Exhibit No.:
Issue: Fuel, Purchased Power, Wholesale Sales, FAC Support
Witness: Burton L. Crawford
Type of Exhibit: Direct Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No.: ER-2018-0145
Date Testimony Prepared: January 30, 2018

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2018-0145

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
January 2018

Certain Schedules Attached To This Testimony Designated "(CONFIDENTIAL)" Contain Confidential Information.
All Such Information Should Be Treated Confidentially
Pursuant To 4 CSR 240-2.135.

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

Case No. ER-2018-0145

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 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 revenue requirement schedules included 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 to continue use of the Fuel Adjustment Clause ("FAC"). I specifically address all or a portion of the requirements of 4 CSR 240-3.161(3)(P), (Q), (R), and (S).

I. ENERGY PRICE FORECASTS

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

A: KCP&L utilizes the MIDAS™ model, which is similar to other fundamental price forecasting models that are commonly used in the industry. MIDAS™ is provided by Ventyx (formerly Global Energy). The Transact Analyst™ component of MIDAS™ generates regional prices by modeling power flows within and between various energy markets, transaction areas, North American Electric Reliability Corporation ("NERC") Sub-Regions, and NERC Regions. Power flows are determined based on the relative loads, resources, marginal costs, transactions costs, and intertie limits between the areas or regions. Transactions occur on an hourly basis for 8,760 hours per year.

Q: What are the primary inputs to the model?

A: The model utilizes a sizeable input dataset, referred to as the National Database. It is populated with assumptions about market supply, demand, and transmission. The bulk of the input assumptions use Federal Energy Regulatory Commission Form 1 data, Energy Information Administration 411 reports, and Continuous Emissions Monitoring system data compiled by the Environmental Protection Agency ("EPA"), as their sources. The demand data includes projected hourly demand for virtually every utility in the Eastern Interconnect. The supply data contains a representation of 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 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 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 frequently 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"). Wind generation is showing an increasing number of hours as the marginal resource in 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 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 December 2016 through November 2017 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 December 2016 through November 2017. 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^{TM} model for its production cost model.

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

A: This is the same modeling software used to generate the market price forecasts described previously. For purposes of running the production cost 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 against these market prices to make sales to the integrated marketplace when it is economic to do so. 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 system requirements normalization 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 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 Jessica Tucker and are described in detail in her Direct Testimony. These fuel prices were input into the model on a plant-specific basis and were then used in the normalized production cost modeling. The natural gas prices provided by Ms. Tucker 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. They are Spearville 3, Cimarron, Waverly, Slate Creek, Osborn, Rock Creek wind farms and Central Nebraska Public Power and Irrigation District (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, the results of this modeling should likewise result in reasonably accurate results.

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

A: The SPP IM consists of a day-ahead energy market with transmission congestion rights, a real-time energy balancing market, and an operating reserve market. The IM 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, the regional balancing of supply and demand, and cost-effectiveness. In March 2014, the SPP IM replaced SPP's Energy Imbalance Service Market, which was in operation since 2007.

Q: How does the 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 being sold off-system. 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.

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

The production cost modeling performed for this case emulates the operations of the SPP-IM.

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 expenses were 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, CS-25, and R-35).

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, line loss payments related to the Missouri Iowa Nebraska Transmission (MINT) line, SPP Revenue Neutrality Uplift 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 services from the SPP-operated ancillary services 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 for the twelve months ending September 2017. These values will be updated to actual amounts for the most recent 12 months at true-up.

Q: What are the MINT line loss payments?

A: These are payments made to Associated Electric Cooperative (AEC) for transmission losses on the MINT line. AEC provides coverage of the losses in-kind and the Company reimburses them for its share.

Q: What amount of MINT line loss payments has KCP&L included in this case?

A: The line loss payments included in this case is based on the actual payments for the twelve months ending September, 2017. These values will be updated to the actual amounts for the most recent 12 months at true-up.

Q: What are SPP's Revenue Neutrality Uplift ("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 twelve months ending September 2017 net SPP RNU charges. This adjustment is shown in Schedule BLC-4 (HC). This RNU 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 the SPP IM was developed, 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, during the period twelve months ending September 2017, 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 amount can be found in Schedule BLC-4 (HC). Similar to the other SPP related adjustments, 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 continued use 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(3) (P), (Q), (R) and (S). Requirement (P) addresses the projected generation and Demand Side Management dispatch over the next four years, requirement (Q) addresses heat rate test results, requirement (R) addresses the long-term resource planning process, and requirement (S) addresses forecasted environmental investments.

Q: Please describe your support for compliance with 4 CSR 240-3.161(3) (P).

A: 4 CSR-3.161(3) (P) 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).

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 supplied the heat rate test results for its generating units required per 4 CSR 240-3.161(3) (Q)?

A: Yes. Heat rate test results conducted within the previous 24 months are provided in Schedule BLC-6 (HC) and Schedule BLC-7(HC).

