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Witness: Jaime Haro
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2014-0258

REBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January, 2015

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REBUTTAL TESTIMONY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jaime Haro. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom are you employed and in what capacity?

A. I am Senior Director, Asset Management and Trading for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Are you the same Jaime Haro who filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to address (a) the common argument made by Staff witness Erin L. Maloney and Missouri Industrial Energy Consumers ("MIEC") witness Nicholas L. Phillips in support of including margins from bilateral and financial swap transactions in the Net Base Energy Cost ("NBEC") against which changes are tracked in the Company's fuel adjustment clause ("FAC") (I will also address a separate load and generation forecasting deviation adjustment proposed by Mr. Phillips alone); (b) Mr. Phillips' proposal to expand the "Polar Vortex" adjustments to natural gas and spot future prices, and to Midcontinent Independent System Operator, Inc. ("MISO") Market Settlement Charge Types; (c) Sierra Club witness Ezra D.

Hausman's idea to remove the "must-run" status of the Company's coal-fired units when modeling offers into the MISO market; (d) Office of Public Counsel ("OPC") witness Lena Mantle's claims regarding the volatility/uncertainty of various FAC components; and (e) MIEC witness James Dauphinais' recommendation that certain transmission charges and revenues should be removed from the FAC.

II. PROPOSED ADJUSTMENTS FOR BILATERAL TRANSACTIONS AND FINANCIAL SWAPS

Q. What are the components of net off-system sales revenues?

A. As noted in my direct testimony, our proposed net off-system sales revenues are comprised of the following components:

1) net energy sales revenues (obtained from the PROSYM model results sponsored by Ameren Missouri witness Mark Peters in his direct testimony);

2) capacity sales revenues;

3) ancillary services revenues;

4) real time RSG MWP[1] margins; and

5) other miscellaneous MISO revenues.

Q. Have other parties recommended adjustments to this list?

A. Yes. MIEC witness Nicholas Phillips proposes to include an adjustment for normalized real time load and generation deviations as well as for normalized financial swap and bilateral margins. Staff Witness Erin Maloney has also proposed an adjustment for normalized swap and bilateral margins.

Q. What is your understanding of the purpose of these proposed adjustments?

[1] Revenue Sufficiency Guarantee Make Whole Payments.

A. It is my understanding that the proponents of these adjustments contend that making the adjustments will incrementally improve the calculation of NBEC, by accounting for certain factors which by their nature cannot be accounted for in the PROSYM model results.

Q. Are there other adjustments to the PROSYM model results which are made for arguably the same purpose?

A. Yes. In terms of net OSSR,[2] the PROSYM model outputs net sales and purchases of energy at a spot price. It does not account for ancillary service revenues, capacity revenues, real time RSG-MWP margins, or miscellaneous MISO revenues. All four of these items are accounted for outside of the model with adjustments that have been included since the inception of the FAC. Each of these adjustments is made to account for a source of revenue not captured in the PROSYM model, and thus to incrementally improve the accuracy of the NBEC calculation.

Q. If there are other adjustments which are made outside of the model, does that necessarily mean any adjustment that is purported to incrementally improve the calculation of NBEC should be included?

A. No. It would be inappropriate to adjust NBEC simply based on an assertion that the model does not account for a particular source of potential revenue. Such adjustments should only be made if it can be demonstrated that not only does the model not account for such revenues, but that the source of the revenues can reasonably be expected to continue into the future and the inclusion of the adjustment is reasonably expected to improve the accuracy of the NBEC calculation.

[2] Off-system sales revenues, as defined in the Company's FAC tariff in Factor OSSR.

Q. Do Mr. Phillips' and Ms. Maloney's proposed adjustments meet this threshold?

A. I believe that it is reasonable to assert that the PROSYM model does not account for these adjustments and that the factors giving rise to the adjustments are expected to continue into the future. I am less certain that the inclusion of these adjustments can be expected to consistently or reliably improve the accuracy of the NBEC, a point which I also discussed in my rebuttal testimony in File No. ER-2012-0166.

Q. Can you please elaborate on these points?

A. Yes. The PROSYM model optimizes and essentially presumes a perfect dispatch of Ameren Missouri's generating resources, given a set of operating characteristics, fuel prices, and energy prices. Since Ameren Missouri clears the overwhelming majority of the megawatt-hours it sells from its generation and the megawatt-hours it buys for its load in the day-ahead market, the model utilizes an energy price input assumption based on day-ahead prices.

The model neither accounts for operating conditions which vary from "perfect," nor does it account for sales which are priced at other than a day-ahead spot price. The existing adjustment for real time RSG-MWP margins and Mr. Phillips' proposed adjustment for real time load and generation deviations attempt to account for revenues arising from imperfect operating conditions, while the proposed adjustment from MIEC and Staff for bilateral and swap margins seeks to account for revenues arising from prices other than those established by the day-ahead spot market.

I am certain that we will continue to experience operational impacts which reflect the imperfect reality in the operation of the system and markets. I am also certain that as long as Ameren Missouri continues to seek to hedge a portion of the price exposure for its future net off-system sales, we will also continue to see transactions which are priced at other than the day-ahead spot market price.

What I am not certain of is whether these differences will remain at a stable level, or even consistently represent incremental revenue as opposed to incremental cost. This is why it is not clear that including the adjustments recommended by Mr. Phillips and Ms. Maloney will actually consistently improve the accuracy of the NBEC calculation, and it is why I did not include them in my direct testimony.

Q. Is Ameren Missouri nevertheless willing to include these proposed adjustments in the calculation of the NBEC?

A. While it is not clear that these meet all of the criteria I outlined above for inclusion, it is also difficult to establish that the criteria are not met. Therefore, Ameren Missouri is willing to include an adjustment for these items, conditioned upon the following:

1) Either all of the following adjustments should be included in the NBEC or none of them should be included: real time RSG-MWP margins, real time load and generation deviations and bilateral and swap margins. If we (Staff, MIEC, and the Company) are going to conclude that it's more probable than not that including these kinds of items better fulfills the spirit of "perfecting" the estimation of OSSR in the NBEC, then all such items should be included rather than picking and choosing only some of such items.

2) The calculation of these adjustments must be corrected as discussed below and in Ameren Missouri witness Mr. Peters' rebuttal testimony. Mr. Peters discusses needed corrections to the calculation of the real time RSG-MWP margin

and real time load and generation deviation adjustments. The bilateral and swap margin calculation must also be corrected, as I discuss below.

3) The value for all of these adjustments should be determined as of the end of the true-up period (December 31, 2014), and also reflect a consistent treatment of the Polar Vortex anomaly.

Q. Have you calculated an interim value for the bilateral and swap margins?

A. Yes. I have calculated a normalized value through the true-up period of $1.1 million for bilateral margins and $3.2 million for financial swaps, for a total of $4.3 million.

