Exhibit No.: 104NP
Issue: Fuel Prices; Fuel Inventory; Fuel Adjustment Clause; Price Forecasts for La Cygne Environmental Project
Witness: Wm. Edward Blunk
Type of Exhibit: Rebuttal Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No.: ER-2014-0370
Date Testimony Prepared: May 7, 2015

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2014-0370

REBUTTAL TESTIMONY

OF

WM. EDWARD BLUNK

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
May 2015

"[redacted]**" Designates "Highly Confidential" Information Has Been Removed.**

REBUTTAL TESTIMONY

OF

WM. EDWARD BLUNK

Case No. ER-2014-0370

Q: Please state your name and business address.

A: My name is Wm. Edward Blunk. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: Are you the same Wm. Edward Blunk who pre-filed Direct Testimony in this matter?

A: Yes, I am.

Q: What is the purpose of your Rebuttal Testimony?

A: I will respond to the Direct Testimony of: Rachel S. Wilson on behalf of Sierra Club regarding price forecasts used in the analysis supporting the decision to undertake the La Cygne Environmental project, Lena M. Mantle on behalf of the Office of the Public Counsel regarding the fuel adjustment clause ("FAC"), Michael L. Brosch on behalf of Midwest Energy Consumers' Group ("MECG") regarding the FAC, and the Missouri Public Service Commission ("MPSC" or "Commission") Staff ("Staff") (Staff Report Revenue Requirement Cost Of Service and Staff's Rate Design And Class Cost-Of-Service Report) regarding the FAC.

I. Price Forecasts Used in the Analysis for the La Cygne Environmental Project

Response to Rachel S. Wilson – Sierra Club

Q: Which portions of Sierra Club witness Wilson's Direct Testimony will you address?

A: Ms. Wilson's testimony related to the fuel price forecast used for Kansas City Power & Light Company's ("KCP&L" or "Company") analysis can be roughly divided into two areas of focus. The first grouping is criticisms other people made some years ago in our Kansas predetermination proceeding, Kansas Corporation Commission ("KCC") Docket No. 11-KCPE-581-PRE ("581 Docket"). The second grouping is how Energy Information Administration's ("EIA") outlook for natural gas prices has changed since 2011. I will address each topic in turn.

Q: Did you respond to those same criticisms in the 581 Docket?

A: Yes. I was the Company's witness on those issues in the 581 Docket.

Q: At page 9 Ms. Wilson said "Mr. Schlissel testified that KCP&L's analysis relied on natural gas price forecasts that were more than 13 months out-of-date, and that revised forecasts had been issued that were significantly lower than the earlier forecast on which KCP&L relied." Is that a fair representation of what Mr. David Schlissel said in the 581 Docket?

A: No. The subtle difference between Mr. David A. Schlissel's exact words and Ms. Wilson's restatement is significant. Ms. Wilson left out the key phrase "in part". What Mr. Schlissel said was,

> KCP&L's modeling analyses also are biased in favor of the retrofitting of La Cygne Units 1 and 2 by the use of natural gas prices that KCP&L are based, at least **in part**, on public forecasts from the U.S. Department of Energy that are out-of-date and that have been replaced by significantly

lower forecasts. The Company's modeling analyses also did not reflect a reasonable range of potential prices for coal.[1] [emphasis added]

Q: Why is the phrase "in part" significant and relevant to Ms. Wilson's rehash of Mr. Schlissel's concern?

A: KCP&L uses composite forecasts and one of the reasons we use composite forecasts is we too share Mr. Schlissel's concern that at some point in time an input forecast will become stale. We update our fuel and emission price forecasts frequently because we use them for our internal financial projections and operational decisions. The issue of stale forecasts is one of the reasons we use a composite forecast.

Q: How does your composite forecast deal with the concern that a particular forecast might be out-of-date?

A: Forecasts are issued periodically by the various forecasting services and public agencies such as EIA. The timing of any filing or analysis determines the available forecasts. For example, EIA issues its forecast annually. Unless an analysis can be timed perfectly to the issuance of such forecast, the forecast can be up to one year old when used. Since any analysis needs to be completed before a filing is made, it is likely that at least one of the input forecasts will be a year or more old when the filing is made.

One of the benefits of using a composite forecast is that it has a higher frequency of updates than individual forecasts. The composite forecast is updated whenever one of the panel forecasts is updated. While the EIA's Annual Energy Outlook ("AEO") 2010 that was incorporated in our October 2010 composite forecast was the most current version of the AEO at that time, it was not as fresh as other forecasts in the portfolio.

[1] Direct Testimony of David A. Schlissel on behalf of Great Plains Alliance for Clean Energy, 581 Docket, p. 3, and similar at pp. 4 and 18.

The freshest forecast was from Energy Ventures Analysis ("EVA") who had just issued their then new long-term outlook for natural gas. The composite forecast used in the analysis was prepared within a month of the early release of EVA's forecast. If we had used a single source forecast, Mr. Schlissel's point and Ms. Wilson's rehash of Mr. Schlissel's point would warrant further consideration, but the composite methodology effectively mitigates the issue.

Q: Did the KCC address Mr. Schlissel's concerns about your natural gas price forecast in its order?

A: Yes.

Q: What did the KCC order say regarding Mr. Schlissel's concerns?

A: On page 21 the relevant part of paragraph 36 reads as follows:

> Likewise GPACE's witness Schlissel testified, "... a long term forecast is basically unreliable once you've said it." The complaints raised by the parties about the decision-making process used by KCP&L boiled down to:
>
> - Was the future price projection for various components reasonable (*e.g.*, was the price series of natural gas used in the model too high and, thus, unreasonable because it was biased against alternatives that relied on natural gas)? [2]
>
> [footnotes omitted]

The KCC's conclusion is recorded in paragraph 40 on page 22 where the KCC stated:

> The Commission concludes that, based on the evidence presented in this matter, KCP&L's modeling effort and conclusion to retrofit the La Cygne units is reasonable, reliable and efficient. While concerns were expressed regarding some assumptions made in KCP&L's modeling for the La Cygne Project, witnesses during the hearing discussed in detail the planning process that when (sic) into the modeling. KCP&L's management is not required to be perfect, just prudent. The Commission concludes that none of the challenges made to KCP&L's proposed project rose to a level that would invalidate the decision reached by KCP&L, namely that a retrofit of the La Cygne units was the least cost (*i.e.*,

[2] E581 Docket, Order dated Aug. 19, 2011, p. 21.

