Exhibit No.:	
Issue(s):	Fuel Adjustment Clause; Off-System Sales
Witness:	Andrew Meyer
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2016-0179
Date Testimony Prepared:	January 20, 2017

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

REBUTTAL TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January, 2017

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

ANDREW MEYER

Q. Please state your name and business address.

A. Andrew Meyer, 1901 Chouteau Avenue, St. Louis, MO 63103.

Q. Are you the same Andrew Meyer that filed direct testimony in this proceeding?

A. Yes I am.

I. <u>PURPOSE AND SUMMARY</u>

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address the Office of the Public Counsel's ("OPC") arguments regarding the inclusion of purchased power and transportation costs in Ameren Missouri's fuel adjustment clause ("FAC"), which are sponsored by OPC witness Lena Mantle. Specifically, I explain why OPC's attempt to redefine the terms "purchased power" and "transportation" inappropriately excludes many components that are well-understood by regulators and the industry to make up the cost of purchased power and associated transportation.

I will also address the calculation of the bilateral transaction margin adjustment to off-system sales performed by Staff Witness Erin Maloney.

Q. **Please summarize your main conclusions regarding Ms. Mantle's testimony.**

A. Purchased power and associated transmission costs consist of a variety of components, including many that OPC is attempting to improperly exclude from the

FAC, as confirmed by the understanding of those terms in the industry and by regulators, including the Federal Energy Regulatory Commission ("FERC"), this Commission's Staff, and this Commission itself. These components of purchased power, which were once bundled together as a single product, are now visible through a combination of the regional transmission organization ("RTO") market settlement structure and the utility's managerial accounting decisions to record a higher level of detail than any rule requires. OPC is simply picking and choosing components that it favors, while ignoring others. OPC is also attempting to exclude legitimate transmission costs from the FAC by recycling arguments it has already (twice) lost.

OPC's attempt to ignore many key cost components that comprise the total cost of purchased power is directly at odds with its recommendation that all components that make up total off-system sales revenues ("OSSR") should be included in the FAC.[1] Consequently, OPC's proposal, if it were to be adopted, would create a mismatch because while all components of OSSR would remain in the FAC, there would be components of purchased power costs that those OSSR revenues offset that would improperly be excluded. The Commission should reject the separation of costs and revenue components from other components which offset their value or are otherwise inextricably tied together.

OPC's proposal would also exclude from the FAC certain components of purchased power which offset *other* purchased power components. Those offsets provide a hedge for cost exposure *for customers*. All these components make up the total cost of purchased power and, just as revenues that are part of OSSR should not be separated

[1] All components of OSSR that make up total OSSR revenues have been included in Ameren Missouri's FAC from its inception in 2009.

from purchased power components that they offset, components of purchased power that offset other components of purchased power should similarly not be separated.

Q. Please summarize your main conclusions regarding Ms. Malony's testimony.

A. I recommend that the bilateral transaction margin adjustment be calculated using actual bilateral sale and purchase transaction prices and volumes and the corresponding actual spot market prices. I recommend that the calculation utilize 36 months of actual data ending December 31, 2016, adjusted for the Polar Vortex period of January 2014-March 2014.

II. OPC'S RECOMMENDATIONS ARE BASED ON AN INCORRECT INTERPRETATION OF WHAT CONSTITUTES PURCHASED POWER AND TRANSMISSION COSTS

Q. Why are OPC's recommendations based on an incorrect interpretation of what constitutes purchased power and transmission costs?

A. Section 386.266, which is commonly referred to as the "FAC statute," authorizes the Commission to approve FACs that allow rate adjustments based on changes in "prudently incurred fuel and purchased power costs, including transportation." The questions then are what are fuel costs, what are purchased power costs, and what are the associated transportation costs?[2] Ameren Missouri witness Lynn M. Barnes will address the fuel and associated transportation costs issue in her rebuttal testimony filed in this docket. At its core, OPC's position, based on (apparently) nothing more than Ms. Mantle's opinion, is that the Commission should redefine what "purchased power" and

[2] In this context, I will refer to "transportation" costs as "transmission" costs. It is my understanding that the Missouri courts have confirmed that in the context of the FAC statute, "transportation" encompasses transmission.

"transmission" costs are. More specifically, OPC argues that only the charges paid by Ameren Missouri for a very few components of purchased power (some components of energy and capacity costs) should be included in the costs of purchased power included in the FAC. OPC also wants to also severely limit the definition of "transmission." With respect to purchased power, while charges for energy and capacity are indeed two of the components that make up the cost of purchased power, there are many others (including some components of energy and capacity themselves) that OPC either ignores or fails to understand.[3] With respect to transmission costs, point-to-point ("PTP") and network integration transmission services ("NITS") charges are also two components of total transmission costs, but again, there are many others that OPC improperly ignores or mischaracterizes.

A. Purchased Power Costs

Q. Earlier you seemed to suggest that what constitutes purchased power and transportation before and after the establishment of the Midcontinent Independent System Operator, Inc. ("MISO") market remains the same. Please explain.

A. Prior to the establishment of the MISO market, we operated in a purely bilateral market. We bought and sold with other utilities, as well as power marketers. Purchased power was a bundled product. The bundled product was priced in a manner to cover everything needed up to the point of delivery. For example, if a marketer was selling to Ameren Missouri, they had to make sure that the price they charged covered their incremental costs – not only production cost, but also transmission service, ancillary

[3] As discussed further below, OPC's recommendation regarding including "energy" and "capacity" is at best, vague.

services, losses, risk premiums related to delivery risk (should the utility's transmission service be curtailed), or loss of resources, etc. The same was true for independent power producers, non-asset owning power marketers, and other utilities selling to Ameren Missouri. Sellers priced their products to cover their costs plus an expectation of profit. From Ameren Missouri's perspective, however, all we saw was the total cost of the purchased power: X megawatt-hours ("MWh") at $Y/MWh. We did not see a list of all the components that made up that purchased power, with individual line item charges. These bundled bilateral transactions continue to exist as an alternative to purchasing power from the MISO market.

RTO energy and ancillary service markets, including MISO's, were established to foster wholesale competition and contribute to improved system reliability. They were designed in a manner which promoted a more efficient use of resources. Later in my testimony I will discuss the concept of a co-optimized market and provide an example which illustrates how market participants (and their customers) benefit from such efficiencies.

As a result of this market design, the variety of cost components that used to be bundled together as charges for purchased power are now disaggregated. Buyers acquiring purchased power in the MISO market can now see the individual components of purchased power rather than simply seeing the bundled cost. The various charge and revenue types used in MISO settlements are themselves a byproduct of the more efficient market design.

This does not mean, however, that the components which were formerly bundled as part of overall purchased power costs have now lost their character as a component of purchased power costs. The nature of a component of purchased power is not changed just because someone put a different label on it for settlement purposes.

Q. You also mentioned that the components of purchased power costs are more visible as a result of managerial accounting decisions. Please explain.

A. Utilities are not required to utilize the level of detail in their accounting records that we actually do. There are a wide range of reasons for why an individual sub-account, resource type or activity code may be developed, including a desire to monitor a particular sub-component, greater transparency in reporting, ease of data retrieval, etc. These additional levels of detail provide greater information regarding the sub-components of fuel, purchased power and transportation, but they don't lose their character as part of the overall cost of those items just because the utility elects to break them out in into managerial accounting codes created at the utility's discretion.

Q. Does FERC, which exercises primary jurisdiction over the wholesale power markets, provide guidance as to what components make up the cost of purchased power?

A. Yes. The FERC Uniform System of Accounts ("USOA"), which Missouri utilities, including Ameren Missouri, must follow per this Commission's rules (4 CSR 240-20.030), provides a definition of each of the accounts included in the USOA. One such definition is for Account 555, titled "Purchased Power," as follows:

> *This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. Distinct purchases and sales shall not be*

> *recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.*

FERC recognizes that purchased power costs are made up of more than just the charges incurred by a utility for energy or capacity. While the definition does not list all the purchased power cost components (since the advent of RTOs, these are now broken-out in greater detail on RTO settlement statements), all those components make up the total cost of purchased power. As discussed further below, it is obvious that FERC itself recognizes that all these components are part of purchased power costs as well.

Q. Do you have any evidence to support your contention that those components make up the total cost of purchased power?

A. Yes. FERC recently completed a detailed audit of Ameren Missouri's compliance with the USOA (FERC Docket No. FA12-2-000). The audit covered a seven-year period, January 1, 2008 through December 31, 2014. All the components that make up the total cost of purchased power that are included in Ameren Missouri's FAC today are recorded in Account 555.[4] The Audit Report issued March 27, 2005 *did not contain a single finding that asserted that Ameren Missouri had improperly recorded any expenses in Account 555* – including those which OPC now wants the Commission to believe should not be viewed by this Commission as components of purchased power costs. FERC would not accept the recording of costs to Account 555 if those costs were not proper components of purchased power costs.

Q. Is there other evidence that these costs should be included as components of purchased power costs?

[4] All these components have been included in purchased power costs in Ameren Missouri's FAC since its inception in 2009.

A. Yes. FERC requires public utilities to make a yearly FERC Form 1 filing. Similarly, this Commission requires the filing of an Annual Report, which consists of part of that same FERC Form 1 filing. The purchased power costs included in those filings consist of far more than simply capacity and energy and, in fact, expressly call out many non-energy and non-capacity purchased power components, including Auction Revenue Rights ("ARR"), Inadvertent Energy, Energy Losses, Revenue Neutrality Uplift ("RNU"), Revenue Sufficiency Guarantees ("RSG"), Financial Transmission Rights ("FTR"), Ancillary Regulation, Ancillary Spinning and Ancillary Supplemental. I am unaware of any challenge by FERC, this Commission, the Staff, OPC or any other entity to the accuracy of Ameren Missouri's FERC Form 1 or Commission Annual Report filings.