Q. You indicated above that a correction to the calculation of this proposed adjustment was required. Can you please discuss what corrections are needed?

A. Yes. While I generally agree with the methodology used by Mr. Phillips to calculate his adjustment, I disagree with Ms. Maloney's methodology for calculating the bilateral margin portion of her adjustment – in large part because Ms. Maloney did not actually calculate a bilateral *margin*, but rather, she calculated a level of normalized bilateral *revenue*. (For the purpose 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. Please explain why Ms. Maloney did not calculate a bilateral margin.

A. Because Ms. Maloney failed to utilize the actual prices at which these transactions were made and she also failed to account for the costs that are necessarily incurred to complete these transactions.

Q. Please expand on your first point.

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 PROSYM computes the revenues and the fuel cost for the off-system energy sales, the bilateral transactions and financial swaps should be calculated as a margin derived from the difference between the sales price and the settling index.

Since these bilaterals are physical transactions, the energy and the associated fuel has already been accounted for in the production cost model, whether PROSYM or REAL TIME (the model used by Staff and MIEC). However, the models price the energy at the day-ahead spot market price. Ms. Maloney first calculated a normalized annual volume of bilateral sales, net of bilateral purchases – energy which is already accounted for in the model. She then multiplied this volume not by the difference between the price that Ameren Missouri would have received from the spot market (absent the bilateral transaction) and the actual transaction price (the margin), but rather by the simple annual average market price for energy that she calculated as an input into Staff's REAL TIME production cost model. Setting aside Ameren Missouri's disagreement with Staff's methodology for calculating the average market price for energy as discussed by Mr. Peters in his rebuttal testimony, what Ms. Maloney has done is to calculate the spot market revenue that the normalized amount of bilateral transactions would receive, if they were evenly distributed across the entire year (same amount in each hour). However, since the energy is already accounted for in the production cost model, she is double-counting the sales revenue, in addition to misapplying the price.

Q. How should the bilateral margin be calculated?

A. At its core, the calculation for the bilateral margin is not materially different from that for the financial swap margin. The margin is 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[3] 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.)

Q. Did Mr. Phillips use the same methodology as you did?

A. Yes, he did.

Q. You indicated that all adjustments should reflect a consistent treatment of the Polar Vortex anomaly. What should that treatment be?

A. For those adjustments using 12 months of historical data, I support Mr. Phillips' approach of excluding data for the months of January, February, and March of 2014 from the true-up period and annualizing the values from the remaining nine months. For those adjustments using 36 months of historical data, I support the methodology Ameren Missouri and Mr. Phillips utilized for adjusting energy prices – that is the market prices for the period of January 1, 2014 – March 31, 2014 have been replaced with the average prices for the applicable peak period by month, from the prior two years, January 2012 – March 2012, and January 2013 – March 2013. (I would note here that my direct testimony inadvertently indicated that only data from January 2012 – March 2012 was used as a replacement. I have confirmed that the actual calculation did indeed include both years' data as noted by Mr. Phillips).

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[3] Commercial Pricing Node (CPNode) is used by the MISO as the location (or a collection of locations) at which market activities, including load and generation, are measured and settled. The MISO publishes

III. EXPANDED ADJUSTMENTS FOR POLAR VORTEX

Q. Mr. Phillips states in his direct testimony that wholesale electric energy prices are not the only costs highly sensitive to the Polar Vortex and proposes that both natural gas price assumptions and MISO Market Settlement Charge Types should be adjusted to account for the Polar Vortex. Do you agree?

A. Yes. These are appropriate adjustments.

The natural gas price assumptions utilized in the true-up period run should be developed in a manner similar to that utilized to develop the market price of energy for the model – that is, the values for each month in the period of January 1, 2014 – March 31, 2014, should be replaced with the average value for that same month from the two prior years.

MISO Market Settlement Charge Types should be adjusted using the methodology proposed by Mr. Phillips using the values for the true-up period ending December 31, 2014.

IV. COMMITMENT STATUS: "MUST-RUN" VS "ECONOMIC" OF COAL-FIRED GENERATION

Q. Can you explain what the terms "Must-Run" and "Economic" refer to in the context of "Commit Status" within the MISO offers?

A. Yes. When a generation owner offers a unit into the MISO market, it can choose among several "commitment status" options. Two of these options are "Must-Run" and "Economic." The Must-Run status tells the model utilized by MISO as part of the process of dispatching units in its footprint that the unit will run despite any margin calculation that the model performs, whereas the Economic status allows the MISO

locational marginal prices ("LMPs") (both day-ahead and real time) for each CPNode.

model to de-commit (issue a stop order for) a generator when the revenues generated are lower than the offered costs.

Q. Why would the Company offer its coal units to the MISO market under an Economic status versus a Must-Run status?

A. In general, the Company wants the units clearing in the market when they are profitable and benefitting ratepayers. The vast majority of the time, due to the relatively low cost of these specific Ameren Missouri coal-fired generators, these units would clear in the day-ahead market whether they are offered as Economic or as Must-Run. There are times when a given unit would not clear in the day-ahead market, as the margin between the LMP[4] revenue and the as-offered cost for that 24-hour market clearing period becomes negative. As discussed below, however, merely looking at one 24-hour period is not appropriate. The Company must look past that time period and see if this negative margin condition is projected to exist for a prolonged period of time.

Q. Dr. Hausman claims that using a Must-Run commit status "results in a departure from short-run, least-cost dispatch, and thus increases overall production cost." Do you agree?

A. No. Dr. Hausman fails to account for the limitations of the MISO methodology and the role that unit startup costs play in overall production cost. As I will demonstrate below, the use of an Economic commit status in MISO market methodology can actually increase overall production cost, while the use of the Must-Run can decrease overall production cost.

[4] The LMP is the wholesale price of energy established in the MISO market.

Q. Please explain the limitation of the MISO methodology.

A. There are several reasons, including operational reasons which are addressed in the rebuttal testimony of Ameren Missouri witness Chris Iselin, which support Ameren Missouri utilizing a Must-Run commit status. These operational considerations are particularly noteworthy when we acknowledge the significant limitation in the algorithm utilized by MISO in dispatching generators in its footprint. As detailed in MISO Business Practices Manual ("BPM") 002, Energy and Operating Reserve Markets, the model will only optimize the commitment of a resource within a very narrow 24-hour window; that is, for the next calendar day. In doing so, MISO's model does not take into consideration the market's expectation of future market prices or the cost of restarting the generator after it had determined that a generator should be turned off. While it does consider whether a unit has met its minimum up time requirement before de-committing a unit, it does not take into consideration that this same unit's minimum down time and/or startup costs may make it unavailable for commitment for the following market day (two days into the future) during a period when it would be profitable to operate.