> efficient) alternative. Indeed, KCP&L's retrofit conclusion was validated by Westar and Bates-White, which used different simulation models and different price projections, but nevertheless concluded that a retrofit was the least cost alternative.[3]

Q: Ms. Wilson consistently points to the EIA's AEO. Does your composite forecast include EIA's AEO?

A: Yes. EIA's AEO was a part of our composite forecast in 2011 and continues to be a part of our composite forecasts.

Q: Have you observed any particular issues with EIA's AEO as a forecast?

A: Yes. EIA's AEO assumes that current laws and regulations are maintained throughout the projections. It also assumes that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates. With those assumptions, the EIA is attempting to provide a policy neutral baseline that can be used to analyze policy initiatives. EIA explained this quite well in its 2010 AEO when comparing that AEO to other forecasts.

> The variation among projections of natural gas consumption, production, imports, and prices (Table 13) can be significant. This variation results from differences among the assumptions that underlie the different projections. For example, the *AEO2010* Reference case generally assumes that current laws and regulations will continue through the projection period as enacted, whereas some of the other projections assume the enactment of new public policy over the next 25 years.[4]

This is and has been a fundamental assumption of the AEO for years. In the most recent AEO, EIA says something very similar.

> Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The AEO2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions

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[3] Id., p. 22.

[4] EIA, *Annual Energy Outlook 2010*, pp. 88-90, available at http://www.eia.gov/oiaf/archive/aeo10/index.html.

> in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. The main cases in AEO2015 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.[5]

Q: How does that assumption affect the AEO?

A: No matter how probable, the AEO Reference case ignores potential law or regulation that would affect production costs, use of (i.e., demand for), or tax on any of the commodities it forecasts.

Q: Does that mean the AEO is biased?

A: Yes. This is a known bias in the AEO.

Q: Given that bias, why do you include the AEO in your composite forecast?

A: It is reasonable to believe that recognized and unrecognized biases in EIA's forecast are balanced or mitigated by recognized and unrecognized biases in the other forecasts used to construct KCP&L's composite forecast. In other words, the composite forecast approach balances or mitigates the biases and random errors embedded in EIA's forecast with the biases and random errors in the other forecasts included in the composite forecast. This is one of the reasons a composite forecast is considered a best practice.

Q: What does all of this mean with regards to Ms. Wilson's analysis where she relies exclusively on EIA's AEO for her gas price forecast?

A: It means two things. First, Ms. Wilson's freshest forecast was out-of-date. It also means that her forecast was biased.

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[5] EIA, *Annual Energy Outlook 2015*, p. iii, available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

Q: Why was Ms. Wilson's forecast out-of-date?

A: Ms. Wilson's testimony was filed on April 2, 2015. AEO 2015 was released April 14, 2015. AEO 2014 was released in April 2014 which means the freshest forecast she relied on was a year old when her testimony was filed.

Q: At page 30 Ms. Wilson presents the following figure. What does this chart show us?

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[redacted] **

HIGHLY CONFIDENTIAL Figure 1. KCP&L Natural Gas Price Forecast Used in 581 Docket Compared to AEO 2012, AEO 2013 and AEO 2014.

A: Frankly I think Ms. Wilson's chart shows the robustness of KCP&L's forecast methodology. Even with the recent downward price shift driven by shale gas, by about 2016, which would be the first full year of operating the new environmental controls at La Cygne, AEO 2014 is within our forecasted range of natural gas prices.

Q: How was Ms. Wilson's forecast biased?

A: By relying exclusively on the AEO, Ms. Wilson was limited to the assumptions and views of the AEO. As I discussed earlier, the AEO assumes there will be no new regulations or laws. That means the Clean Power Plan which was proposed about two months after the AEO 2014 was released was not included in Ms. Wilson's forecast. In this case, that assumption of no new regulations means there was no inclusion of the likelihood, nor magnitude, of the increases in the price of natural gas driven by the implementation of the Clean Power Plan ("CPP"). The CPP includes as one of its four building blocks the transfer of generation from coal to natural gas which will increase the usage of (i.e., demand for) natural gas. That increased demand will likely drive up the price for natural gas. In other words, Ms. Wilson's natural gas price forecast is probably biased low.

Q: What is your position regarding Ms. Wilson's exclusive reliance on EIA's AEO?

A: All forecasts are attempting to see into an uncertain future. For issues as complex as those included in the La Cygne retrofit decision, reliance on a single forecast with no consideration for the range of possible outcomes is unreasonable, especially when that single forecast is one that deliberately excludes the impacts of potential law and regulation.

II. Fuel Adjustment Clause

Response to Commission Staff, Lena M. Mantle – OPC, and Michael Brosch - MECG

Q: What parts of the Staff Reports will you respond to?

A: I will address issues raised at pages 194-200 section XIV.B parts 1, 2, and 3 of Staff's Revenue Requirement Cost of Service and certain points of Staff's Rate Design And Class Cost-Of-Service report sponsored by Staff Expert/Witness Dana Eaves.

Q: Who was the Staff Expert/Witness for the portions of the Revenue Requirement Cost of Service report you will be addressing?

A: Staff's Revenue Requirement Cost of Service did not identify an Expert/Witness for section XIV.B parts 1, 2, and 3. Consequently when I am referring to that part of Staff's presentation I will cite "Staff" and when I refer to the Rate Design And Class Cost-Of-Service report sponsored by Staff Expert/Witness Dana Eaves I will cite Mr. Eaves.

Q: At page 198 Staff said "KCPL knows its coal costs because it has purchased a large percentage of its coal needed for generation for the next several years at a contracted price." What percentage of KCP&L's coal requirements for the next several years is under contract with a specified price?

A: Staff's statement is incorrect. As of March 31, 2015 about **[redacted]** of KCP&L's coal requirements for 2016 through 2019 are under contract. None of the expected requirement beyond 2017 were under contract. In my Direct testimony, which was prepared in September 2014, at page 22 line I said "As of June 30 [2014], about 70% of KCP&L's expected coal burn from 2015 through 2018 was <u>not</u> under contract." [emphasis added]

Q: Why are the years 2016 through 2019 relevant?