Q. Has the Staff taken actions that suggest that it recognizes that there are far more components of purchased power than just energy and capacity?

A. Yes. Staff's workpapers in Ameren Missouri's general rate proceedings routinely reflect the Staff's inclusion of components of fuel, purchased power and transmission costs in the Staff's calculated values for fuel, purchased power and transmission costs which OPC would now have the Commission believe are not or should not be components of fuel, purchased power or transmission costs and thus should be excluded from the FAC. This includes numerous components of purchased power costs that OPC seeks to exclude, including components for RSG, RNU, congestion, losses, ARR, FTR, inadvertent, and a variety of ancillary service charges.

It would be illogical for Staff to treat all these charges as components of total purchased power (or transmission, as the case may be) costs, and use them to set the net base energy costs that set the base in Ameren Missouri's FAC, if those components were not properly a part of total purchased power and transmission costs.

Q. Please state your understanding of what purchased power costs would be included in the FAC if OPC's proposal were adopted.

A. Ms. Mantle's testimony on page 7, l. 8-11 states "OPC's recommended FAC limits purchased power costs to the cost of energy from long-term bilateral contracts, capacity charges from bilateral contracts that change annually or more frequently, and capacity and energy purchased through RTO markets to meet native load or to make off-system sales."

Q. Can one tell from Ms. Mantle's direct testimony how she is defining "energy purchased through RTO markets"?

A. No. Her testimony is vague. I would note that in quite similar direct testimony filed in File No. ER-2016-0285, Ms. Mantle was more specific. It is my assumption, therefore, that she is taking the same position in this case as she took in that case regarding what constitutes "energy" and "capacity" costs. If this assumption is correct, Ms. Mantle seeks to exclude a large number of legitimate purchased power components that have always been included in Ameren Missouri's FAC because purchased power consists of far more than just energy and capacity, as I believe she defines those terms.

Q. Was Ms. Mantle involved in issues regarding the FAC when it was first approved for Ameren Missouri in 2009?

A. Yes. According to her supplemental direct testimony in File No. ER-2010-0036 (page 2 lines 15-16), Ms. Mantle indicates that she helped draft the FAC tariff approved in that case.

Q. Did that tariff include more than just the two components of purchased power, as OPC apparently defines those components for purposes of this case?

A. Yes, significantly more.

Q. Are you aware of any component of purchased power OPC now seeks to exclude that the Staff has argued does not belong in Ameren Missouri's FAC?

A. No. I am not aware that Staff has sought to exclude any component of purchased power from our FAC, including when Ms. Mantle was the Staff's FAC witness.

Q. Aside from the foregoing, is there other evidence that purchased power costs within the meaning of the FAC statute are not limited to only the two components favored by OPC – capacity and energy - as OPC defines those terms?

A. Yes. The first, and most obvious, is that the Commission itself acknowledged the existence of a multitude of components comprising purchased power costs when it: approved Ameren Missouri's FAC tariffs in the Company's five prior general rate proceedings; issued approval orders in all five of the Ameren Missouri's FAC prudence review proceedings; and approved 22 of Ameren Missouri's FAC rate adjustment filings. All of these proceedings pertained to FACs that include as purchased power costs the very components that OPC now seeks to exclude. In addition, Ameren

Missouri has filed an FAC monthly report in every month for the past nearly eight years containing significant detail on all of these components.

Q. Do you have any other observations about OPC's attempt to redefine purchased power costs?

A. Yes. OPC witness Mantle states that the FAC statute "does not mention fuel adders, fuel handling, contractor costs, spinning reserve costs, startup costs, hedging costs, and a myriad of other costs and revenues." Mantle Direct, p. 7, l. 2-5. The point she is apparently attempting to make is that since these components are not explicitly listed, they should be excluded from the FAC. But neither "energy" nor "capacity" are listed in the statute either. Simply put, the General Assembly obviously chose not to list all of the individual components of purchased power (and fuel, and transmission) in the statute, but the failure to list a component does not mean that the component is not a part of purchased power costs.

The bottom line is that the Commission and its Staff, and the utilities that operate in the relevant markets, have had it right all along. OPC's improper attempt to redefine the components covered by the FAC should be rejected.

B. Transmission Costs

Q. What is the basis for Ms. Mantle's claim that the only components of transmission that should be included in the FAC are those categorized as point-to-point or network integration transmission service?

A. Ms. Mantle appears to rest her proposal upon her claim that these are the only components of transmission that can be "directly tied" to Ameren Missouri's ability to purchase power for its native load or to make off-system sales**.** Mantle Direct, p. 10, l. 19.

Q. Is Ms. Mantle correct that these are the only components that can be "directly tied" to Ameren Missouri's ability to purchase power for its native load or to make off-system sales?

A. No. Ameren Missouri's (and in fact any MISO market participant's) ability to make purchases and/or sales in the MISO market is predicated on the market participant meeting its obligations under the entirety of the applicable MISO tariffs – not just those associated with a specific transmission wire. The participants cannot simply pick and choose which of the mandatory transmission charges they want to pay to buy or sell power in the market. The numerous components of transmission costs that Ms. Mantle seeks to exclude from the FAC are all for transmission services required to engage in those transactions.

Q. How does one know if a transmission charge is "directly tied" to purchases or sales?

A. Directly tying a transmission charge to purchased power or off-system sales is as simple as evaluating the basis for the charge; that is, if the charge is based on the amount of energy acquired or sold (either on a peak demand or total volume basis), then there is a direct link. For example, MISO's Schedule 26A charges for Multi-Value Projects ("MVP") being built in MISO are based upon the MWh of energy bought by the utility (e.g., Ameren Missouri) from MISO's market. I simply don't see how one could validly argue that those charges aren't "directly tied" to that purchase if the cost itself is *based on the amount purchased*.

I would also note that in her surrebuttal testimony filed on behalf of the Staff in File No. ER-2012-0166 (on page 4), when discussing whether Ameren Missouri should be allowed to include charges for MISO's Schedule 26A charges in its FAC, Ms. Mantle acknowledged that Schedule 26A charges *are* directly tied to Ameren Missouri's load when she stated, "just because a cost is incurred to deliver energy to Ameren Missouri customers, does not mean the cost should flow through the FAC."

Q. Given that these transmission charges clearly are directly tied to purchases of energy Ameren Missouri must make to serve its load, what do you make of OPC's attempt to treat such charges as if they are not transmission charges within the meaning of the FAC statute?

A. The OPC's position appears to be an end-run around an argument that it has already lost.

Q. Please explain.

A. In each of Ameren Missouri's last two rate cases (File Nos. ER-2012-0166 and ER-2014-0258), Ms. Mantle argued that Schedule 26A charges arising from MISO MVP projects are not transmission charges, but instead are the "cost of building" transmission lines.[5] The Commission has twice rejected that argument. As it states on page 91 of its Report and Order in File No. ER-2012-0166,

> *However, both Staff's reliance* [via Ms. Mantle's testimony] *on the anti-CWIP statute and its public policy argument rely on a mischaracterization of the nature of the transmission charges that Ameren Missouri seeks to flow through the fuel adjustment clause. MISO may use those charges to allow the transmission owner to recover the cost of constructing the transmission. But from Ameren Missouri's perspective, it*

[5] In File No. ER-2012-0166, Ms. Mantle's argument was that Schedule 26A charges would violate Missouri's "anti-CWIP" statute. In File No. ER-2014-0258, Ms. Mantle didn't mention that statute, but continued her attempt to re-characterize what these charges are.

> *is paying a FERC approved transmission charge, nothing more and nothing less. To Ameren Missouri it makes no difference how the transmission owner uses the revenue it receives through FERC.*

The Commission went on to say:

> *When Ameren Missouri pays the transmission charges it is in the same position as an Ameren Missouri customer who pays their electric bill. The customer pays an established rate for the amount of electricity used. It is meaningless to try to parse out how much of that payment is for the cost of a new transformer in the neighborhood, or how much is paid toward the CEO's salary. The customer is paying a legally established charge that covers all the costs associated with the electricity used and Ameren Missouri is paying a legally established charge that covers all the costs associated with the transmission services it is using.*

Ms. Mantle is making the same argument again, albeit using different language. Basically, having failed at the anti-CWIP/"cost-of-transmission-lines" argument, Ms. Mantle has now come up with a new "directly tied" argument which, like the others, is belied by the facts, including the nature of the charges themselves. That the new argument is, in reality, the old (rejected) argument is obvious when you read Ms. Mantle's discussion of MISO charges arising from the MVPs. Specifically, she states that:

> MISO members are charged as these transmission project costs are incurred. Once the line is built, the users of that line are charged to recover the cost of building the transmission. If Ameren Missouri uses this transmission to purchase power or make off-system sales, MISO will charge Ameren Missouri in order to return investment to the members that paid for the line to be built.

Mantle Direct, p. 10, l. 9-13.

Ms. Mantle also questions the inclusion of costs for MISO's Schedule 42,[6] saying that it is not clear or transparent what this charge is or why it should be considered a transmission charge. It is a transmission charge for the same reason Schedule 26A and

[6] Schedule 42 is titled, "Charge to Recover Accrued and Paid Interest Associated with Prepayments From Entergy Operating Companies' Pricing Zones."

all of the other MISO transmission service schedules are transmission service charges – from Ameren Missouri's perspective, it is simply paying a mandatory, FERC-approved transmission charge based on the volume of purchases the Company makes from the MISO market - nothing more and nothing less - as the Commission clearly understands.

Q. Does that mean that all the dollars of transmission charges OPC seeks to exclude from the FAC would be included in the FAC?