Q: Please provide your support for 4 CSR 240-3.161(3) (R).

A: 4 CSR 240-3.161(3) (R) 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 in place. 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 June 2017 in Case No. EO-2017-0229. The Commission closed the case on August 11, 2017.

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

A: Under the current IRP rule, the next KCP&L IRP update is to be filed in April 2018. This filing will be a triennial filing.

Q: Please provide your support for 4 CSR 240-3.161(3)(S).

A: 4 CSR 240-3.161(3)(S) 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 allowances purchases and sales; ….

At this time, KCP&L has no forecasted environmental investments that would impact emission allowances costs or sales margins.

The forecasted emission allowance purchases required by 4 CSR 3.161(3) (S) can be found in the Direct Testimony of Company witness Jessica Tucker.

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-2018-0145

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 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 29th day of January 2018.

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

SCHEDULE BLC-1

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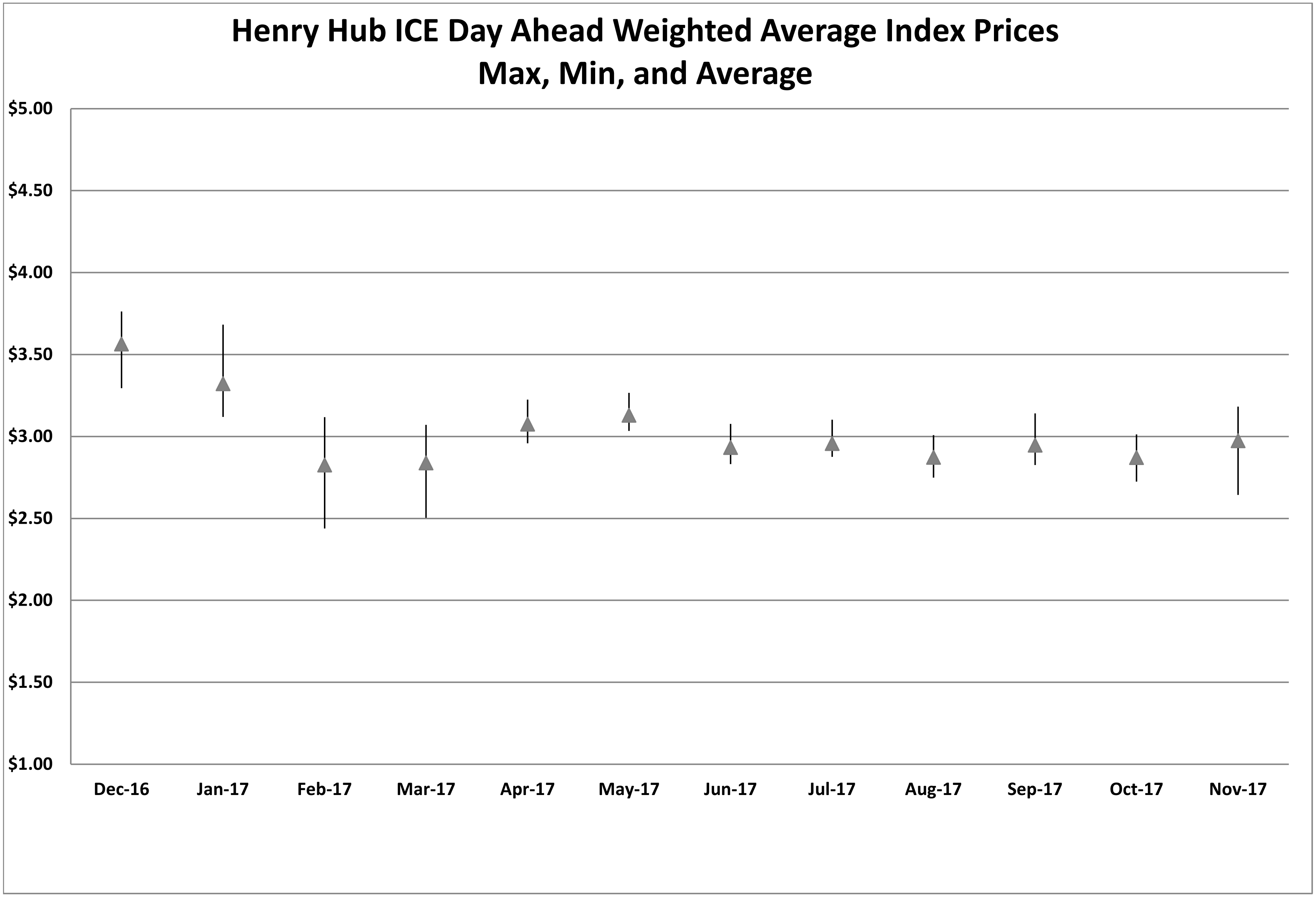
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SCHEDULE BLC-3

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SCHEDULE BLC-4

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