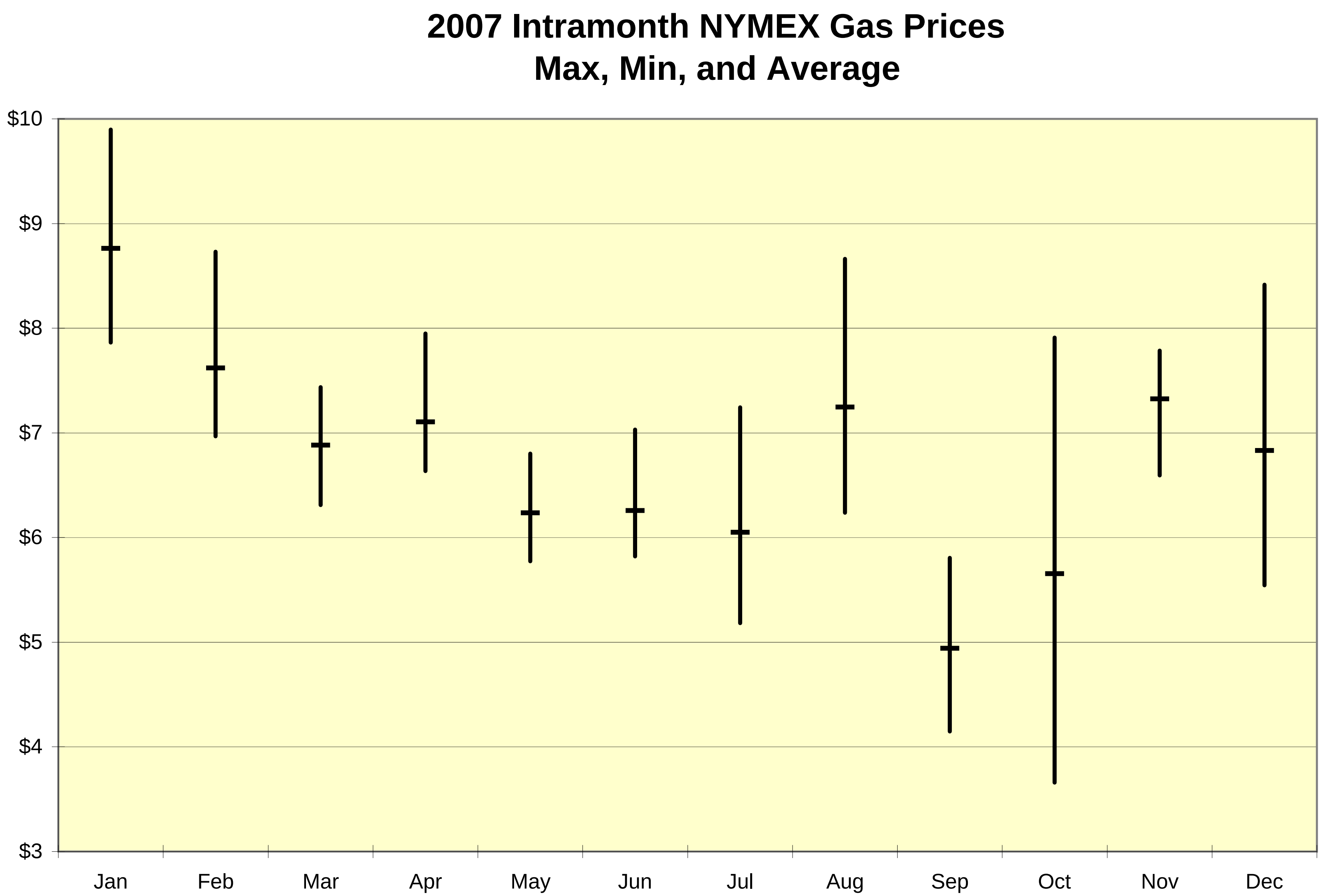

Schedule BLC-2

SCHEDULES BLC-3 THROUGH BLC-5

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Adjustment for SPP Line Loss Charges & Revenues
Schedule BLC-6

2007 Actuals - SPP Line Loss Charges & Revenues

	Loss Charge	Loss Revenue
Jan		44,393
Feb	129,319	88,892
Mar	196,211	85,376
Apr	282,642	98,222
May	222,398	125,925
June	224,809	119,298
July	168,233	87,808
August	196,336	122,315
September	324,180	101,843
October	372,762	97,397
November	533,552	183,608
December	394,919	131,211
Total	3,045,360	1,286,287
Annualized	3,322,210	1,286,287
Net Adjustment		2,035,923

SCHEDULE BLC-7

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