A. Not unless the Commission decides to change its mind regarding its "true purchased power" conclusion first reached in Ameren Missouri's last rate case.[7] Ameren Missouri chose not to re-argue the issue when it filed this rate case. Instead, Ameren Missouri opted to take other steps to address transmission charges, such as reflecting a level of Schedule 26A charges in its revenue requirement that is as current as possible, and asking for a transmission charge and revenue tracker. Consequently, only a small fraction (1.86%) of all transmission charges (including Schedule 26A charges) are proposed to be included in Ameren Missouri's FAC in its current case.[8] Including all of the components of transmission costs in the FAC would not change that percentage. The point of properly defining transmission costs, however, in the context of this case, is that OPC is simply wrong in claiming that MVPs are not transmission charges at all – they clearly are. And putting aside the true purchased power issue, the applicable percentage of *all* the transmission charges should be included in the FAC, as they are now.

Q. When addressing the components of purchased power costs, you made note of several items of evidence demonstrating that purchased power costs

---

[7] Report and Order, File No. ER-2014-0258.

[8] That percentage can vary from case-to-case, depending on the volume of "net" sales and purchases during the historic period used to rebase net energy costs in each rate case. This amount will be updated as part of the true-up process.

consist of many components beyond those recognized by OPC. Does that same evidence demonstrate that transmission costs are also made up of additional components that OPC seeks to exclude from the FAC?

A. Yes, it does. The FERC audit of Ameren Missouri's books found no instance where a transmission charge, including transmission charges that OPC would exclude from the FAC, was not properly recorded as a transmission charge in FERC Account 565. All of Ameren Missouri's FAC tariffs, FAC rate adjustment filings, and prudence reviews have involved FACs that include all these transmission cost components, which have also been detailed in all of Ameren Missouri's monthly FAC reports. Ameren Missouri's FERC Form 1 and Commission Annual Reports have similarly categorized all these components as transmission costs.

Q. Ms. Mantle provides a description of the current methodology used to determine the level of transmission costs (the 1.86% determined for this case noted above) that are included in the FAC on page 9 of her direct testimony. Is this description accurate?

A. No. While Ms. Mantle is correct that the current methodology uses the ratio of what the Commission characterized as "true purchased power" to the Company's total load, her statement that this ratio "is applied to each utility's non-administrative RTO costs" is incorrect.

Q. Please explain.

A. The ratio is only applied to total *transmission* charges recorded in FERC Account 565. It is not applied to any other MISO purchased power cost or off-system sales revenue component recorded in FERC Accounts 555 or 447.

Q. Why is it important to understand to what the percentage is, and is not, applied?

A. Because Ms. Mantle's failure to distinguish between "RTO costs" that reflect RTO transmission charges versus those that reflect RTO charges for the energy and operating reserve or capacity markets could mislead others into believing that Ameren Missouri is not properly administering its FAC tariff.

Q. Couldn't Ms. Mantle simply have been confused by Ameren Missouri's FAC tariff as to what MISO costs the percentage was to be applied?

A. I don't see how. Ameren Missouri's FAC tariff is very specific that this percentage is applied to "the transmission service costs reflected in FERC Account 565." The FAC tariff is also quite specific regarding the MISO purchased power cost components arising from MISO's markets that are included in the purchased power factor (Factor "PP") in the tariff. Nowhere does the tariff state or imply that this percentage is applied to those components.

Q. On page 11 of her testimony, Ms. Mantle is asked "(w)hat is OPC's proposal regarding other MISO costs of which a percentage are currently included in the FAC?" Her response was "(n)o other MISO costs and revenues would be included. While all of these costs and revenues are for necessary services, they are not fuel and purchased power costs or revenues." Do you have any observations regarding Ms. Mantle's response?

A. Yes. First, as I have discussed above, I disagree with Ms. Mantle's proposal to exclude any transmission charges under the guise of claiming that they are not for "transmission." They are indeed for transmission, as explained above and as has been consistently recognized by the Commission.

Second, it is obvious to me that Ms. Mantle's response was intended to be limited to only those MISO transmission charges and revenues, and not all MISO costs and revenues.

Q. Why do you believe that Ms. Mantle's response was intended to be limited to only those MISO transmission charges and revenues, and not all MISO charges and revenues?

A. First, the question refers to "other MISO costs of which a percentage are currently included in the FAC." As just explained, the only MISO charges in Ameren Missouri's FAC that are limited to a specified percentage are MISO transmission charges (there are no revenues of any kind to which the percentage is applied).

Second, the question immediately followed a question and answer regarding which transmission charges Ms. Mantle believes are directly tied to Ameren Missouri's purchased power and off-system sales.

Third, Ms. Mantle's own testimony makes it obvious that she would include other MISO charges and revenues in the FAC. This is obvious since Ms. Mantle specifically identifies capacity and energy purchased through RTO markets to meet native load or to make off-system sales as items OPC recommends including in the FAC. She also recommends the inclusion of off-system sales revenues that are received from the RTO. If Ms. Mantle's response were intended to exclude all MISO costs and revenues other than transmission charges for PTP and NITS, then she would be recommending the exclusion of all the Company's capacity and energy costs and revenues obtained from MISO. She clearly does not intend to do that.

Q. Please summarize your recommendation regarding the inclusion of transmission costs in the FAC.

A. As has always been the case with Ameren Missouri's FAC, all the transmission costs recorded in FERC Account 565 should be included in our FAC, either in an amount that equates to those transmission costs for "true" purchased power (if the Commission does not reconsider its true purchased power decision), or in an amount equaling all its transmission costs if it does. Either way, components of transmission costs should not simply be excluded from the FAC on the mistaken theory that they are not transmission costs at all.

III. OPC'S POSITION IMPROPERLY SEPARATES COST AND REVENUE COMPONENTS THAT ARE INEXTRICABLY LINKED

A. OPC's Position Regarding the Inclusion of OSSR in the FAC

Q. What is OPC's position regarding the inclusion of OSSR in the FAC?

A. OPC's position is arguably unclear. This is because at one place in Ms. Mantle's direct testimony (page 4-5) she seems to suggest that only the margin on off-system sales (a fraction of the total off-system sales revenues) should be included in the FAC, yet elsewhere (page 11) she states that "OPC is recommending the inclusion of off-system sales revenue and the cost to generate or purchase power to make those sales" in the FAC. If all the fuel, purchased power, and transmission costs to make those sales are included in the FAC, but only off-system sales revenue above the costs remains in, that necessarily means that the remaining amount of revenue – equal to the cost of the fuel, purchased power and transmission required to make those sales – would reside outside of the FAC. If this is OPC's recommendation, as with other OPC recommendations, the Commission should reject the separation of costs and revenues from components which offset their value.

Q. Do you believe this is OPC's recommendation?

A. I don't think so for the simple reason that such a recommendation is inconsistent with Ms. Mantle's rationale for why OSSR should remain in the FAC. Specifically, Ms. Mantle states that OSSR should be included in the FAC "because the determination of costs to make off-system sales is an after-the-fact accounting assignment of costs." Mantle Direct, p. 11, l. 12-13. She elaborates on this view by stating "[n]ot including off-system sales revenue in the FAC opens an avenue for errors, resulting in parties having different positions regarding the appropriate fuel cost to allocate to off- system sales, increasing the potential for improper assignment of fuel and purchased power costs." Mantle Direct, p. 11, l. 15 to p. 12, l. 2. In her direct testimony in Kansas City Power & Light Company's current general rate proceeding, File No. ER-2016-0285, she was even more pointed in her response, stating that "(n)ot including off-system sales revenue in the FAC opens an avenue for errors, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales, and would increase the potential for imprudence."

Q. Assume that OPC's recommendation is in fact to include all of the OSSR and all the fuel, purchased power and transportation costs (as Ms. Mantle would define those terms) to make those sales in the FAC. What concerns would you have with that recommendation?

A. That recommendation would fail to recognize a wide variety of incremental costs of off-system sales that are required to make those sales – the same cost components which OPC is seeking to have excluded from the FAC. Ms. Mantle would seemingly have the Commission believe that the only incremental costs of off-system sales are fuel, purchased power and transportation ***as she defines those terms***. That is incorrect.

Q. Why would it be problematic to exclude certain incremental costs of making off-system sales if those costs are found not to be fuel, purchased power or transportation?

A. It is problematic as it disconnects changes in those incremental costs from the changes in the benefit provided by the OSSR. The OSSR only exist if the costs are incurred. If these costs incurred to make the sales are excluded, we are now faced with a situation that whenever off-system sales volumes increase, Ameren Missouri must now bear the entire burden of the increase in these costs, while customers enjoy 95% of increased OSSR that would not have existed if that cost had not been incurred. Conversely, whenever off-system sales volumes decrease, Ameren Missouri would retain all the reduction in those costs while customers would bear 95% of the burden of the reduction in OSSR. Either way, such a result is illogical and unfair.

Q. Do you agree with Ms. Mantle's recommendation on page 11 to include all OSSR in the FAC?

A. Yes. I agree that OSSR should be included in the FAC. Including OSSR in the FAC maintains the tie between revenues and the cost components which they offset and the benefits that are provided. I also agree with Ms. Mantle that one cannot objectively determine the split between fuel, purchased power [and transmission] costs (as either of us would define those terms) for load and for off-system sales. Such a determination necessarily varies due to subjective judgments utilities must make to develop estimates of those splits. Where I differ with Ms. Mantle is that she would exclude a wide variety of incremental costs of off-system sales that are required to make those sales. As just explained, all the incremental costs of making those sales should be included in the FAC.

Q. How does Ms. Mantle's recognition of the difficulty of determining the appropriate split between load and off-system sales relate to OPC's recommendation to exclude many components of purchased power, as discussed above?