The Company is not hampered by these time restrictions, however, and can make a decision based on the review of data over a much longer period of time.

Q. Can you provide an example of how the MISO methodology increases net cost for Ameren Missouri?

A. Yes. Consider the example where a generating unit's as-offered production cost for a calendar day is less than the revenue it would receive from the MISO market resulting in a total "loss" for the day of $1,200 if it were Must-Run. If, however, the unit commit status was Economic and we were to rely on the MISO model's algorithm, this unit would not run on that day and that “loss” would be avoided.

On day two, market prices rise such that the difference between the as-offered cost, not including a startup cost of $100,000, and the revenue from being cleared is $10,000. The MISO methodology will not start the unit as it cannot cover the startup cost that would now have to be incurred since the unit was turned off the day before, so it remains offline even though it would make money that day had it been running.

On day three, this difference rises to $110,000, and the unit clears in the market and is dispatched to run.

The margin for these three days totals $10,000. Days one and two have zero margin as the unit did not run, while the margin on Day three was $10,000 after subtracting the $100,000 cost to start the unit.

Had the unit been Must-Run, the total margin for these three days would have been $118,800. On day one, there would have been a $1,200 loss, on day two a $10,000 gain, and $110,000 gain on day three. Since the unit never came off line, there would not have been a startup charge.

In this simple example, the increase in net energy cost for just those three days from letting the MISO methodology dispatch the unit would be $108,800.

If we consider that the MISO methodology would never restart the unit until it overcame the $100,000 startup cost, the avoidable loss could be extreme. The worst case scenario would be a situation where future daily margins remain just under the $100,000 amount for a protracted period of time. If potential margins averaged $75,000 a day for the next 30 days, but never exceeded $100,000, the avoidable loss would be over $2 million from not offering the unit as Must-Run.

Q. How can these kinds of lost opportunities be prevented?

A. The best way is to designate the unit as Must-Run, which prevents the MISO algorithm from de-committing it.

Q. Are there other reasons why 24 hours is an inappropriate time period for considering whether or not to de-commit a coal-fired generation resource?

A. Yes. First, different units have varying minimum up and down times. As noted above, Mr. Iselin's testimony discusses operational considerations for these units which restrict our ability to cycle them on and off in 24-hour periods. Those considerations, in combination with the limitations of the MISO market clearing process (most importantly its failure to consider the cost to restart a unit when not clearing it in the day ahead market), are why the Company does not leave the commitment of these units to the MISO process, and instead considers a multi-day period when reviewing the possibility of taking a unit off line for economics.

Q. Dr. Hausman suggests that the Company should model **[redacted] with an Economic status as opposed to Must-Run. Do you agree?**

A. No. Ameren Missouri witness Mark Peters addresses this issue in his rebuttal testimony, where he quotes the Company's response to Data Request SC-008, which read in part as follows: "**[redacted]** remain must run units in actual operations due to their operating characteristics, high cost to restart and expected increase in forced outages due to unit cycling. As such, it would be neither meaningful, nor appropriate to model them in a manner that differs from expected operations." The point is that when we model the units for a rate case, the goal is to model them *as they are expected to operate in the market*.

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Q. Dr. Hausman claims that "… changing the commit status of **[redacted]** **[would] affect the Company's projected and actual off-system sales…" Do you agree?**

A. No. For sales to be affected, these units would need to experience prolonged periods where they were not profitable – in excess of the cost of restarting them. Considering that the startup costs for a Labadie or Rush Island unit is approximately **[redacted]**, this is no small consideration. The Company has not experienced, and does not expect to experience, those conditions. In all of 2014, there was not a single instance when the average day-ahead LMP for a consecutive five-day period would have warranted decommitting a **[redacted]** generating unit. Put another way, the actual history shows that these units in fact will run and should be running. But if we leave those "decisions" to the MISO model, the Company risks losing significant margins that it should otherwise realize, because as the example outlined earlier explains, the MISO model cannot account for more than one day at a time and cannot account for start-up costs. These limitations can lead it to making the wrong decision. Customers would be harmed if we were to allow it to do so.

IV. FUEL ADJUSTMENT CLAUSE

A. Transmission Charges and Revenues.

Q. MIEC witness James R. Dauphinais argues that transmission charges associated with off-system sales should be removed from the FAC. Do you agree?

A. No, and it bears noting that Mr. Dauphinais himself has explicitly stated in the past – in sworn testimony – that these charges properly belong in the FAC, as they have been since the inception of the FAC in March 2009.

Q. Please elaborate.

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A. In the Company's last rate case, File No. ER-2012-0166, Mr. Dauphinais argued that certain transmission charges (charged by MISO for power used to serve the Company's load) were ineligible for inclusion in the FAC due to the terms of the FAC tariff that was then in effect. In support of his argument, he claimed that the then-effective FAC tariff provision required exclusion of these charges because it contained the following provision: "…excluding capacity charges for contracts with terms in excess of one (1) year incurred to support sales to all Missouri retail electric generations."[5] The Commission Staff disagreed that the "capacity" charges referred to in this section of the tariff referred to "transmission capacity," and pointed out that the reference was to generation capacity. The Commission agreed, stating that "the tariff's exclusion of capacity charges for contracts with terms in excess of one year refers to generation capacity, not transmission capacity."[6] As noted, Mr. Dauphinais' argument at the time was focused on transmission charges for power used to serve our load, but in his surrebuttal testimony, when discussing off-system sales, he made at least three statements that transmission charges associated with off-system sales *are* appropriately recovered in the Company's FAC. All of those sworn statements are at odds with his new position in this case.

Q. Where did he make those statements?

A. The first such statement is found on page 13 of that surrebuttal testimony, where in his response to the question of "what transmission expenses may the Company include in its FAC", he stated: "These are incremental transmission charges that the Company would not incur for reasons other than to make certain power purchases and

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[5] Ex. 518, File No. ER-2012-0166 (Dauphinais Surrebuttal), pp. 13-14.
[6] *Report and Order*, File No. ER-2012-0166, p. 85.

off-system sales on behalf of its retail customers. As such, they are appropriately recovered in the Company's FAC and included in the Company's NBFC value."[7] Now, in this case, he claims that the very same "incremental transmission charges . . . to make . . . off-system sales . . ." should be excluded.

The second instance is found on page 14 of his surrebuttal testimony, where he testified that "MISO transmission charges associated with the short-term transmission service necessary to support power purchases or off-system sales are incremental costs directly related to the Company's fuel and purchased power cost less off-system sales margins to which the Company attributes much of the cost savings that has come from MISO participation."[8] Again, he supported including those transmission charges in the FAC, but now he has reversed course.