A: If this case results in a FAC, Section 386.266.4(3) requires a utility with a FAC to file a general rate case no later than four years after the effective date of the commission order implementing the FAC. It appears to me that it was the intent of the legislature that a FAC should be able to function for four years before needing a thorough reexamination. For this FAC that would be October 2015 through September 2019.

Q: At page 4 Ms. Mantle recommends certain modifications to KCP&L's proposed FAC. Do you have any concerns with Ms. Mantle's recommendations?

A: Yes. I have several concerns with Ms. Mantle's recommended modifications to KCP&L's proposed FAC but I will limit my discussion because some of those concerns are addressed by other witnesses. I will focus my discussion on how Ms. Mantle's modifications are not balanced. They are structured to exclude cost increases from the FAC while including potential cost decreases.

Q: How are Ms. Mantle's recommendations structured to exclude cost increases from the FAC while including potential cost decreases?

A: In item D (identified in her Direct Testimony at pages 4 and 30, and discussed in detail on pages 34-35) she says the FAC should only include costs or revenues that KCP&L is currently incurring or receiving. She proposes that the FAC should not include costs or revenues that the Company is not currently receiving and that have not been documented as expected. She then makes an exception to that overall exclusion of unknown future costs or revenues. Her exception is to include unknown and unidentified insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC. Such insurance recoveries, subrogation recoveries, and settlement proceeds would serve only to reduce Net Energy Costs.

Q: Are you advocating that the Commission reject Ms. Mantle's recommendation to include in the FAC unknown and unidentified insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC?

A: No. My recommendation is the Commission take a balanced approach with regard to what is in or out of the FAC. For example, if the Commission adopts Ms. Mantle's recommendation to include in the FAC unknown and unidentified insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues, then to be consistent it should also allow the inclusion of other unknown and unidentified fuel, purchased-power, power sales, transportation, and transmission costs and revenues.

Q: Do you feel limiting the costs that are included in the FAC is a detriment to customers?

A: Yes. The Company has an ongoing responsibility to incur prudent costs on behalf of its customers. Limiting items included in the FAC to predefined costs currently utilized by the Company would not encourage the Company to use new technologies or strategies that would benefit the customer when the associated costs are not included in the FAC. For example, at page 26 Mr. Brosch discusses the time when KCP&L successfully challenged a rail freight rate. If Ms. Mantle's philosophy were adopted where the FAC is limited to only predefined costs the millions of dollars benefit of the lower freight rates would flow through the FAC to customers but the Company would be left to pay the multi-million dollar expenditure that made those savings possible.

Q: Mr. Brosch and Mr. Eaves advocate excluding certain transmission costs from the Company's Net Energy Cost described by Mr. Rush and detailed in Schedule TMR-4. Are there issues with excluding all or part of the transmission costs from the Company's Net Energy Cost in the FAC?

A: Yes there are serious issues with excluding SPP's transmission charges from the Company's Net Energy Cost in the FAC. I will specifically address the Schedule 1-A and 11 charges because they were specifically identified for exclusion. The purpose of SPP's Schedule 1-A and 11 transmission charges discussed by Company witness Mr. John R. Carlson are to facilitate the efficient operation of the Integrated Marketplace ("IM"). The costs that those charges reflect were incurred for the purpose of lowering total power production costs, which benefit customers. No one has advocated excluding those cost savings that are achieved by participating in the SPP IM market and incurring the Schedule 1-A and 11 transmissions charges from the FAC. Because all of the savings that justify SPP's Schedule 1-A and 11 transmission charges will flow through the FAC it would be unfair and inconsistent to divorce the savings from the costs that made those savings possible. Such an exclusion could be a violation of Section 386.266.4(1)'s requirement that a FAC be reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity. A FAC that divorces production cost savings from the transmission costs that made those savings possible would by design impair the Company's opportunity to earn a fair return on equity.

Q: How would divorcing production cost savings from the transmission costs that made those savings possible impair the Company's opportunity to earn a fair return on equity?

A: Transmission congestion costs are the additional production costs resulting from the lack of transmission capacity. Those additional production costs are incurred when low-cost generation must be backed down and higher-cost generation must be ramped up to serve load. Transmission congestion cost is the marginal cost of that redispatch. Those marginal costs reflect the incremental fuel and fuel related costs of the higher-cost generation. In addition, if the Company's generation is backed down it also forgoes the potential revenue and margins from sales off the unit that is backed down.

Transmission congestion costs are an integral part of the price of electricity in the IM. In the IM KCP&L sells its generation to SPP at the generator's Locational Marginal Price ("LMP"). KCP&L buys the generation that serves its customers from SPP at the KCP&L load LMP. That is, the price KCP&L receives from SPP for the Company's generation is different than the price it pays SPP for serving its customers because the two transactions occur at different locations. The LMP value includes the cost of producing energy and the cost of its delivery. The cost of delivery includes transmission congestion costs and losses. LMPs are comprised of a Marginal Energy Component, Marginal Congestion Component, and Marginal Loss Component. The price KCP&L receives is the generator LMP and the price KCP&L pays is the load LMP. The Company cannot choose to pay or receive only selected portions of either LMP price.

These LMP's with their embedded transmission costs are foundational to the IM and both the economic value of the Company's generation and the cost of all energy used to serve the Company's customers. Even if the Company's generation is construed as serving its own customers, the Company will still pay the total amount of these transmission congestion costs and losses because the real transactions are priced at the LMP which include them. It is the reduction in these transmission congestion costs and losses that justify the transmission infrastructure build paid for by Schedule 11 charges. Even if the Company's generation is construed as serving its own customers as a means for justifying the removal of Schedule 1-A and 11 charges from the Company's proposed FAC while leaving any revenues and costs determined by LMPs in the FAC, this re-designed FAC will impair the Company's ability to earn a fair return on equity. Reduction in Net Energy Costs will no longer be matched with the cost incurred to achieve that reduction.

Q: Has KCP&L experienced a reduction in congestion costs from a SPP transmission project paid for through SPP's Schedule 11 charges?

A: Yes. KCP&L's Net Energy Costs have been reduced by transmission infrastructure that was paid for by Schedule 11 charges. For example, a new transmission line was recently installed between Iatan and the Nashua substation. This line went into service on April 16, 2015, and congestion between Iatan and the KCP&L and GMO load settlement locations immediately dropped.

Q: What benefits did KCP&L see with the addition of SPP's Iatan - Nashua project funded through SPP's Schedule 11 charges?