A. The very same difficulty about which Ms. Mantle rightly expresses concern regarding OSSR would also exist if components of purchased power costs that are offset by certain components of OSSR are excluded from the FAC, or if certain components of purchased power costs that offset other components of purchased power costs are excluded. Yet Ms. Mantle recommends that these mismatches should occur.

B. <u>General Concerns Regarding the Separation of Cost and Revenue Components</u>

Q. Please elaborate on why it is improper to separate cost and revenue components of purchased power, transmission and off-system sales from other components of purchased power, transmission and off-system sales.

A. As already discussed, purchased power, transmission, and OSSR consist of their various components. Certain of these components are inextricably tied together, either due to one component serving to partially mitigate against the risk of adverse price movements in the other components (providing a hedge for customers' benefit) or because the component itself is a result of the cost of the other component not by itself being reflective of the total cost of the purchased power or transmission.

Q. What are some examples of these components?

A. Forward energy and capacity transactions at fixed prices, whether physical or financial in nature, are used to mitigate (hedge) the risk of adverse price movements for the energy component of purchased power costs and revenues from off-system sales of energy which otherwise would be priced only in the day-ahead or real-time spot markets. Similarly, components of purchased power recorded in Account 555, such as ARRs and FTR offset other components of purchased power recorded in Account 555, that is, the cost of congestion which is embedded in the locational marginal price[9] of the day-ahead energy acquired to serve the utility's load. Another example is ancillary services revenue recorded in FERC Account 447, which offset the cost of acquiring the ancillary services component of purchased power recorded in Account 555. There are other examples, including MISO make-whole payments recorded in Account 447 that are funded by the revenue sufficiency guarantee and revenue neutrality uplift components of purchased power recorded in Account 555. All of these components are inextricably connected to each other and should not be separated.

C. Forward Energy and Capacity Transactions in Account 555

Q. Has Ms. Mantle recommended the exclusion of forward energy transactions from the FAC?

[9] The locational marginal price ("LMP") that is paid for a MWh of energy bought or sold in MISO's market itself consists of three components: energy, congestion and losses. MISO does not break out those components in their billings, but Ameren Missouri (and probably other utilities) attempt to isolate each component of the LMP for managerial accounting purposes.

A. Not by name. However, by recommending that the only purchased power costs included in Ameren Missouri's FAC are the costs of energy from long-term bilateral contracts or spot energy from MISO's market, she has effectively recommended that energy charges from bilateral contracts of less than one year and all financial swaps should be excluded. This means again that she has excluded many components of purchased power, including all financial swaps and short-term bilateral energy contracts, which mitigate the risk of adverse price movement for the energy component of purchased power, just as the long-term bilateral contracts she has decided can be included in the FAC would. This makes no sense.

Q. Can you discuss this concern further?

A. Yes. Ms. Mantle's proposal does not provide for the inclusion of financial swaps of *any* term or the cost of short-term bilateral contracts for energy. Excluding these items from the FAC is illogical given that she has specifically recommended the inclusion of the cost of energy from long-term bilateral contracts.

Q. Why is it illogical to exclude the cost components of purchased power related to financial swaps and short-term bilateral contracts for energy?

A. First, it is illogical because Ms. Mantle seems to be differentiating between a financial swap and a fixed price bilateral contract even though both transactions accomplish *exactly the same thing*: fixing the price of power for a future period.

Second, it simply does not make any sense that Ms. Mantle would only support allowing Ameren Missouri to enter into transactions to mitigate its price risk if that transaction is at least one year in length, whether it was a swap or a bilateral transaction.

It becomes even more nonsensical if one were to believe that long-term is somewhere between three and five years,[10] as Ms. Mantle has opined in the past. (The generally accepted market definition of long-term is at least one year). Under Ms. Mantle's position, the utility's customers would illogically bear the full risk of adverse price movement for periods of less than at least one year.

Q. Please explain how a physical bilateral contract and a financial swap serve the same purpose of fixing the price for a forward period.

A. They fix the price of a transaction that would otherwise settle at a spot market price in the future. In the case of a physical bilateral contract, the utility will make a purchase at a fixed price and take delivery of energy from the counterparty at a specified point. The utility will still purchase energy from MISO to serve its load, but the energy acquired through the bilateral contract will also be settled (sold) into the MISO market. This means that the utility pays the bilateral contract counterparty a fixed price for the energy and sells it into the MISO market and receives a variable spot market price. The utility then purchases energy from the MISO market to meet its load obligation at that same variable spot price. Since it both received and paid a variable spot price, the utility is left having paid a fixed price for the energy. In the same manner, financial swaps include a fixed price which settles against the variable spot price.

In the case of a financial swap, the utility enters into a financial arrangement with a third party which "swaps" the utility's spot price exposure for a fixed price, with the agreement specifying what price point in the market will be used to calculate the settlement value. When the transaction comes to delivery, the utility purchases the

[10] Mantle Deposition, File No. EO-2010-0255, p. 30, l. 23 to p. 31, l. 7 (Indicating that "long-term" was between three and five years).

energy from the MISO market to meet its load obligation at the variable spot price. Unlike the physical bilateral contract, the utility does not buy energy at a fixed price which is then sold into the market at the variable spot price, but simply makes a financial settlement with the counterparty for the difference between the fixed price and the variable price. Since the variable spot price is netted out, this leaves the utility paying an amount equal to the fixed price – just as it would with the physical bilateral contract. One advantage of the financial transaction over the physical bilateral transaction is that it avoids certain market settlement charges which are based on transaction volumes, and thus may be a lower cost option, which benefits customers.

Q. If the financial swap provides an identical benefit as a physical bilateral contract and is potentially a lower cost option to mitigate the risk of adverse price movements for purchased power, what would the effect of OPC's proposal to allow the cost component for long-term bilateral contracts to remain in the FAC but exclude the cost component for financial swaps be?

A. This is in some ways the same scenario that Ms. Mantle describes in her testimony regarding Ameren Missouri making the choice between treating coal with activated carbon versus trona. Mantle Direct, pp. 16-17. Setting aside any question of the accuracy of Ms. Mantle's characterization of what functions activated carbon or trona perform, her example is meant to discuss two alternatives to address the same issue. In her example, and with bilateral contracts and financial swaps, there are two tools available to accomplish a purpose (fix the price of energy, treat fuel before it is burned), but if OPC had its way only one is included in the FAC. Ms. Mantle believes that having one tool in an FAC and another tool outside it creates disincentive for the utility to use the tool outside the FAC. If that were true, though, it would necessarily follow that excluding financial swaps or short-term bilateral contracts while including long-term bilateral contracts in the FAC would create a similar disincentive to use financial swaps or short-term bilateral contracts which would be outside the FAC, even if the circumstances warrant their use.

Simply put, these two examples – trona versus carbon and bilateral contracts versus financial swaps – are neither identical in nature nor truly analogous. In Ms. Mantle's activated carbon versus trona example, the utility *must* use one of those two tools to treat the coal. In the case of short-term bilateral contracts and swaps, the utility is *not* required to hedge the underlying price risk at all; it does so to mitigate price risk *on behalf of its customers*. The cost of providing that mitigation should not be divorced from the mitigation itself.

As Ameren Missouri witness Jaime Haro testified in File No. ER-2014-0258 (surrebuttal testimony, p. 20, l. 5-9), "(a)s soon as the tie between the underlying risk (price volatility for excess generation) and the hedging transaction is broken, the financial swap is no longer a hedging instrument, it is a speculative instrument. Ameren Missouri is not a merchant generator and we do not speculate on energy transactions. As a consequence, we would cease entering into such transactions." While Mr. Haro was speaking to Ms. Mantle's recommendation in that case that the costs and revenues associated with financial swaps entered into for off-system sales be excluded from the FAC, this principle applies equally to hedges entered into for purchased power. If the financial swap component of purchased power were removed from the FAC, those transactions would no longer serve as hedges, leaving only the long-term bilateral contract as an available tool – one which may have a higher cost for customers.

Q. Why does it not make sense to only allow Ameren Missouri (or presumably any Missouri utility) to only enter into long term transactions to mitigate price risk on behalf of customers?

A. It is unreasonable to believe that Ameren Missouri or any utility only has long-term price exposure. MISO operates an energy and ancillary services market. That market is co-optimized – i.e., by their very nature, energy and ancillary services markets work together. The energy market, however, is not forward in nature; the longest period ahead of delivery for which it transacts is the next day – and then only for the day-ahead market. As such, when a utility has an open position in the market – either long (projected to have more resources than load obligation) or short (projected to have more load obligation than resources) – it is at risk of adverse price movements in the MISO spot market. The utility does not know what the price will be when its generation and/or load ends up clearing in the marketplace. When a utility has a long position, it is generally concerned with the risk that the market prices will decrease from current expectations and may seek to lock in a price with a forward contract – either physical or financial in nature. Similarly, when a utility has a short position, it is generally concerned with the risk that the market prices will rise from current expectations and will seek to mitigate that risk by locking in a price for the energy component of purchased power now.

Certain utilities are always short – they have a load obligation and own no resources. Others are always long – they have resources and no load obligation. Many more, however, have both resources and loads. While these utilities may tend to be generally long or generally short, there is no way to know that this will always be the case. This is especially true when one recognizes that the determination of a short or long position is made by calculating the amount of resources that are not only available, but are also *economically* available to offset the cost of serving the load with energy purchased from the market. It is sound (and long-standing) practice for utilities to rely on the marketplace when the cost of doing so is lower than the cost of generating energy from their own resources.