The third instance is found of page 16 of his surrebuttal testimony. When asked if he objected to the inclusion of certain transmission charges to "support the Company's off-system sales to entities not located in MISO and PJM in its FAC and NBFC," he stated "No. Provided they are prudently incurred, those particular MISO Schedule 26 and 26-A charges are appropriately recoverable through the Company's FAC. They are incremental charges directly associated with the Company's fuel and purchased power costs less off-system sales revenues."[9] This, too, reflects a position totally opposite to his current position regarding transmission charges associated with off-system sales.

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[7] Ex. 518, File No. ER-2012-0166, p. 13, l. 18-22.
[8] *Id.*, p. 14, l. 15-19.
[9] *Id.*, p. 16, l. 6-9.

Put another way, under Mr. Dauphinais' new position, the off-system sales revenues would be credited to customers (100% of them in base rates and 95% of the changes through the FAC), but the transmission charges associated with them would be mis-matched and outside the FAC. This is inappropriate.

Q. So is it your position that these transmission charges for off-system sales belong in the FAC?

A. Yes, as they have been since the inception of the FAC. Our position on this has never changed. Mr. Dauphinais was right when he previously testified that these are incremental transmission charges that the Company would not incur for reasons other than to make certain off-system sales on behalf of its retail customers.

Q. Having addressed transmission charges associated with off-system sales, can you please describe Mr. Dauphinais' position about transmission charges for purchased power?

A. Mr. Dauphinais claims that the vast majority of the transmission charges that Ameren Missouri is assessed by the MISO should be excluded from the FAC by claiming that these are not charges associated with purchased power, but rather, that they are simply associated with the transmission of energy from Ameren Missouri’s own generators to its own retail load. I disagree.

Q. Please explain why you disagree.

A. First of all, these charges have been in the FAC since its inception, nearly six years ago. The Commission itself has recognized that this is proper, as reflected in its *Report and Order* in our last rate case.[10] Second, Mr. Dauphinais’ argument ignores the

[10] Report and Order, File No. ER-2012-0166, pp. 84-85.

reality of how megawatt-hours are sold and purchased in the MISO market. As a function of the MISO markets, Ameren Missouri purchases all of the megawatt-hours used to serve its load requirement from the MISO market. The Commission recognized this reality in its *Report and Order* in our last rate case, stating that "Ameren Missouri has access to a transparent energy market where it can acquire power to serve its load and sell power off-system."[11] Except for megawatt-hours sold pursuant to physical bilateral contracts with those outside MISO, Ameren Missouri sells all of the megawatt-hours it generates to the MISO market. As I explained in the Company's last rate case, the MISO market operates like a large pool of water – all of the water (power) that is produced/sold is poured into the pool and then the utility draws water (power) from that pool to serve its customers (i.e., its load). The transmission charges Mr. Dauphinais wants to exclude would not be incurred by Ameren Missouri but for the fact that they are assessed on every megawatt-hour that Ameren Missouri buys from the MISO market (put another way, for every megawatt-hour Ameren Missouri draws from the MISO pool). The Commission also recognized this in our last case: "As part of its membership in MISO, Ameren Missouri incurs certain transmission charges for the load it serves through the MISO market."[12]

Q. Can you please provide some background on Ameren Missouri's participation in MISO?

A. Yes. FERC Order 888 (issued in 1996) and FERC Order 2000 (issued in 2000) set FERC policy to encourage utilities to participate in RTOs. Those orders provide the underpinnings of the current open access transmission and led to the

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[11] *Report* and Order, File No. ER-2012-0166, pp. 84-85.
[12] *Id.*, p. 83.

development of transparent wholesale energy (and related) markets, such as those operated by MISO since 2005. With this Commission's permission, Ameren Missouri joined MISO in 2003 based on a cost-benefit study that showed that customers were better off with Ameren Missouri in MISO. The Commission has twice since extended Ameren Missouri's participation in MISO, also based upon cost-benefit study results indicating that MISO participation is beneficial, meaning that MISO-related benefits outweigh MISO-related costs.[13] Ameren Missouri will be filing additional cost-benefit studies in 2017 when the Commission will again examine its RTO participation.

Q. In the Company's last rate case, the Commission determined that these transmission charges are large, that Ameren Missouri has little control over them, and that they are volatile because no one knows for sure how much the MVP projects will cost once construction is complete (*Report and Order,* File No. ER-2012-0166, p. 88). Are those findings still correct?

A. Yes, they are. As Mr. Dauphinais himself recognizes, transmission charges in total are now about $30 million annually, and are currently projected to more than double (to about **[redacted]** annually) in the next five to six years. I have also illustrated this using the normalized loads provided by Ameren Missouri witness Steve Wills in connection with his direct testimony, and the projected rates for MISO Schedule 26A included in Mr. Dauphinais' testimony, which I have used to calculate a projected total for these charges for the next few years. As the table shows, Ameren Missouri's transmission charges from MISO (there are others, but this captures the largest

[13] As the Commission recognized in its last order continuing its permission for Ameren Missouri to participate in MISO, the last study indicated there were $105 million of net benefits over the three-year study period. *Report and Order*, File No. EO-2011-0128, p. 7.

source of the increase, Schedule 26A) can be expected to increase from more than **[redacted]** in 2015 to over **[redacted]** in 2018. I would note, however, that these figures (and those Mr. Dauphinais relies upon) are estimates provided by the MISO and as such are, uncertain – they could be materially higher or lower as they largely depend on transmission construction that has not yet occurred and which could cost materially more or less than currently estimated, a fact that the Commission itself recognized in its order in our prior rate case.

[redacted]

Q. Mr. Dauphinais seems to rely on the fact that MISO nets purchases from the market against revenues received for sales to the MISO market from Ameren Missouri's generating units when invoicing the Company for all of the charges the Company incurs from MISO. Does this netting negate the fact that Ameren Missouri purchases all of the megawatt-hours used to serve its load from the MISO market?

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A. No, it does not. As I explain below, MISO's settlement statements, tariff[14] and BPMs[15] all recognize that the megawatt-hours generated from our plants are sold to the market and that megawatt-hours are purchased from the market to serve our load. That for billing and financial reporting purposes the sums are netted is irrelevant to the operation of the market.

Q. Does Mr. Dauphinais provide testimony that supports the conclusion that Ameren Missouri buys all of its megawatt-hours to serve its load from the MISO market?

A. Yes. Mr. Dauphinais testifies on page 9 of his direct testimony that "In each operating hour, Ameren Missouri offers energy production from all of its generation facilities into the MISO market and clears all of its load in the MISO market." In laymen's terms, to "clear" your load is to purchase energy to serve your load.

Q. Mr. Dauphinais also testified that "(o)nly in an hour when Ameren Missouri clears less generation MWh than load MWh does Ameren Missouri purchase any power from MISO…" Is this statement correct?