A: For the first half of April 2015 before the Iatan-Nashua line was energized on April 16^{th}, the average congestion cost in the day-ahead market between Iatan and KCP&L's load settlement location was \$7.39/MWh for on-peak hours and \$1.54/MWh for off-peak hours. After the line was energized the average congestion cost dropped to -$0.17/MWh for on-peak and to $1.33/MWh for off-peak hours. Those benefits are reflected in Accounts 447 and 555 as part of the LMP for electricity either sold or purchased.

In addition to those reductions in congestion costs, there is the benefit of more efficient operation of the Iatan units. There were many times prior to the activation of this new transmission line when the Iatan units' generation would be reduced or constrained to alleviate transmission system congestion. Constraining the units below their optimal operating levels put them at less efficient points on their heat rate curves. This will happen far less now that the new transmission line is in-service. Clearly, the savings that justify the transmission project and its cost are being seen in the reductions in production expense.

Q: **Are these transmission costs that Mr. Brosch and Mr. Eaves want excluded from the FAC integral to SPP's Integrated Marketplace?**

A: Yes. The transmission and the charges that pay for that transmission are a critical component of SPP's IM. SPP's IM is consistent with national energy policies being implemented by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. SPP's IM was implemented in response to those policies. Through the IM and the transmission that enables the IM, SPP is working to minimize the total cost of electricity within the region.

Q: **What is included in the total cost of electricity that SPP is striving to minimize?**

A: SPP's *Market Protocols* specify that each Resource's marginal system losses, congestion, and Energy costs are included in the least cost co-optimization I discussed earlier.[6] More

[6] *Market Protocols for SPP Integrated Marketplace*, Southwest Power Pool, Version 24, 2/12/2015, pp. 60 and 61.

specifically those costs include coal, coal transportation, emission allowances, environmental control reagents, fuel additives, natural gas, natural gas transportation, oil, oil transportation, nuclear fuel (nuclear fuel transportation costs are included in the cost of nuclear fuel), nuclear disposal fee (this was suspended in May 2014), and electricity transportation which is more commonly referred to as transmission. Within each of those elements are sub components. For example, coal transportation typically includes a fuel surcharge. One or more of the items may include hedging adjustments. All of the transportation elements have a cost for people and computers at other companies managing the transportation system and running the equipment.

Q: Has SPP been successful in reducing the total cost of producing and transmitting electricity?

A: Yes. In April 2015 SPP reported net savings of $210 million for the 12 months from April 2014 through March 2015.[7]

Q: Who gets the benefits of SPP's efforts to minimize the total cost of electricity?

A: Customers. Therefore, if KCP&L's proposed FAC becomes effective, its customers will receive the benefits because the Net Energy Cost as the Company has proposed it will match costs and benefits and will pass the net of those costs and benefits to customers.

Q: How does the Net Energy Cost in the Company's proposed FAC compare to the total cost of producing and transmitting electricity that SPP is endeavoring to minimize?

A: Schedule TMR-4 in Company witness, Tim Rush's testimony lists the following components of Net Energy Costs:

- Fuel costs;
- Emission costs;
- Purchased power costs;
- Transmission costs;
- Off-system sales revenue; and
- Renewable energy credit revenue.

The sum of those components is essentially the Company's portion of the total cost of producing and transmitting electricity that SPP is striving to minimize.

Q: Do you have any other issues with Mr. Brosch and Mr. Eaves' recommendation to exclude transmission costs from the Company's Net Energy Cost in the FAC?

A: Yes. Mr. Brosch's recommendation to exclude transmission from the FAC contradicts my understanding of a recent Missouri Court of Appeals decision[8]. As counsel has explained to me, the Missouri Court of Appeals concluded that the legislature intended the word "transportation" in RSMo 386.266.1 to encompass "transmission." Mr. Carlson discusses this more extensively in his Rebuttal testimony.

Q: How will these proposals to exclude some of the elements the Company has proposed in the FAC Net Energy Cost affect its customers and shareholders of the Company?

A: To the extent those elements are excluded from the FAC it would send the customers false price signals, by charging them less than the true cost and causing shareholders to pick up the tab.

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[7] *Integrated Marketplace: First Year Update*, Southwest Power Pool, presentation by Bruce Rew to Regional State Committee, April 27, 2015, slide 15.

[8] Union Electric Co. d/b/a Ameren Missouri, et al. v. Mo. Pub. Serv. Comm'n, 422 S.W.3d 358 (Mo. 2013).

Q: How would the proposals to exclude some of the elements of the Net Energy Cost from the FAC send customers false price signals?

A: Moving elements from the Net Energy Cost in the FAC to base rates would not allow recovery of legitimate costs incurred by the Company and customers would not see the current true cost of electricity. That means customers' choices would be based on false price signals.

Q: Why is it a problem to send customers false price signals?

A: Prices are signals between producers and customers. Prices are how producers and customers communicate so supply and demand are balanced. When prices are lower than the cost of producing and delivering a product to a customer that customer no longer has the ability to do their part of keeping production and demand in balance. For example, if the current true cost to produce and deliver electricity to a customer was 10 cents/kwh but through regulatory lag the customer saw a price of 8 cents/kwh, the customer would not choose to conserve. Instead, a rational customer would choose to continue using the 8 cents/kwh power, and the producer would suffer a 2 cents/kwh loss. In the non-regulated world the producer can either raise the price to recover its costs or it can stop production. In the regulated world, because the Company is obligated to serve, the Commission should ensure that the price charged by KCP&L in its FAC permits the recovery of the costs to provide that service.

Q: Can you give an example of when utilities were prevented from sending proper price signals to their customers?

A: The classic example is the California electricity crisis that began in 2000. A major component of that crisis was mandated reduction and freeze in the retail price of electricity. If the proper price signals had been sent to the consumers, they would have had the information necessary to avoid rolling blackouts and the financial destabilization that affected California electric utilities.[9]

Q: At page 197 Staff says KCP&L exercises control over the prices it pays for fuel and at page 25 Ms. Mantle says KCP&L has control over the contract prices it enters into and the timing of such purchases. How does that work in practice?