OPC's recommendation would create a situation in which a utility could not project itself in a short position and still be able to hedge that exposure unless the contract used to hedge the exposure was at least one year in length. Indeed, it would be illogical – and potentially imprudent – to make a bilateral purchase for a full year if the short condition did not exist for at least that long. The only option available to the utility would be simply waiting and purchasing the energy in the spot market at the going price.

Q. Isn't your concern simply hypothetical, given that Ameren Missouri is generally long on generation?

A. No. Far from being hypothetical, the concern is quite real. For example, Ameren Missouri's Callaway Nuclear Plant is its single largest generating unit. Callaway must be taken out of service every 18 months for refueling. In accordance with long-standing, prudent practice, these outages are timed to coincide with time periods that historically have low market prices for power. Ameren Missouri projects its forward energy position using forward market prices. If these market prices fall below Ameren Missouri's projected cost of generation, its projected "in the money" generation will decrease. If a sufficient amount of generation is projected to be "out of the money," it will project a short condition. This does not mean that the Company does not own sufficient generation resources to meet its load obligation; it simply means that these units are projected to operate at lower levels due to economic dispatch considerations, resulting in an increase in net purchased power on its books. Ameren Missouri obviously does not know what the actual market prices will be during the scheduled outages, but the opportunity exists for the Company to lock in a price for purchased power now that is lower than its cost of generation to hedge that cost exposure. Under OPC's proposal however, Ameren Missouri would not have any reason to enter into such a hedge – whether it be with a swap or a bilateral contract – as the exposure only exists for a short period of time. Customers then would be left bearing the spot market costs, whatever they may be, when the outage comes about.

Other examples exist for time periods as short as a few hours, for example when a utility finds itself short inside the market day for a few hours across the peak due to an unplanned unit outage. OPC's proposal would exclude recovery of any cost related to fixing the price for the balance of the day and leave the customer exposed to real time prices later in the day. There are far more potential scenarios involving a utility being short for periods of less than one year than there are of a utility being short for periods of one year or more.

Q. Would a utility that is normally a net purchaser be harmed by OPC's proposal?

A. Yes. Such a utility, and more importantly its customers, would be harmed by OPC's proposal because the amount by which the utility is short would not be the same in every month, let alone every week or every hour. When the only tool available to mitigate a utility's spot market price exposure is long-term bilateral contracts, that utility is left with two options: 1) continuing to carry a considerable amount of spot market exposure, whether it purchases the absolute minimum load for every hour of a year and buys the rest, or it buys something greater than the minimum and sells its excess or buys its deficiency in the spot market; or 2) enter into a full requirements, load-following purchased power agreement with a third party.

The first option carries all the downsides related to prohibiting short-term price mitigation discussed above. The second option carries a cost premium to compensate the seller for bearing all the utility's load variability risk; a premium that may well be greater than the cost of the utility managing its own risk.

D. Auction Revenue Rights and Financial Transmission Rights in Account 555

Q. Why would it be improper to exclude ARRs and FTRs from the FAC?

A. As noted earlier, ARRs and FTRs are components of purchased power (actually, they are revenue streams recorded in Account 555, which some view as a "negative cost") that serve to offset the cost of congestion embedded in the LMP for energy purchased to serve load. Again, the Commission should reject the separation of costs and revenue components from other related components that offset their value.

Q. What does it mean that ARRs/FTRs offset the cost of congestion?

A. To understand how ARRs/FTRs offset the cost of congestion, I will provide a bit of history on the development of the LMP that Ameren Missouri pays to purchase energy from the MISO market and that it receives for the energy that it sells into that same market.

LMP is made up of three components: a marginal energy component ("MEC"), a marginal losses component ("MLC"), and a marginal congestion component ("MCC"). For a given hour, in the day-ahead or the real-time market, the MEC is the same for every commercial pricing node ("CpNode") in the MISO market.[11] The other two components are unique to each CpNode and are based on the current conditions of the transmission system. When the LMPs for two points are compared, the difference is attributable to losses (the difference in the MLC component) and congestion (the difference in the MCC component).

Prior to the use of LMP in centrally administered RTO markets, transmission congestion on the system was addressed by instructing market participants to terminate energy schedules between transmission control areas. While non-firm transmission schedules were the first to be "cut," firm schedules could also be cut if non-firm cuts didn't resolve the situation. Since these corrective actions were not directed at specific generators or loads that would be best able to resolve the situation, it was frequently necessary to cut a very large amount of transmission schedules to obtain the desired congestion relief. These orders to cut schedules were called "TLRs," which stood for "transmission loading relief."

While transmission schedules between control areas were being cut, inside a utility's own control area, the energy just flowed between the generators and the load – what MIEC witness Dauphinais termed as self-supplied power in File No. ER-2014-0258 – unless there was an emergency which required the curtailment of load. The frequency

[11] A CpNode is a location in the market.

and magnitude of these TLRs was quite disruptive, and the process overall was an inefficient means of solving congestion problems.

The inherent market inefficiency and disruptiveness of a system that relied on TLRs led to the establishment of the LMP-based markets we have today, both in MISO and the Southwest Power Pool ("SPP") (and elsewhere). In an LMP-based market, it is no longer necessary for the system operators to order TLRs between areas, as the necessary response from both load and generation is achieved through price signals. This means that the scope of curtailments is greatly reduced, resulting in fewer system disruptions and much greater efficiency.

Q. How does LMP address congestion, reducing the disruption and increasing the efficiency of the market?

A. When congestion on the system occurs (in real-time) or is modeled to occur (in day-ahead), the LMP received by generators or paid by load on the low (less congested) side of the congestion is depressed because the MCC of the LMP at that CpNode is lower. This provides an incentive for price sensitive loads to increase their demand and for generators to reduce their output. In certain cases, the LMP may actually go negative if necessary – requiring the generator to pay the RTO if it continues to generate or allowing the load to be paid to take energy. On the other, high (more congested) side of the congestion, the price paid by the load or received by generators is increased. This provides an incentive for generation on that side to increase its output (or if the unit is off-line, to be brought on-line) and for loads to reduce their demand. It is generally true that congestion exists between the load and generation. The further apart load is from generation, the more likely that there will be congestion and the higher the differential in the MCC will be.

Unlike TLRs, the use of LMP targets exactly those resources and loads that are best able to resolve the issue on the system. LMP also allows market participants to determine what is in their best financial interests rather than simply being on the receiving end of a TLR. Under LMP, if a market participant has a transaction from point A to point B, as long as it is willing to pay the net LMP (LMP paid at the load point minus the LMP paid at the resource point), it can continue to use its own resource to offset the cost of servicing its load through self-scheduling. However, market participants generally find it in their financial best interest to back down their generation in response to a price signal, which helps relieve the congestion and lower the LMP at the point they the energy is acquired to serve their load. As a result, their overall cost of purchasing power for their load is lowered.

Q. How does this LMP-based system relate to ARRs and FTRs?

A. Load serving entities ("LSE"), including vertically integrated utilities (those who both own generation resources and those with a load obligation) like Ameren Missouri, were rightfully concerned that the advent of LMP-based markets might increase their own costs to serve their load obligations, since the price received from selling all their resources into the market was expected to be less than the price paid to the market for purchasing their load requirements, due to greater market efficiencies made possible by the LMP-based market. While part of this difference represents transmission losses, which also existed prior to the advent of LMP, the rest of the difference represents the cost of congestion within the purchase price.

To address the LSE's concerns (and undoubtedly the concerns of their regulators), and to maintain the historical relationship to the use of the system for their resources and their loads, FTRs were created. FTRs compensated LSEs for the difference in the congestion components in the day-ahead LMP that existed between the resources they had historically utilized to meet their load obligations, and the loads themselves. In doing so, these entities were placed back into the same relative financial position (for the portion of their generation that hedged the cost of their load obligations) that they would have been in without the LMP-based market and using the firm transmission service (either through firm point-to-point or firm designated network service) that was traditionally used to serve their load.

Later, the RTOs replaced the allocation of FTRs with lump-sum ARRs, which are cash payments. Owners of ARRs have the option to either take the lump sum payment or convert the ARRs to FTRs. The payments received from the RTO for an FTR are based on the actual hourly congestion amounts. As such, FTRs track changes in congestion throughout their effective period, and arguably provide a more complete hedge against the cost of congestion embedded in the purchase price than simply taking the lump-sum ARR payments. As with other hedges, this value will fluctuate as the underlying cost fluctuates. Consequently, FTR revenues will increase when the cost of the congestion component of purchased power increases, and will decrease when the cost of congestion component of purchased power decreases.

Q. You have explained how ARRs/FTRs provide a hedge against the cost of congestion embedded in the purchase price, but can you explain why it is appropriate to include those items in purchased power?

A. Yes. The level of ARR/FTR revenues is inextricably tied to the cost of the day-ahead energy purchased from the RTO to serve the utility's load obligation. In the absence of ARRs and FTRs, the utility's total purchased power expense – a cost ultimately borne by its customers – would be higher. It is the *combination* of these offsetting cost and revenue components that establishes the cost of purchased power.

Q. Are the dollars associated with congestion and ARR/FTR revenues significant?

A. Yes. Ameren Missouri's actual totals for these amounts in recent years are shown in the table below (negative numbers reflect revenues).

	Congestion	*ARR/FTR*	*Net*
2010	$16,455,474	($16,936,072)	($480,598)
2011	$12,912,706	($20,750,528)	($7,837,822)
2012	$14,771,232	($26,858,744)	($12,087,512)
2013	$26,576,317	($43,106,464)	($16,530,147)
2014	$14,764,545	($17,212,626)	($2,448,081)
2015	$19,914,424	($26,523,789)	($6,609,365)
YTD2016	$9,647,081	($13,729,981)	($4,082,900)
TOTAL	**$115,041,779**	**($165,118,204)**	**($50,076,425)**

Q. What would the consequences be if OPC's proposal was adopted, excluding ARRs and FTRs from the FAC?

A. The first and most obvious consequence of implementing OPC's proposal is that, should history repeat itself, an average of more than $23 million in FTR revenues would be excluded from the determination of total purchased power costs in the FAC *each year* (approximately $165 million/6 years and 11 months).