A. No. Mr. Dauphinais is either confusing or ignoring the difference between gross purchases and netting for settlements and reporting.

Q. Mr. Dauphinais points to one of Ameren Missouri witness Mark J. Peters' workpapers as identifying Ameren Missouri's level of purchased power. Does that workpaper indeed identify Ameren Missouri's total purchased power?

[14] MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff is approved by the Federal Energy Regulatory Commission and is binding on market participants in the MISO market, such as the Company.
[15] MISO issues Business Practice Manuals ("BPMs") which provide details about market operations that are not set forth in full in MISO's tariff. MISO's tariff refers to the BPMs for those details.

A. No. Mr. Dauphinais has ignored that the amount listed as purchased power in that workpaper represents a *net* amount. As Mr. Peters stated in his direct testimony, "Ameren Missouri is a market participant within the Midcontinent Independent System Operator, Inc.'s ('MISO') markets. We purchase energy to serve our entire load from the MISO market and separately sell all of our generation output into the MISO market. For modeling purposes, however, we report only on a net basis…"

This netting is done as a matter of convenience, as it would otherwise require the production cost model to be run twice to obtain the same result. The production cost model could be run once with load and no generation to determine the amount of energy purchased from the market to serve load, and a second time with generation and no load to determine the amount of energy sold to the market. The hourly results of the two runs could then be netted together to obtain a net output which could be compared to the financial reporting amounts, which per FERC reporting requirements are netted.

Q. If Ameren Missouri does indeed purchase its entire load requirement from the MISO market, would Mr. Dauphinais' own argument support the inclusion of the associated transmission charges in the FAC?

A. Yes. Mr. Dauphinais testified that "(o)nly Ameren Missouri's wholesale transmission expenses that are incurred to **transmit electric power it has purchased from MISO** or other third-parties (i.e., Purchased Power) should be includable in Ameren Missouri's FAC as they are the only transportation costs for purchased power that Ameren Missouri incurs." (emphasis added). As I have explained, his contention that only the "net" purchases are "purchased power" is wrong because we purchase all of the power and we incur transportation charges on all of the power. His statement that transmission charges for power purchased from MISO should be recovered through the FAC is correct.

Q. Has Mr. Dauphinais provided testimony in other proceedings which demonstrate that Ameren Missouri in fact does purchase all of the power needed to serve its purchases its load requirement from the MISO market?

A. Yes. Mr. Dauphinais provided direct testimony in support of Noranda's rate shift complaint (File No. EC-2014-0224). Beginning on page 4 of that testimony, Mr. Dauphinais stated *"As a participant in the MISO Regional Transmission Organization ('RTO'), Ameren Missouri must clear all of its generation and all of its load in the MISO market."* He went on to state *"the reduction in Ameren Missouri's ANEC can be reasonably and conservatively estimated as the cost avoided by Ameren Missouri by not having to clear the Noranda retail sales in its MISO market and transmission settlements for its load."* (ANEC is Actual Net Energy Cost).

In that same testimony, Mr. Dauphinais provides several examples to demonstrate how an avoided cost would be calculated, including a description beginning on page 6 of what would happen if a utility were to experience 100 megawatt-hour lower retail sales in an hour, with generation output unchanged. He properly notes in this instance that *"(t)he only thing that would change is that the utility will clear 900 MWh of retail load rather than 1,000 MWh of retail load in the RTO market. The utility will continue to have no net purchased energy cost, but will now have a 100 MWh net off-system energy sale because in this hour it is clearing 1,000 MWh of generation but only clearing 900 MWh of retail load."* In the following question, Mr. Dauphinais was asked if net fuel cost savings always appear as an increase in off-system energy sales margins. His response was:

> *In my example, off-system energy sales increased by 100 MWh. If the same retail sales reduction in another hour decreased the utility's net purchase of energy by 100 MWh, the net fuel cost savings would appear in the utility's accounting as a reduction in the utility's net purchased energy costs rather than an increase in the utility's off-system energy sales.*

Q. Please describe the significance of these three sections of Mr. Dauphinais' testimony in File No. EC-2014-0224.

A. These sections of his testimony are significant as they acknowledge that Ameren Missouri clears (i.e., buys power for) *all* of its load in the MISO market, and that a reduction in an actual purchase can be represented by a reported increase in net-off system sales revenue or net purchased energy costs. Regardless of whether the change is reported as a net increase in off-system sales or a reduction in net purchased energy/power costs, the cause of the change is a reduction in *gross* purchased power from the MISO. There could not be a reduction in gross purchased power if the power was never purchased in the first place.

Q. Does the MISO itself provide guidance on this question?

A. Yes, both its Energy Markets Tariff ("EMT") and the MISO BPMs, which contain additional details about the market's operation, reflect the reality that Ameren Missouri purchases all of the megawatt-hours needed to serve its load from the MISO market. For example, the very definition of the term "Bid" in the MISO tariff begins, "A request to **<u>purchase Energy</u>** in the Day Ahead Energy and Operating Reserve Market" (emphasis added). Similarly, the definition of Offer begins, "An offer, that is duly submitted to the Transmission Provider consistent with this Tariff and the Business Practices Manuals, to (a) sell Energy and Operating Reserve in the Energy and Operating Reserve Markets at a specified price, location, quantity, and time period and shall include (i) Generation Offers." The EMT also establishes MISO as the Energy Market

Counterparty, which is defined as "The Transmission Provider as the contracting counterparty to Market Participants for all Market Activities contemplated by this Tariff, solely in the Transmission Provider's capacity as a principal and not as an agent for any other party, consistent with the provisions of Section 6A."

The definitions in the EMT for Day Ahead Energy and Operating Reserve Market, Energy Offer, Fixed Demand Bid, Generation Offer, Offer, Real-Time Energy Purchases, and Real-Time Energy and Operating Reserve Market, among others, consistently recognize the sales we make to the market and the purchases (for all of our load) we make from the market, while Section 6a of the tariff reinforces that MISO "is the contracting party with Market Participants for Market Activities, and collects and distributes all charges for Market Activities." Those definitions are included in Schedule JH-R1.

The MISO Energy and Operating Reserve Markets BPM also describes the operation of the MISO market, and confirms that Ameren Missouri purchases its load from the MISO.

For example, consider the definition of Fixed Demand Bid from the EMT and the discussion of Demand Bids in part 4.3 of the BPM.

> *Fixed Demand Bid: A request to* ***purchase a specified MWh quantity of Energy****, at specified locations in the Transmission Provider Region, during specific Hours of the next Operating Day submitted to the Day-Ahead Energy and Operating Reserve Market. Demand Bids may only be submitted by a Market Participant that is itself a Load Serving Entity (LSE) or is purchasing Energy to serve an LSE.* (emphasis added).