A: As I discussed in my Direct Testimony and as Staff and Ms. Mantle agree, KCP&L does not control the market. What we do have is a limited ability to make commitments. We can either agree to pay the price demanded by a seller or not pay that price. If we choose to not pay that price, we do not get the fuel or transportation service the seller was willing to offer at that price. If we reject so many offers that we do not have sufficient fuel to run our plants, we will not be able to meet our obligations to offer energy to SPP's IM. Nor will we have revenue from those lost sales to SPP to offset the energy purchases from SPP necessary to serve our load. That is, even our ability to choose whether or when to enter a fuel-related contract is limited.

Q: You said that if you reject too many offers, you would not be able to meet your obligation to offer energy to the SPP's IM. Doesn't the fuel KCP&L buys serve KCP&L's retail customers?

A: Under the IM, the electricity generated from the fuel purchased by KCP&L is sold to SPP. SPP aggregates the power it purchases from the various market participants and then sells power to KCP&L from that aggregated pool. KCP&L's generation no longer directly serves its load.

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[9] *Causes and Lessons of the California Electricity Crisis*, Congressional Budget Office, Sept. 2001.

Michael L. Brosch – Midwest Energy Consumers' Group

Q: Does MECG witness Brosch support adoption of an FAC for KCP&L?

A: No. An argument that runs through Mr. Brosch's rate design Direct Testimony can be paraphrased as follows: Because the Company has prudently and effectively managed its Net Energy Costs, it should continue to operate with a fixed rate allowance for fuel and purchased power-related costs that are so large that even small percentage changes materially affect KCP&L's earnings.

Q: In Mr. Brosch's evaluation of coal price risk on page 17 (Rate Design Direct Testimony) he looks at a hypothetical 10 percent in market price of coal and presents that as the Company's exposure to coal price fluctuations. Please explain the relevance of that analysis to this case.

A: The hypothetical 10 percent move in a commodity price is a standard analysis we perform as part of our SEC reporting. It is typically performed in January for that calendar year.

Q: Are there any particular problems with Mr. Brosch's use of that hypothetical 10 percent market move in this case?

A: Yes. There are two significant problems with Mr. Brosch's assertions based on the hypothetical 10 percent market move analysis. First, the analysis Mr. Brosch cites was performed in January 2015 to evaluate the Company's exposure to coal prices in calendar year 2015. It makes no assessment of the likelihood of a 10 percent market move. To apply this hypothetical price move correctly, one must combine it with a probabilistic assessment of market price movement. Mr. Brosch did not do that. Second, the hypothetical movement analysis Mr. Brosch used does not look beyond December 2015.

That means it has little to no relevance to the proposed FAC whose first accumulation period begins October 1, 2015. The period of risk that must be considered in evaluating the proposed FAC is October 1, 2015 through September 30, 2019.

Q: At page 19 Mr. Brosch (Rate Design Direct Testimony) compares KCP&L's exposure to fluctuations in Net Energy Costs with Union Electric Company d/b/a Ameren Missouri ("Ameren"), the Empire District Electric Company ("Empire") and KCP&L Greater Missouri Operations ("GMO") by looking at the percentage of each company's total Missouri jurisdictional revenue requirement represented by Net Energy Costs in recent filings before this Commission. Have you done any similar analyses?

A: Yes. I calculated net energy costs for the utilities included in the Company's proxy group identified by Company witness Robert H. Hevert.

Q: How did you calculate net energy costs for those utilities?

A: Generally I followed the model for Net Energy Costs laid out for the Company's proposed FAC in Schedule TMR-4. That is, using SNL's database of publicly available FERC Form 1 data, I calculated net energy costs as the sum of expenses charged to Accounts 501, 509, 518, 547, 555, 561.4, 561.8, 565, and 575.7, less the revenues recorded in Accounts 447 and 456.1. Because the majority of the costs in Account 928 are not included in our proposed FAC, I excluded it from my from net energy cost calculation. To help distinguish my calculation of net energy costs from the calculation in the proposed tariff, I will use the title capitalization of Net Energy Costs when referring to the proposed FAC.

Q: Do others use the FERC Form 1 data for comparing utilities' fuel and power costs?

A: Yes. For example, it was a component of a study regarding electric utility automatic adjustment clauses prepared for Edison Electric Institute by the Brattle Group.[10]

Q: How does your calculation of net energy cost compare to the more specific calculation described in Mr. Rush's Schedule TMR-4?

A: It is quite close. The Company's proposed FAC described in Schedule TMR-4 excludes certain cost items such as unit train depreciation which is not discernible at the FERC Form 1 level. My calculation of net energy cost for KCP&L was within 10% of the Company's Net Energy Cost using the greater level of detail specified in Schedule TMR-4 for 2014.

Q: Did you compare the net energy costs for each of those companies to their Missouri jurisdictional revenue requirement?

A: No. Most of the utilities in the proxy group do not operate in Missouri so I compared their net energy costs to their total utility operating expense.

Q: What years did you compare?

A: My analysis started with 2006. Effective January 1, 2006, FERC changed its reporting requirements and its USOA to better identify various Regional Transmission Organization costs. Since our FAC uses those new accounts, I started my analysis with 2006 data.

[10] *Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations*, Frank Graves, Philip Hanser, Greg Basheda, The Brattle Group, November 2006.

Q: What did you discover by comparing the net energy costs for those companies with their total utility operating expense?

A: One, KCP&L's net energy costs were more volatile than 13 of the 14 companies in Mr. Hevert's proxy group. Two, the ratio of net energy costs to total operating expense changes over time. Three, since 2011 KCP&L's ratio of net energy costs to total operating expense has exceeded the weighted average for Mr. Hevert's proxy group.

Q: If a company's ratio of net energy costs to total operating expense changes over time, does that raise any concerns about Mr. Brosch's analysis?

A: Yes. Mr. Brosch compared ratios from different time periods. As the following chart shows, of the cases cited by Mr. Brosch this case is the only one that reaches into 2015. The others are 2014 and 2012.