This would be yet another break between underlying congestion risk and the very tools included in the market's operation to manage that risk. By breaking that link (once again taking Ms. Mantle's activated carbon versus trona disincentive argument at face value) means the utility would no longer have an incentive to actively manage the congestion exposure.

The utility would also find itself in another untenable situation. Any time the cost of congestion increased relative to what was included in the determination of net base energy costs that set the base in the FAC, customers would be required to absorb the higher congestion costs. At the same time the utility would not be able to offset the increased cost of congestion with the related increase in the value of the ARRs and FTRs (as congestion increases, so does the value of the ARRs and FTRs) because the ARR and FTR components would not be in the FAC. Conversely, any time the cost of congestion fell, the utility would be required to not only absorb the drop in the value of the ARRs and FTRs because again, they would not be in the FAC. At the same time, the utility would be required to pass through to its customers the value of the reduction in congestion that led to the loss in ARR/FTR value in the first place since the congestion *is* reflected in the FAC.

The intertwined relationship between ARR/FTR and energy costs is obvious; because ARRs and FTRs are inextricably tied to the underlying cost of congestion (which is itself embedded in the LMP), those ARRs and FTRs should not, as a matter of logic, fairness and operation of the markets, be excluded from the FAC.

Q. Couldn't this problem be solved by excluding the congestion cost component of the LMP from the FAC as well?

A. For the same reasons given by Ms. Mantle for including OSSR in the FAC, the answer is "no." There is also no need to do so – ARRs and FTRS are a component of purchased power costs inextricably linked to the energy component of those costs.

Q. Why is the answer "no?"

A. First, as noted previously, to determine the cost of congestion, one must compare the marginal congestion component in the LMP paid for energy purchased to serve load to the marginal congestion component in the LMP received by the generators whose output has been designated as offsetting the cost of energy to serve the load. This is similar to being able to determine the split between the cost of fuel or energy purchased to make sales versus to serve load.

To calculate the cost of congestion attributable to load entails exactly the same process that Ms. Mantle states would require an "after-the-fact accounting assignment of costs" and that would open "an avenue for errors, resulting in parties having different positions regarding the appropriate fuel cost to allocate to off-system sales, increasing the potential for improper assignment of fuel and purchased power costs." Being able to identify what generation resources are allocated to load or allocated to sales is exactly the same process – the only difference being if you are looking at the top or the bottom of the generation stack (i.e., the dispatch order of each generating unit). In either case, the determination is made through an internal calculation at the utility, based on subjective decisions made by the utility, just as is the case when attempting to separate fuel and power purchases for load versus for sales. This is not a simple or standardized process, as Ms. Mantle recognizes.

Secondly, there are no FTRs to offset congestion in the real-time market. As such, if we keep ARRs/FTRs together with the congestion cost component of purchased power that they offset (as we must). Assume that FTRs/ARRs and the congestion they offset were removed from the FAC: we would have a situation where the energy cost component of purchased power in the day-ahead market would be defined differently than the energy cost component of purchased power in the real-time market. This result makes no sense. Such a scenario would unnecessarily complicate the administration of the FAC tariff and, in Ms. Mantle's own words, open "an avenue for errors, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales, and would increase the potential for imprudence."

E. Ancillary Services Costs in Account 555

Q. Why would it be improper to exclude the ancillary services component of purchased power from the FAC?

A. Ancillary services are a component of purchased power. Their cost is offset by the revenues received for the sale of ancillary services, which are reflected as OSSR in Account 447. The Commission should reject the separation of costs and revenue components from other components which offset their value.

Q. Why do you say the cost of this component of purchased power is offset by the revenues received for the sale of ancillary services that are a component of off-system sales?

A. As with energy, utilities in RTOs with an ancillary services market (such as MISO) purchase their entire ancillary service requirements for load from the RTO market and sell all the ancillary services provided by their generators into that same market. Unlike the energy market, however, there is no FERC-mandated netting requirement for accounting purposes.

In the energy market, in an hour in which the utility has more MWhs of generation sold to the market than MWhs of energy purchased to serve load, the utility will record a net sale for the difference in both MWhs and dollars. A net purchase is recorded if it purchases more than it sells.

In the ancillary services market, however, the utility records all the costs of ancillary services purchases in Account 555 and all revenues from ancillary services sales in Account 447.

Q. Why is this lack of netting for accounting purposes important in this discussion?

A. It is important because OPC is recommending the exclusion of all ancillary services cost components from the FAC without a commensurate recommendation that any of the revenue components of ancillary services should be excluded from the FAC. As such, OPC would have significant revenues remain in the FAC that only exist because we now record significant costs to purchase ancillary services from the market rather than self-supply them (as was done before the RTOs created the ancillary services markets).

Q. Can you explain what you mean by this?

A. Yes. At the time the FAC statute was drafted, vertically integrated utilities such as Ameren Missouri provided their own ancillary services, allocating the required level of ancillary services across their generating units. To be able to provide spinning reserve and regulating reserve, generating units that might otherwise have been dispatched at higher generation levels to provide energy were held back enough to allow the unit to respond. The decision regarding which units should be backed down was restricted to the number of units under the utility's control. There was not, however, an explicit purchase of ancillary services to meet the requirements of the utility's load as there is now. Sales of ancillary services were generally limited to those taking transmission services within the utility's control area.

With the advent of ancillary services markets within the RTOs, utilities no longer self-provide their ancillary service requirements; it is more efficient to utilize the ancillary services market which, in fact, works in tandem with the energy market (i.e., they are co-optimized markets). Today, we purchase all of our ancillary services requirements from the market and sell all of the ancillary services provided by our generators into the market – just as we do for energy.

Q. Why is it more efficient for Ameren Missouri to buy all its ancillary service requirements from the market and then sell all ancillary services to the market?

A. Because the co-optimized ancillary services and energy markets lower overall costs. This is because less generation must be held back to provide ancillary services and more generation (when economic in a given hour) can be used to provide energy. As noted, prior to the advent of ancillary services markets, utilities self-provided their ancillary service requirement, so they had limited choices of where to hold those reserves. In an RTO-administered ancillary service market, there is a much greater pool of resources available to provide those services. By administering both the energy and the ancillary services market simultaneously, the RTO can co-optimize those two markets. Additionally, when the ancillary service requirements of all the loads were combined, the aggregate amount of ancillary services required of the pool was less than the total of all the individual requirements under the prior system.

The resources that are most cost efficient *to* provide energy *will* provide energy. Those most cost efficient *to* provide ancillary services *will* provide ancillary services. With very limited exceptions, if a generator is clearing for ancillary services, it is because it is more profitable for it to do so than to clear for energy.

Generation resources are no longer limited in the amount of ancillary services utilities can sell by their own control area requirements and, as such, have new sources of revenue available to them.

Through this co-optimization, the utilities' purchased power costs net of off-system sales revenue is lower than it would be if it self-supplied all its own ancillary services. Schedule AM-R1 to my testimony provides an example of how co-optimization works.

Q. Your example has illustrated why co-optimization is better than self-supply, but how does this support your argument that the ancillary services cost component of purchased power should not be excluded from the FAC?

A. This example further demonstrates that one cannot separate cost and revenue components that offset each other without completely ignoring the fact that the energy and ancillary services markets are co-optimized. Moreover, it makes no sense to do so; that co-optimization, by design, lowers costs through more efficient market operations and those reductions are reflected in the FAC.

Q. How do you recommend that the Commission treat ancillary service costs in the FAC?

The Commission should reject the separation of costs and revenue components from other components that offset their value. All the ancillary service revenue components of off-system sales and all the ancillary service cost components of purchased power should remain in the FAC.

Q. Couldn't that be accomplished by excluding the offsetting ancillary service revenues from the FAC?

A. Excluding both the offsetting ancillary service revenue components of off-system sales *and* the ancillary service cost components of purchased power would seemingly avoid the problems associated with separating these components. However, this would be at a significant cost, adding extreme levels of complexity to the administration of the FAC tariff. It also does not help to exclude all ancillary service revenues from the FAC (and not just those which offset ancillary service costs) because customers would lose the benefit of increases in those revenues between rate cases.

Q. How would removing the offsetting ancillary service revenues from the FAC complicate the administration of the FAC?

A. The amount of any given ancillary service that a utility purchases in an hour is not equal to the amount of that service it sells in that hour. In some hours, it purchases more of a given service than it sells, and in other hours, it sells more than it purchases. This is the same situation as exists with the purchase and sale of energy – but here it exists for *three different ancillary services*.

Excluding the offsetting ancillary service revenues from the FAC along with the ancillary services cost components of purchased power requires basically the same process (except in triplicate) that Ms. Mantle states would require "an after-the-fact accounting assignment of costs" and that would open "an avenue for errors, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales, and would increase the potential for imprudence." The utility would have to be able to identify which ancillary service sale by a given generation resource for a given type of ancillary service would be allocated to offset the cost of what was purchased by load. That determination is made through an internal calculation at the utility, based on subjective decisions made by the utility.