Part 4.3 Demand Bids of the BPM states (emphasis added):

> *Demand Bids apply to the Day-Ahead Energy and Operating Reserve Market only and represent a financially binding Bid to* ***purchase Energy***

at Day-Ahead prices for Real-Time consumption in the next Operating Day. (emphasis added).

Q. Does Ameren Missouri submit demand bids to the MISO?

A. Yes. Ameren Missouri submits a Fixed Demand Bid to the MISO every day for its entire forecasted demand – for all of the megawatt-hours it forecasts are needed to serve its load – not just for the difference between its forecasted demand and some projection of the amount of load it expects to have. As such, when Ameren Missouri's load clears in the Day Ahead market, it has a binding requirement to purchase the entire sum of Energy that it bid for – to purchase ALL of the megawatt-hours, not just some net amount.

Q. Are there other BPM's which demonstrate that load is purchased?

A. Yes. Another MISO BPM is the Market Settlements Business Practices Manual. Section 2.1.2 of this BPM is titled Settling and Invoicing the Financial Transmission Right, Day-Ahead and Real-Time Energy and Operating Reserve Markets. This section includes the following descriptions (emphasis added):

> *Day-Ahead Energy and Operating Reserve Market Settlements – In the settlement of the Day-Ahead Energy and Operating Reserve Market, **each MP that purchased energy** is charged the Day-Ahead LMP applicable at the relevant Commercial Pricing Node (CPNode) **for the quantity (in MWh) of energy scheduled and/or cleared.***
> *Real-Time Energy and Operating Reserve Market Settlements – In the settlement of the Real-Time Energy and Operating Reserve Market, **each MP is settled for Energy based upon the incremental difference between its real-time energy transactions and its day-ahead scheduled energy transactions** multiplied by the applicable Real-Time LMP.* (emphasis added).

Q. Does Ameren Missouri receive settlement statements from the MISO?

A. Yes.

Q. What do these settlement statements show for the amounts purchased from the MISO to serve load?

A. The MISO settlement charge types which represent the amount of energy purchased or sold to the MISO are Day-Ahead Asset Energy Amount and Real Time Asset Energy Amount. Schedule JH-R2 to my testimony is a single day excerpt from a MISO settlement report for day-ahead asset energy amount for both generation and load, produced from nMarket, which is a software program used by Ameren Missouri in part to track MISO settlement statements so that we can "shadow" settle their invoices. nMarket imports data directly from the MISO settlement statement.

The asset owner UEGEN represents our generation, while asset owner UELSE represents our load. As the report clearly shows, in each hour of the day, there is an amount in the VAL column (which represents the settlement amount) for both the load and the generation. The generation value is a credit for the revenue from the sale of energy and the load value is a charge for the purchase of energy. If, as Mr. Dauphinais would have the Commission believe, Ameren Missouri only sells energy whenever its generation exceeds its load and only purchases energy when load exceeds its generation, these settlement statements would only have a value in one or the other tabs in a given hour, not both. But they have values for both generation and load in the same hour, specifically because Ameren Missouri clears/purchases all of its load in each hour and clears/sells all of its generation in each hour from the MISO market.

Q. Doesn't the fact that Ameren Missouri takes Network Integration Transmission Service ("NITS") mean that it is simply transmitting its own generation output to its own load?

A. No. The various tariff provisions that I have already pointed out make it clear that load serving entities, including Ameren Missouri, purchase the power for their load from the MISO. Mr. Dauphinais appears to rest his argument on language found in the preamble to part III of Module B (Network Integration Transmission Service) of the EMT. The language in the preamble remains unchanged from versions of the tariff which existed prior to the establishment of the MISO Day 2 energy market. The MISO has simply failed to properly update this language to reflect the reality of its own market and to conform to the specific provisions in the balance of the tariff which specify that load is purchased from the market and generation is sold into the market (and which were enacted after the establishment of the MISO market).

Q. What portion of the preamble to part III of Module B of the EMT are you referring to?

A. I am specifically referring to the first paragraph which reads:

> The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Owners utilize the Transmission System to serve their Native Load or other Network Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy Energy purchases to its Network Load from non-designated Resources on an as-available basis without additional charge. Transmission Service for sales to non-designated Loads will be provided pursuant to the applicable terms and conditions of Module B of this Tariff and/or any applicable ITC Rate Schedule.

Q. Why do you believe the preamble does not conform to the balance of the EMT?

A. First, the preamble states that NITS allows a Network Customer [e.g., Ameren Missouri] to economically dispatch its Network Resources [e.g., Ameren Missouri's generation]. However, it is the *MISO* in its role as Transmission Provider and Balancing Authority that dispatches the network resources in the MISO market. As such, the preamble fails to reflect the operation of the market.

Secondly, while the preamble states that a Network Customer is allowed to regulate its Network Resources to serve its Network Load, Schedule 3 (Regulating Reserve) of the MISO tariff specifically states that **"(t)he MISO Balancing Authority will procure this service on behalf of the Load Serving Entities** from cleared Resource Offers submitted by Market Participants selected in the Energy and Operating Reserve Markets, as provided for in Sections 39.2 and 40.2 of this Tariff. A Load Serving Entity **must purchase this service** from the MISO Balancing Authority to satisfy its Regulating Reserve Obligation, where such Obligation is defined below." (emphasis added). Again, the more specific provisions of the EMT adopted when the MISO markets began operation reflect what actually happens in the market, while the preamble does not.

Finally, as I've noted above, the preamble language fails to specifically acknowledge the mechanics of the MISO market in regards to load and generation clearing and settlements.

Q. Do you have any other observations on the preamble language?

A. Yes. It bears noting that the preamble, outdated as it is, does specifically provide for the use of NITS to transport Energy purchases.

Q. Please address Mr. Dauphinais' contention that transmission revenues should be removed from the FAC.

A. As Ameren Missouri witness Lynn Barnes indicates in her rebuttal testimony, in our last rate case we recommended that transmission revenues be included in the FAC. This was consistent with the treatment the Staff had recommended for Kansas City Power & Light – Greater Missouri Operations Company ("KCPL-GMO") when a transmission tracker was being discussed in an earlier KCPL-GMO rate case (the Staff supported the tracker in that case, but only as long as transmission revenues were included). We agreed that transmission revenues should be included in the mechanism where transmission costs are included, in our case, in the FAC, although in earlier years the transmission revenues had not changed much so the impact to customers of including or excluding them had been small relative to our total revenue requirement. We continue to think that it makes sense for the revenues to be included in the FAC, as are the costs.

B. <u>Volatility and Uncertainty of FAC Components</u>.

Q. OPC witness Lena Mantle recommends that the FAC be discontinued, contending, in part, that Ameren Missouri has failed to demonstrate that the various cost components are volatile. Are the various cost components of the FAC indeed volatile and uncertain?