Company **Case No.**	**Filed**	**Test Year** **12 months ending**	**Trued-up Through**
GMO ER-2012-0175	February 27, 2012	September 30, 2011 projected through August 31, 2012	March 31, 2012
Ameren ER-2014-0258	July 3, 2014	March 31, 2014	December 31, 2014
The Empire District Electric ER-2014-0351	August 29, 2014	April 30, 2014	December 31, 2014
KCP&L ER-2014-0370	October 30, 2014	March 31, 2014	April 30, 2015[11]

As the chart above shows, while Ameren and Empire cases may be comparable with one another, the GMO and KCP&L cases are not comparable with each other nor are they comparable with the Ameren and Empire cases. KCP&L's case was filed based on fuel prices projected for April 2015. The GMO case was filed based on fuel prices projected for March 2012. There was more than 3 years difference between GMO's and KCP&L's fuel prices. Ameren and Empire did not look past the end of 2014. Crossing from December 31 to January 1 tends to have a significant impact on fuel and freight prices because many contracts expire at the end of a year. Many fuel or freight contracts change prices annually or quarterly or monthly. When you go from December 31 to January 1 you get all of those changes. Mr. Brosch's analysis is flawed because it does not compare like items.

Q: At page 194 Staff claims KCP&L has not demonstrated that fuel, purchased power and transmission costs are volatile. What did you find about the volatility of your net energy costs?

A: My analysis showed that KCP&L's net energy costs for 2006-2013 were significantly more volatile than Missouri's three other electric utilities which all have FACs. Moreover, the volatility of KCP&L's net energy costs was greater than 13 of the 14 companies in Mr. Hevert's proxy group.

Q: At pages 19-20 Mr. Brosch (Rate Design Direct Testimony) claims that KCP&L's coal costs have remained stable in recent history. Do you have any issues with Mr. Brosch's representation of KCP&L's coal costs?

A: Yes. I have two significant issues with Mr. Brosch's representation of KCP&L's coal costs. The first is the time horizon he chose to look at. Apparent stability can really just be a question of how long of a time period you look at. Coal freight rates generally change quarterly for changes in railroad costs and monthly for changes in fuel costs. In other markets such as natural gas and coal, the price can change with each transaction.

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[11] Since the preparation of Mr. Klote's Direct Testimony, the true-up period has changed to May 31, 2015.

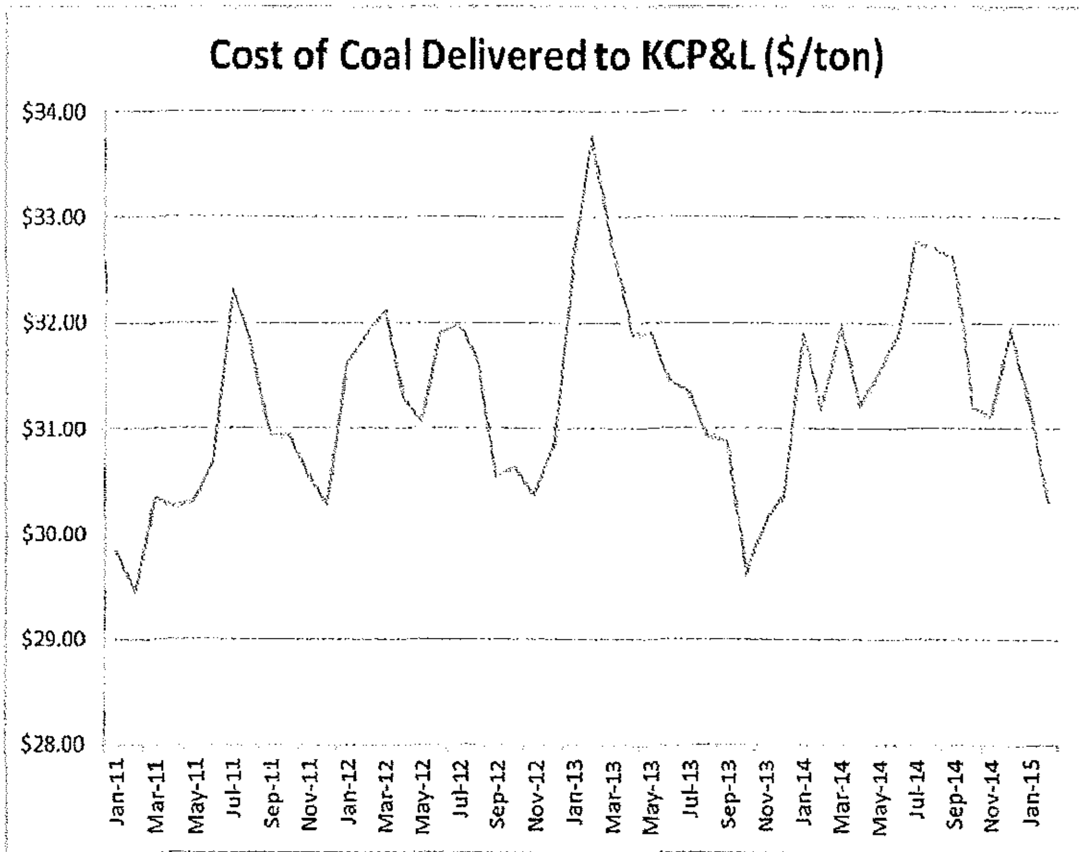
Prices that are fixed by contract may be stable for some period defined by the contract. Currently, it is typical for a fixed price coal contract to stabilize the commodity price for a year or quarter. Indexed coal contracts tend to change prices quarterly. More time elapsed between the filing of the Company's last rate case[12] and this case than is reflected in Mr. Brosch's "recent history of just 2 years."

My second issue with Mr. Brosch's representation of KCP&L's coal costs is that he uses our highest price but lowest volume bituminous coal to set the scale for his chart. That masks the volatility of our lower priced but much larger volumes of subbituminous Powder River Basin ("PRB") coal.

Q: Do you have a chart that shows the volatility in the delivered cost of coal purchased by KCP&L?

A: Yes. The graph below shows a couple more years of history than Mr. Brosch did, and shows the average price for all of KCP&L's coal receipts. It also limits the scale so the chart shows primarily the range over which the delivered cost moves. It shows that KCP&L's delivered cost of coal can easily swing up 10% and down 10% within 12 months.

[12] Case No. ER-2012-0174 was filed Feb. 27, 2012.



Q: At page 21 Mr. Brosch (Rate Design Direct Testimony) contends that KCPL's rail freight contracts have stable pricing and dampen the delivered cost of coal. Does KCP&L's weighted average monthly freight cost exhibit volatility?