F. RSG and RNU Charges

Q. Why would it be improper to exclude these components of purchased power from the FAC?

A. MISO make-whole payments to generators (recorded as revenues in Account 447) are inextricably tied to the cost of energy. RTOs, including MISO, are revenue neutral by nature. The amount that they pay out to generators must be collected from those purchasing energy from the MISO market. In a perfect world, the revenue paid to generators via the LMP would exactly equal the energy costs paid by the loads via LMP. However, we don't live in a perfect world; these revenues do not perfectly match. When they result in more revenues paid to the generators than amounts collected from the loads for purchased power, the shortfall is collected from the loads through the RSG and RNU component of purchased power. Had the price charged for the energy adequately compensated the generator, then the LSEs would not need to pay more to cover the true cost of the power. However, when the price does not provide adequate compensation, the charges are necessary. Clearly, then, the RSG and RNU are components of the total cost of purchased power. Notably, OPC has not recommended the exclusion of any revenue component for make-whole payments, even though it wants to exclude the charges that create the pool of dollars needed to make those payments.

Q. What leads to make-whole payments for generators, and thus the RSG and RNU components of purchased power needed to fund them?

A. The various causes of make-whole payments are relatively complex, but at their core is a common cause: these are revenues from MISO to the generator caused by MISO's dispatch of the utility's generation when the variable market price is lower than the offered cost of the generation. These make-whole payments restore the generator to a position no worse than it would have been in had it not allowed MISO to dispatch its units in this manner.

Q. How do loads benefit from generators allowing MISO to dispatch them in this manner?

A. The cost of purchasing power from the MISO market is lower, and the overall reliability of the MISO dispatch is retained. Generators are required to follow MISO's instructions to dispatch them in this manner. Without these market features, MISO would be required to either commit more expensive resources, carry greater levels of spinning reserve, or in extreme cases, potentially curtail loads.

Q. Are there other costs that are collected through RSG or RNU?

A. Yes. In particular, real-time imbalances in congestion are settled through RNU on a load ratio share. MISO calculates the total amount of congestion costs for entities acquiring energy in real-time and compares that to the total amount of congestion revenues received by selling energy into the market. Any difference – positive or negative – is allocated on a load ratio share through RNU. If LMPs were perfectly calculated every five seconds, this would be unnecessary. These differences collected through RNU, therefore, simply represent an under- or over-payment for purchased power.

Q. How do you recommend the Commission treat the MISO make-whole payment cost components of purchased power in the FAC?

A. The Commission should reject the separation of costs and revenue components from other components that offset their value. All the MISO make-whole payment components of purchased power should remain in the FAC.

IV. <u>INCENTIVES</u>

Q. In her discussion of why OPC is recommending a change to Ameren Missouri's FAC incentive mechanism (moving from 95%/5% to 90%/10%), Ms. Mantle claims that Ameren Missouri decided that it changed how it managed its capacity within the MISO market as a result of the "shutdown of the Noranda aluminum facility." Is she correct?

A. No. Ameren Missouri could not have changed how it managed its capacity within MISO because the smelter shut down, because we changed how we managed our capacity within MISO *nearly a year before* the smelter shut down.

Q. Does OPC know this?

A. It should. I explained this in detail in my direct testimony filed in this case more than six months ago.

Q. Despite Ms. Mantle's mistake regarding why Ameren Missouri changed its strategy for managing its capacity, is a discussion of that decision relevant to any of Ms. Mantle's recommendations in this case?

A. Yes it is.

Q. Why?

A. Because what we did directly rebuts Ms. Mantle's claim that there ought to be greater sharing in the FAC. We made a change in our approach for participating in MISO's capacity market that saved our customer $27 million in one year, and did so with a sharing percentage of 95%/5%. Obviously, we don't need a "greater incentive" to take steps to minimize our net energy costs for the benefit of customers.

V. <u>NEW CHARGE TYPES FROM THE RTO</u>

Q. Ms. Mantle claims that "(w)ith the MISO costs limited as proposed by OPC, there would no longer be a need for a process to include new MISO charges and revenues that are 'like' MISO costs and revenues already included in the FAC." (pg. 19 l. 13-16). What is her point?

A. I believe Ms. Mantle is suggesting that if the Commission opted to adopt OPC's recommendation,[12] then the need for a provision that has (with some modifications) been in the Company's FAC tariff since 2013 would be eliminated. This provision allows for the inclusion of costs and revenues that did not fall within an existing RTO charge type when the FAC tariff was approved, so long as the new RTO charge type reflecting the costs or revenues possess the characteristics of, and are of the nature of, existing costs and revenues in the FAC. Ameren Missouri witness Lynn M. Barnes also addresses why this provision should remain in the FAC tariff in her rebuttal testimony filed in this case.

[12] Specifically, the OPC's recommendation to only allow in Ameren Missouri's FAC those MISO charges that are "capacity and energy purchased through RTO markets to meet native load or to make off-system sales" and charges for Point-to-point ("PTP") and network integration transmission service ("NITS").

Q. Do you agree with Ms. Mantle's claim that the need for this provision would be eliminated if OPC's recommendations for the FAC were adopted?

A. No. The need for this provision will exist so long as the cost and revenue components of purchased power, off-system sales, and transmission included in the FAC tariff are prescriptively tied to charge types and identified MISO schedules that happened to exist when the FAC became effective after each rate case.

Q. Are you sure Ms. Mantle isn't addressing the general "energy" and "capacity" provisions in the FAC tariff?

A. I see nothing to indicate that her recommendations are limited in that fashion. There is nothing in her testimony (in this case or any past case) indicating to me that she is now willing to abandon her long-held position that the FAC tariff must include a prescriptive listing of every charge type and schedule.

Not only would this be contrary to her past positions, but the fact that she still believes such a prescriptive list must be in the FAC tariff is reinforced by her quite recent testimony in KCP&L's pending rate case (File No. ER-2014-0285), where she recommended limiting SPP integrated market costs and revenues in purchased power to four very specific SPP charge types.

Q. If Ms. Mantle were to state which MISO charge types should be included in the FAC, and if she were to claim that there could never be any others until another rate case occurs, would you agree?

A. No, I would not agree. Ms. Mantle's testimony suggests that the Commission simply assume that when MISO implements or even modifies a new charge type that the related cost or revenues are new (i.e., they would not be for purchased power, off-system sales or transmission). In many, if not most cases, that simply is not true – MISO is simply rearranging how existing costs and revenues arising from its market are accounted for and settled. If indeed a charge type was implemented that did not possess the characteristics of, and were not of the nature of, existing costs and revenues in the FAC, Ameren Missouri's tariff already would not permit those costs and revenues to be included in the FAC.

Ms. Mantle's testimony also suggests that the Commission assume the implementation of a new charge type that reflects changes in where and when a cost or revenue occurs, or that divides it into smaller portions, somehow makes it into something other than fuel, purchased power or transportation. It does not.

Q. Please explain this last statement.

A. The statute refers to fuel, purchased power and transportation. It doesn't say "purchased power, but only if the contract for that purchased power is more than a year." And it doesn't say that if the purchased power is from an RTO, it is only really "purchased power" if the RTO labels it a certain way and had done so when a particular FAC tariff took effect.

Q. Given Ms. Mantle's historical insistence on a prescriptive FAC tariff and the existence for the past several years of a provision that allowed charge type changes to be recognized, are there examples of situations where the absence of such a provision would have been highly detrimental to customers?

A. Absolutely. Less than six months after the Commission re-approved Ameren Missouri's FAC in File No. ER-2012-0166 (which was the first case where the FAC tariff became highly prescriptive and where a change provision was included), MISO changed from a monthly capacity auction to its current annual auction format. Coincident with that change, MISO also implemented a *new charge type* used to settle these capacity transactions. That charge type obviously was not listed in the FAC tariff.

Q. You noted that MISO changed the charge type used to settle capacity when it changed from a monthly auction to an annual auction. What would the impact on customers have been if Ms. Mantle had succeeded in keeping this change provision out of the FAC tariff approved in File No. ER-2012-0166?

A. Without this provision in our FAC tariff, beginning in June 2013, Ameren Missouri would have kept 100% of its net capacity revenues from this new MISO capacity auction. Even if those capacity revenues stayed at the same level as had been assumed when the base for the FAC had been set in that case, customers would have seen higher FAC charges because the offset to net energy costs in the FAC provided by MISO capacity revenues would have completely gone away. Moreover, if capacity revenues had gone up above the base, customers would have missed out on receiving 95% of the increase.

Q. Have you determined what the harm to customers would have been as a result of MISO changing the charge type for capacity transactions if the change provision had been excluded from the FAC?

A. Yes. The Rider FAC tariff from File No. ER-2012-0166 became effective in January 2013 and remained in effect through May 2015. The new charge type became effective in June 2013.

Between June 2013 and May 2014, there would not have been any effect on customers since Ameren Missouri's net capacity revenue under the new MISO charge type was zero – all our excess capacity sales were bilateral (with parties other than MISO), and the new charge type would not have affected inclusion of those revenues in the FAC.

Between June 2014 and May 2015, however, Ameren Missouri had net capacity revenues of $7.3 Million – which was $1.6 million higher than the $5.7 million included in determining the FAC base factors. Of that difference, 95% ($1.5 Million) was credited to customers through the FAC.

If OPC's position had been adopted and the change provision had not existed, all $2.8 million of the net capacity revenues from the MISO capacity auction under the new charge type would have been excluded from the FAC. That would have left only $4.5 million in bilateral capacity sales revenues in the FAC, resulting in a $1.2 million under-recovery as compared to the $5.7 million included in determining the FAC base factors. Of this shortfall, 95% ($1.1 million) would have been recovered from our customers.

The bottom line is, having the change provision in the FAC *in just this one instance* saved our customers over $2.6 million (they received $1.5 million of higher capacity revenues, instead of being charged rates in the FAC reflecting a $1.1 million increase in actual net energy costs).