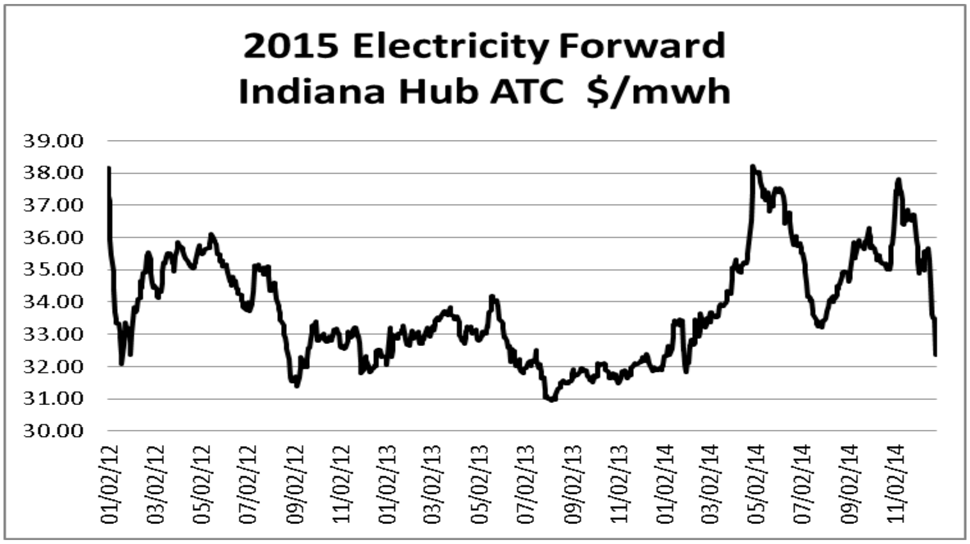
A. Yes. Cost is a function of both price and volume. As a result, even for those components such as coal where we may have relative price certainty for the near term, volatility and uncertainty regarding the volume remains, as discussed in the rebuttal testimony of Ms. Barnes and Company witness Jeffrey S. Jones. Ms. Mantle would seemingly have the Commission ignore the volumetric piece of the equation as she has focused only on the question of price certainty.

The market price for energy remains volatile and is expected to remain so for quite some time. While natural gas fracking and increased installations of wind and other renewable resources have applied downward pressure on electrical energy prices (particularly in the off-peak periods), actual and projected retirement announcements for coal-fired resources resulting from environmental regulations have an opposite and much less certain impact. I am not aware of any party to this proceeding that is arguing that these wholesale market energy prices are not volatile.

Natural gas prices, while currently lower than in recent years, continue to display volatility. It was reported in December that the State of New York has banned fracking. While I am not suggesting that this means that fracking will be banned nationwide, it does highlight the uncertainty that exists regarding what natural gas prices will be in the future. When we consider the dramatic downward movement that we have experienced as a result of the fracking revolution, it is not too difficult to imagine what the impact would be if more jurisdictions were to ban the technology.

Additionally, the price of coal remains volatile. While Ameren Missouri does indeed have long-term contracts for coal purchases in place, it must be recognized that the dispatch cost of our coal-fired units is based on the spot price of coal, not the accounting cost. As a result, fluctuations in the price of coal affect our unit dispatch – again, affecting the volume of coal that is consumed.

I have prepared three simple graphs that show that prices for these three commodities remain volatile and uncertain. Each of these represents the calendar year forward contract for 2015, over the past three years.


2015 Electricity Forward
Indiana Hub ATC $/mwh
39.00
38.00
37.00
36.00
35.00
34.00
33.00
32.00
31.00
30.00
01/02/12
03/02/12
05/02/12
07/02/12
09/02/12
11/02/12
01/02/13
03/02/13
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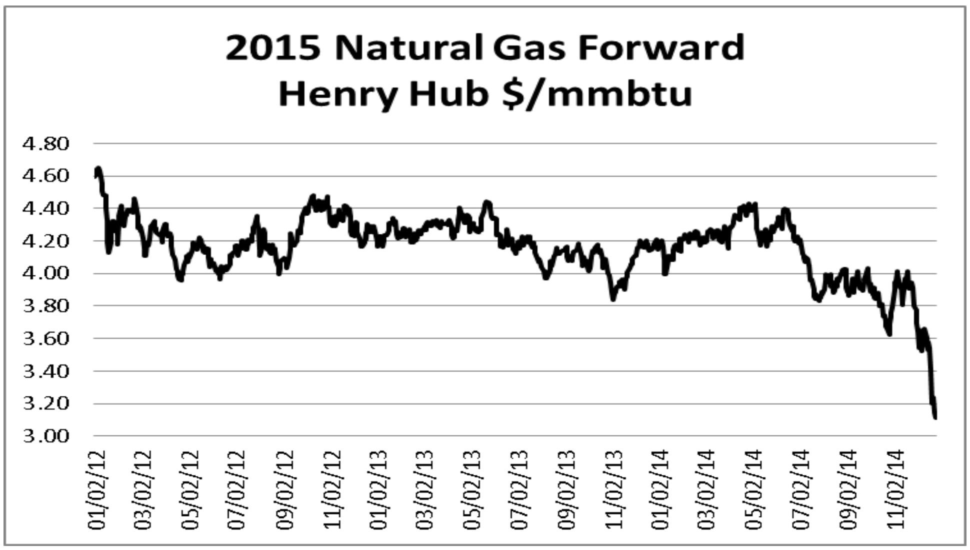
2015 Natural Gas Forward
Henry Hub $/mmbtu
4.80
4.60
4.40
4.20
4.00
3.80
3.60
3.40
3.20
3.00
01/02/12
03/02/12
05/02/12
07/02/12
09/02/12
11/02/12
01/02/13
03/02/13
05/02/13
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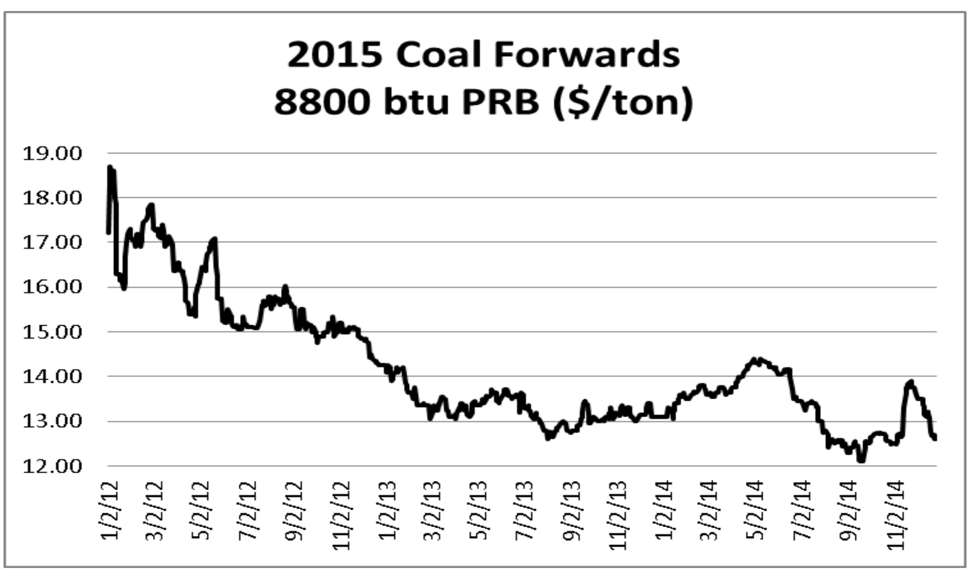
11/02/14