A: Yes. KCP&L's weighted average freight rate has had some significant price swings over the past few years. For example, from February 2013 to October 2013, it dropped 15%. By July 2014 it had climbed 15% but then it started dropping again. Given that KCP&L spends about **[redacted]** million per year on rail freight, a 15% move is a swing of almost **[redacted]** million. KCP&L's weighted average monthly f.o.b. price of coal and its weighted average monthly rail freight have about a 65% correlation. That means about two-thirds of the time, the prices are moving together and not offsetting one another.

Q: Also at page 21 of his Rate Design Direct Testimony Mr. Brosch contends that the Company is expecting "a relatively stable pricing environment for its coal fuels in the near future." Is that an accurate representation of the Company's expectations regarding the prices it may pay for coal during the expected term of the proposed FAC?

A: No. Mr. Brosch's statements are not an accurate representation of the Company's projections of the coal prices it expects to pay. Mr. Brosch drew his data from MECG Data Request No. 2-2, which he attached to his testimony as Schedule MLB-14. MECG 2-2 item b asked "For each coal contract ... that is intended to provide stabilizing pricing" and item c asked for "forward contracts [that] are expected to be used to stabilize pricing". Then Mr. Brosch only presented the price expectations for the current year and the **[redacted]** of next year's requirements that are under contract. The majority of those tons will be delivered before rates established from this case are effective. Examining more relevant data than Mr. Brosch presented shows a quite different situation.

Q: What does KCP&L expect regarding the prices it may pay for coal over the next four years?

A: KCP&L's April forecast of the PRB prices it expects to pay for the **[redacted]** of its expected coal burn over the next four years that is not under contract ranges from **[redacted]** per ton.

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Q: **At page 22 Mr. Brosch (Rate Design Direct) claims to have identified some "serious flaws" in your analysis showing that KCP&L is exposed to **[redacted]** million in coal price risk. Was your estimate of the risk exposure exaggerated, as claimed by Mr. Brosch?**

A: No but even if we take Mr. Brosch's "cut it in half" approach to my calculation you still have well over **[redacted]** million of coal price risk exposure. That is a substantial sum of money in almost any context, but it is particularly meaningful in comparison to KCP&L's 2014 net operating income (i.e., earnings available to compensate equity shareholders) of $162 million.

Q: **Mr. Brosch also claims that your analysis was flawed because you looked at four years. Why did you look at four years?**

A: Section 386.266.4(3) requires a utility with a FAC to file a general rate case no later than four years after the effective date of the commission order implementing the FAC. I assumed that it was the intent of the legislature that an FAC should be able to function for four years before needing a thorough reexamination.

Q: **Are there any serious flaws with Mr. Brosch's revised calculation of annual exposure to coal price fluctuations?**

A: Yes. Mr. Brosch makes two flawed assumptions. First he assumed that coal prices and uncertainty regarding coal prices remains unchanged from one year to the next. Throughout my testimony I have presented multiple graphs which show that coal prices change over time. An examination of those schedules also shows that the volatility or uncertainty in coal prices changes over time. The other flawed assumption in Mr. Brosch's analysis is that he only looks at one year. It takes almost one year to process a rate case. The **[redacted]** million coal price risk exposure Mr. Brosch presents is about the amount of coal price risk from the filing of a rate case until rates are effective. It is not a reasonable representation of the risk the Company faces between rate cases, unless the Company would file a new rate case every year.

Q: Mr. Brosch also contends at page 23 of his Rate Design Direct Testimony that because the Company's coal hedging program dampens the volatility of fuel prices in the short-term there is no need for an FAC. Do you agree?

A: No. I have testified in many cases how this Commission has consistently encouraged and supported prudent hedging of market risk. Moreover, 4 CSR 240-3.161(2)(K), Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements, requires that a "complete explanation of any rate volatility mitigation features designed in the proposed RAM" be included in a filing requesting a FAC. It seems that Mr. Brosch is really arguing that because the Company has prudently and effectively managed its Net Energy Costs, it should be denied a FAC and penalized with the continuation of regulatory lag on some of its largest and most volatile uncontrollable costs.

Q: Mr. Brosch has attacked various elements of Net Energy Costs of his Rate Design Direct Testimony, arguing they are insufficiently volatile to warrant an FAC and could be addressed in traditional rate cases. At page 29 he addresses nuclear fuel expense. What would be the impact if the Commission were to exclude nuclear fuel costs from the FAC?

A: If the expense is as stable as Mr. Brosch contends, excluding it from the FAC would not reduce the customer's bill, but it could result in an unnecessarily higher bill.

Q: How could Mr. Brosch's proposal cause customers' bills to be unnecessarily high?

A: Under the IM, KCP&L purchases all of the energy used to serve its load from SPP. KCP&L sells all of the energy generated by its plants to SPP. The revenues from KCP&L's generator sales, including Wolf Creek, to SPP offset the cost of energy purchased from SPP. If Wolf Creek experienced a forced outage, there would not be revenue associated with its generation to offset the cost of energy purchased from SPP. Consequently the cost of purchased power included in the FAC would be higher. Under Mr. Brosch's proposal the customer would still be charged for the cost of Wolf Creek's fuel even though the plant was in a forced outage and the customer would be charged for the higher level of purchased power. It would be more consistent and predictable to keep the relatively stable costs of nuclear fuel in the FAC.

Q: At page 31 Mr. Brosch (Rate Design Testimony) contends that natural gas and oil costs are not large enough to merit FAC treatment. Do you agree?

A: No. There are multiple issues with Mr. Brosch's position, but generally he fails to recognize there is significant volume risk with natural gas and oil.

Q: Why is there significant volume risk with natural gas and oil?

A: Projection models frequently underestimate the actual quantity of natural gas required. This is especially true for the normalized models used to determine fuel expense in a general rate case. For example, in the Company's last case, File No. ER-2012-0174, Staff's true-up analysis determined that the Company would burn 903,972 MMBtus of natural gas in its gas-fired units and 0 MMBtus of oil at Northeast. The table below shows that during 2012-2014 KCP&L burned more than triple that amount of natural gas. Every MMBtu of oil burned at Northeast was more than that projected.

Fuel	In Cost of Service	2012 Actual	2013 Actual	2014 Actual
Natural Gas	903,972	2,916,741	1,828,129	1,387,603
Oil	0	23,264	19,147	35,242

Q: Are there any other flaws in Mr. Brosch's position that natural gas and oil do not merit fuel adjustment clause treatment?