Q. Ameren Missouri has seen its net capacity revenues increase substantially since then, hasn't it?

A. Yes. For the period of June 2015 through May 2016, a new FAC was in place. During that period, the $49.9 million net capacity revenues under the new charge type would have been included even without the change provision because we had a rate case that concluded in May 2015. Consider, however, what would have happened had we filed that rate case just six months later than we did, delaying the effective date of the tariffs from that case by six months. Had there not been a change provision, customers would have lost almost $25 million of higher net capacity revenues – all because MISO changed the label on preexisting costs and revenues.

Q. Do you have any final observations regarding Ms. Mantle's recommendation regarding such a change provision?

A. Yes. In its Report and Order in File No. EO-2010-0255 (p. 21), the Commission stated that "calling a dog a duck does not make it quack." Similarly, MISO changing a label or re-slicing components of purchased power, off-system sales, or transmission into different charge types does not mean the cost or revenue represented by the new charge type loses its essential character. The capacity example is an apt one. These were capacity costs and revenues before MISO set up charge types labeled "Real-Time Resource Adequacy Auction Amount" and they remained capacity costs and revenues afterward.

VI. BILATERAL CONTRACTS/FINANCIAL SWAPS

Q. What issue do you wish to address regarding the bilateral contracts/financial swaps margins included in the calculation of a base level of off-system sales in this case?

A. I do not entirely agree with Staff witness Erin Maloney's methodology for calculating this margin. Her calculation is shown in her work paper provided with the Staff Cost of Service Report (MaloneyWorkpaperHC_corrected.xlsx). Note that for the purposes of this testimony, it should be understood that the term "bilateral" refers to "physical bilateral transactions," since the "financial swaps" actually include "financial bilateral transactions."

Q. What is your specific disagreement with Ms. Maloney's methodology?

A. I disagree with Ms. Maloney's use of the annual, around-the-clock average of the weighted average hourly energy prices used in the production cost modeling instead of the *actual* costs of these bilateral transactions.

Q. Please explain why you disagree.

A. Bilateral transactions and financial swaps are hedging mechanisms to mitigate some of the volatility from OSSR, but they do not replace the off-system energy sales themselves. Since bilaterals are physical transactions, the energy and the associated fuel has already been accounted for in the production cost model, whether PROSYM or PLEXOS (the model used by Staff). However, these models price the energy at the day-ahead spot market price. A bilateral transaction replaces that price with a fixed price – thus the purpose of the adjustment for these margins is to capture the difference between the spot price and the fixed price.

A review of Ms. Maloney's work paper indicates that she first calculated the net revenue by month for bilateral transactions, subtracting the cost of bilateral purchases from the bilateral sales revenue. She then calculated a cost of these transactions by multiplying the difference between the volumes of bilateral purchases and sales by the normalized, around-the-clock average market price for energy derived from the hourly prices used in the production cost model ("normalized price").

This method of calculation is incorrect. Bilateral transaction margins should be calculated by taking the difference between the actual price received and the price that would have been received had the transaction settled at the spot market for the CPNode specified by the transaction and multiplying that difference by the volume. (For a bilateral purchase, the calculation is reversed – it is a comparison of the fixed price paid to the spot price which would have been paid). While Ms. Maloney's methodology uses the actual price of the bilateral transaction, she has replaced the actual price at which that transaction settled with the normalized price. Using this price creates two issues.

The first issue is that using a normalized price instead of the actual spot market price breaks the relationship between the actual price of the transaction and the actual spot price that would have been received. The two are inextricably linked. The price of a bilateral transaction is based in large part on the counterparty's expectation of what the spot market price will be during the period of delivery. The normalized price is developed using 33 months of data, which is then averaged into on-peak and off-peak prices by month, which are subsequently shaped into hourly prices. There is no correlation between the actual price of our bilaterals and the normalized price for any given hour used in the production cost model.

The second issue is that Ameren Missouri's actual bilateral sales varied in both price and volume throughout the normalization period. They were not at the same volume in every hour of the period. Maloney's use of an annual price does not recognize that fact. Thus, even if it were proper to use normalized prices instead of actual hourly prices, it would be necessary to apply the normalized price for a given hour to the volume of bilateral sales for the same hour, instead of the normalized annual average price. Doing so would require normalizing bilateral sales volumes by hour for each hour of either the true-up period or the test year.

Q. Did you have any additional observations regarding the calculation of bilateral margins?

A. Yes. The first is that Ms. Maloney's calculation used 36 months of data, adjusted for the Polar Vortex. The calculation of bilateral margins included in my direct testimony only covered the 12-month period ending March 31, 2016. Ms. Maloney's use of 36-month of data is consistent with the normalization period used in File No. ER-2014-0258. My calculation of the bilateral margin for the true up period will be corrected to utilize the 36-month period ending December 31, 2016, adjusted for the Polar Vortex. (I would note that this same issue exists for the calculation of financial swap margins, and accordingly, we will adjust that calculation as well).

Additionally, the margin for the transactions with the Missouri municipalities was erroneously included in the bilateral margins in my direct testimony. While these are indeed bilateral transactions, these transactions were specifically included in the production cost model. As such, any margin associated with these contracts has already been accounted for in the production cost model results. Including them in the bilateral margin calculation would be a double-count of the associated margins. These transactions will be excluded from the true-up calculation of bilateral margin. They will be included in the true-up production cost model run.

Q. Do you have a recommendation regarding the calculation of the bilateral margin adjustment to off-system sales revenue to be included in the calculation of off-system sales revenue?

A. Yes. I recommend that this adjustment be calculated using actual bilateral sale and purchase transaction prices and volumes and the corresponding actual spot market prices. I recommend that the calculation utilize 36 months of actual data ending December 31, 2016, adjusted for the Polar Vortex period of January 2014-March 2014.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company	)	
d/b/a Ameren Missouri's Tariffs to	)	File No. ER-2016-
Increase Its Revenues for Electric Service.	)	

AFFIDAVIT OF ANDREW MEYER

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Andrew Meyer, being first duly sworn on his oath, states:

1. My name is Andrew Meyer. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Director, Energy Management & Trading.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 56 pages, and Schedules AM-R1, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Andrew Meyer
Andrew Meyer

Subscribed and sworn to before me this 17th day of January, 2017.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2018
Commission [illegible]

The following is a very simple co-optimization example based on the following assumptions:

- Utility A owns Resource A and Utility B owns Resource B. Both resources are 100 MW generating units capable providing both energy and spinning reserve.
- Utility A's load is 90 MWhs and it has a spinning reserve requirement of 15 MW. The cost of Resource A is $15.
- Utility B's load is 80 MWhs and it has a spinning reserve requirement of 10 MW. The cost of Resource B is $20.
- Any purchase or sale of energy will be at the cost of the seller.
- The price of any spinning reserve purchased or sold is $1/MW

Prior to the establishment of a RTO administered ancillary services market, in a given hour Utility A would dispatch Resource A at a level of 85 MW so that it could meet its 15 MW spinning reserve requirement. This would require it to purchase 5 MWhs of energy from Utility B to meet its load in that hour. Utility B would also dispatch Resource B at 85 MW which is equal to Utility B's load plus the 5 MWhs sold to Utility A leaving 10MW to meet its 10 MW spinning reserve requirement. The table below summarizes the hour just described:

Gen MWh	*Fuel Cost*	*Pur/(Sale) $ Energy*	*Pur/(Sale) $ Spin*	*Net*
A 85	$1,275	$100		$1,375
B 85	$1,700	($100)		$1,600
170	$2,975	$ -	$ -	$2,975

As shown in the table above, Utility A would have a fuel cost of $1,275 and a purchased power cost of $100 for a net fuel and purchased power cost of $1,375. Utility B would have fuel costs of $1,700 and off-system sales revenues of $100 for a net fuel and purchased power cost of

$1,600. The net system cost combining Utility A and B's operations in that hour would be $2,975.

With the establishment of a RTO administered ancillary services market, it would be expected that the total spinning reserve requirement would drop. As an example, using the same Utility A and B described above, assume that the total spinning reserve requirement becomes 20 MW instead of the combined 25 MW under the prior system, with Utility A's requirement being 12 MW and Utility B's requirement being 8 MW.

Utility A's generation would now be dispatched by the market at its full 100 MW as it is the cheapest resource to provide energy. Utility A would purchase all 12 MW of its spinning reserve requirement and have a 10 MWh net sale of energy.

Utility B's generation would be dispatched at 70 MWs. The full 20 MWs of spinning reserve would be provided by Utility B's unit. Utility B would have a net purchase of 10 MWh and it would have a net sale of spinning reserve of 12 MWs. The table below summarizes the hour just described:

	Gen MWh	*Fuel Cost*	*Pur/(Sale) $ Energy*	*Pur/(Sale) $ Spin*	*Net*
A	100	$1,500	($200)	$12	$1,312
B	70	$1,400	$200	($12)	$1,588
	170	$2,900	$ -	$ -	$2,900

As illustrated in the table above, Utility A would now have higher fuel costs and would also now have purchased power costs for acquiring spinning reserve, but those increases are more than offset by the revenues received from selling energy that was previously held back to self-provide spinning reserve. Utility A's net cost dropped from $1,375 to $1,312. Utility B's fuel costs have also fallen significantly and it now receives ancillary services revenues above its ancillary services purchases. This net reduction in cost is partially offset by the cost of the energy that it now purchases. In total, however, its net cost has also been reduced to $1,588 from $1,600. Thus, the co-optimized RTO markets resulted in an overall cost reduction for Utility A and B in this one hour of $75. Simply stated, the co-optimization allowed Utility A's cheaper unit to be dispatched to its full potential instead of having to be held back to provide spinning reserves while Utility B's unit, more efficiently provide the spinning reserves (by producing less energy since it is a higher cost unit).