A: Yes. There are volume risk issue and price risk issues with SPP's IM and SPP's centralized dispatch of units within its consolidated balancing authority. Because SPP has more units available for dispatch, more load to serve, and different transmission issues than KCP&L, it dispatches the Company's units differently than KCP&L did when it was a standalone balancing authority. That creates more uncertainty regarding how the units are operated in both the level of use and timing of use. Prior to implementation of the IM, KCP&L could for the most part predict if it would need natural gas generation for the next day. Under the IM, we typically receive dispatch instruction for our natural gas units after the "next day" gas market has closed. That means we do not know if our gas units will need fuel until the day they need the fuel leaving us to buy "same day" gas. Anecdotal evidence suggests unpublished "same day" gas prices are more volatile than published "next day" prices.

Q: Mr. Brosch appears to argue that any element of Net Energy Costs can be excluded from the FAC. What would happen if the FAC does not include all of the elements of Net Energy Cost in the Company's proposed FAC?

A: Such an FAC would be an unbalanced adjustment mechanism and would likely fail to accomplish the goals sought to be achieved by Section 386.266. There are offsets between some of the elements in the Company's proposed FAC. For example, the market price for natural gas drives both the cost of natural gas purchased by the Company for use as fuel and the price of electricity the Company sells to SPP. In a rising natural gas market, the cost of natural gas for fuel would increase, but that increase would likely be offset by higher margins from off-system electricity sales. At other times there may a compounding effect rather than an offset. To some extent PRB coal prices are influenced by the market price for natural gas. In that case, a rise in natural gas prices could raise coal prices and, contrary to Mr. Brosch's assertion, even with our portfolio of coal contracts in place, KCP&L still has exposure to the market price of coal because some of those contracted volumes are repriced at prevailing market prices every month or quarter. Even the so-called fixed price contracts typically adjust prices annually.

Q: At page 34 Mr. Brosch (Rate Design Direct Testimony) asserts that the volatility in the market prices of fossil fuels presented in your Schedules WEB-3 and WEB-4 do not reflect the volatility KCP&L actually experiences. Why should the Commission consider the historical fluctuations in daily market prices for natural gas, oil, and coal shown in your Schedule WEB-3?

A: Historical fluctuations should be considered because they affect the Company's procurement decisions and the prices it pays for these fuels. Regarding natural gas, KCP&L makes purchases on the day it needs the gas. After the Company receives a dispatch instruction for one of its natural gas units, we solicit offers for natural gas. This "same day" gas is subject to intra-day volatility, in addition to the daily volatility shown by the daily settlement prices in my Schedule WEB-3.

We buy oil much like a consumer buys gas for a car. That is, when the tank is low, we refill it. Like with a car, there are times when you have a little flexibility about when to refill your tank and there are times when you do not have such freedom. In either case, you do not know whether the price will go up or down after you make your purchase. Even if you did, you may not have the flexibility to wait for the price to go down. Both price and timing are a function of the movement in market prices.

Coal is somewhat like my oil example above. As a coal buyer, we face the daily volatility shown in my Schedule WEB-3. It is after we sign a contract that fixes the price, we mitigate that volatility for our customers when those purchases move through our inventory. Where we sit today the Company faces the market price volatility shown in my various Schedules.

Q: Which is more relevant to the Commission's consideration of a utility's application for a FAC: fluctuations in fuel and energy market prices, or fluctuations in a company's fuel expense?

A: They both have relevance. The fuel and energy market fluctuations show the risks that the company faces. The fluctuations in a utility's expenses show how a company is mitigating that fluctuation. Given the FAC mechanics spelled out in 4 CSR 240-20.090, the volatility a company faces will be dampened by the FAC mechanism.

Q: At page 53 Mr. Brosch (Rate Design Direct) advocates that any regulatory tracking mechanism be limited to only KCP&L's off-system sales margin. What would happen if Mr. Brosch's version of "piecemeal ratemaking" was applied to the FAC?

A: Adoption of such a proposal would increase KCP&L's financial risks. Within the Company's proposed FAC various revenues and costs are matched. For example, SPP's Winter 2015 State of the Market Report noted that "although many factors determine electricity prices, gas cost is the primary driver for the trend in electricity prices over time".[13] Consequently natural gas prices drive both the Company's natural gas expense and its off-system sales margin. That means higher natural gas costs are offset by higher off-system sales margins. To "cherry pick" off-system sales margins from the various elements in the Company's proposed FAC would create risk for the Company and violate Section 386.266.4(1)'s requirement that a FAC be reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity.

Q: Mr. Eaves recommended deleting the term "accessorial charges" from the proposed FAC tariff. What are those charges and why are they in the proposed FAC?

A: Accessorial charges are a necessary part of transporting coal by rail. They include switching, stripe alignment, release and pick-up of locomotive power. Rather than list each one of the various accessorial charges delineated in the various railroad accessorial tariffs or the costs we incur to satisfy accessorial tariff requirements such as applying surfactants or topper agents, we elected to use the term "accessorial charges" to reference that category of costs. The Company does not have unique account numbers nor does it have unique resource code for these costs. To specifically exclude them would increase the administrative and audit burden of the FAC.

Q: Mr. Eaves also recommended the exclusion of costs associated with KCP&L's cross-hedging policy. Are there any issues with excluding the costs associated with KCP&L's cross-hedging policy?

A: Cross-hedges are the best means for hedging power purchases or sales. If the costs of cross-hedging are excluded from the FAC, the Company will not hedge power purchases or sales for the benefit of its customers.

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[13] *State of the Market Report Winter 2015*, SPP Market Monitoring Unit, March 24, 2015, p. 2

Q: Without any specific discussion in the Report, Mr. Eaves struck various other costs from FERC Account 501 in the proposed FAC tariff in his Schedule DEE-1. Are there any issues with those modifications?

A: Yes. Striking broker commissions and fees is problematic. We pay broker commissions and fees on some of the coal we purchase. Typically those charges are embedded in the price we pay for that coal. While we may know what the broker's typical fee is, we typically do not see it on an invoice from the broker.

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 WILLIAM EDWARD BLUNK

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

William Edward Blunk, appearing before me, affirms and states:

1. My name is William Edward Blunk. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Generation Planning Manager.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Kansas City Power & Light Company consisting of thirty-five (35) 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 affirm and state 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.

William Edward Blunk

Subscribed and affirmed before me this 7th day of May, 2015.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2019

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2019
Commission Number: 14391200