2015 Coal Forwards
8800 btu PRB ($/ton)
19.00
18.00
17.00
16.00
15.00
14.00
13.00
12.00
1/2/12
3/2/12
5/2/12
7/2/12
9/2/12
11/2/12
1/2/13
3/2/13
5/2/13
7/2/13
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Market energy and fuel prices all impact the dispatch of Ameren Missouri's generators.[16] If market energy prices rise faster than increases in the market price of the coal or natural gas fuel burned by the generator, we would expect to see the volume of generation output increase. If market prices rise slower than the rate of increases in the market price of the coal or natural gas fuel input for a generator, we would expect to see the volume of generation output decrease. Of particular interest to this discussion is the impact of wind resources on the prices available to base load, coal-fired generation in the overnight hours. The lowering of off-peak prices frequently results in having such generators dispatched near unit minimums.

Looking at total output and coal cost for our coal-fired generators from 2010 through 2014, we can see very large differences between the years. The change from 2011 to 2012 alone was 14%, and the increase in coal cost from 2012 to 2013 was 11%. While the year-on-year changes in the other years may not have been as dramatic, they should not be dismissed as insignificant. As the table below shows, the lowest year-on-year change in coal cost at the coal-fired units was over $31 million. In just the five years included in the table below, we have seen volume changes between 2% and negative 14% and cost changes between 11% and negative 5%.

	MWH	$	Mwh Change	%	$ Change	%
2014 **	33,059,731	$736,337,348	(269,970)	-1%	$33,939,648	5%
2013	33,329,701	$702,397,700	907,887	3%	$67,187,949	11%
2012	32,421,814	$635,209,751	(5,083,114)	-14%	($34,567,345)	-5%
2011	37,504,928	$669,777,096	606,646	2%	$31,190,538	5%
2010	36,898,282	$638,586,558				

**Includes preliminary values for December 2014.

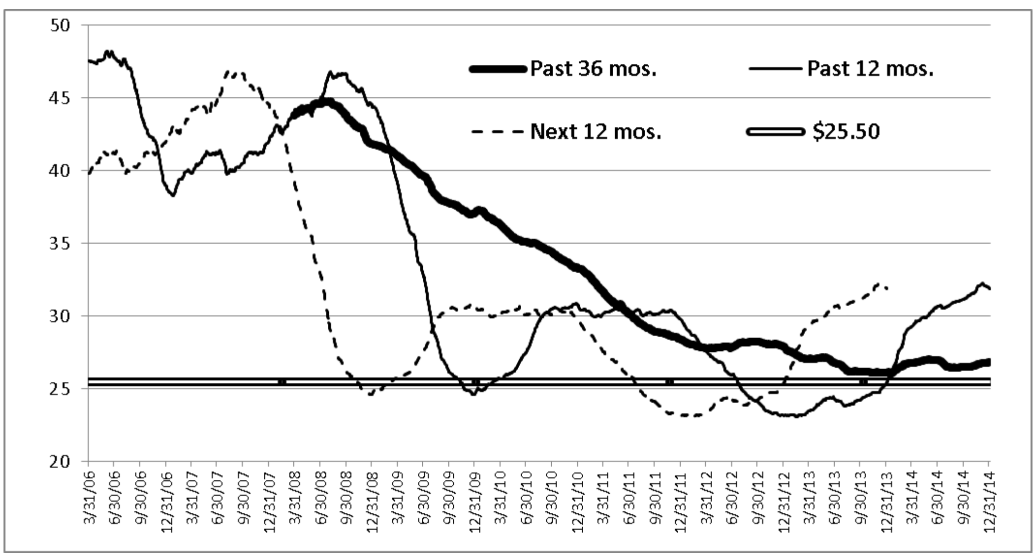
[16] While the actual, contracted-for price for the coal we buy determines our delivered coal costs, it is the market price of coal that determines the dispatch of our units.

Q. Are there other cost components of the FAC which also demonstrate volatility?

A. Yes. In particular, I would note the high degree of volatility in transmission charges associated with Schedule 26A of the MISO tariff discussed above, and the coal commodity and transportation costs discussed in the rebuttal testimony of Ameren Missouri witness Jeffrey S. Jones.

Q. Your market price for energy chart above illustrates the variability in forward prices. Do historical prices also show variability?

A. Yes. The following graph of the average LMP for our coal-fired generators illustrates that both the rolling one year and three-year historical average day ahead LMP have varied greatly over the past seven years, and are currently rising from their lowest values over this same period.



Q. The graph also includes a line labeled "Next 12 mos." What does this line represent?

A. This line illustrates that it is an extremely rare occurrence that the actual price available to our generators in any given 12-month period is equal to (or even close to) the average price for the three preceding years, at a given point in time.

Q. Does this indicate that a three-year historical period to develop normalized prices should not be used to set the off-system sales component of the NBEC?

A. No, it does not. As I stated in my rebuttal testimony in File No. ER-2012-0166, we absolutely have to set a base level of NBEC, and rebasing with more current data than we had when NBEC were last rebased is appropriate, as all parties and the Commission have recognized. However, given the inherent uncertainty in the level of future power prices that supported the establishment of the FAC in the first place, it is simply unreasonable to expect any method to consistently and reliably predict what those future prices will be. I continue to believe the methodology which has been used over the past several cases by all parties who take an interest in off-system sales (essentially the Company, the Staff, and MIEC) is reasonable, and its continued use makes sense. The three-year average, by its very nature, will have less variability than shorter term periods. I am still not aware of any evidence or proposal made by parties to the prior case which would consistently result in a more accurate baseline.

Q. What is the significance of the line labeled $25.50?

A. $25.50 is the normalized "around-the-clock" energy price that has been calculated for the true-up period. This amount was calculated using three years of actual historical generation weighted day ahead LMPs and adjusted to account for the Polar Vortex anomaly.

Q. How does this value compare to the value calculated for the true-up period in the prior rate case?

A. The equivalent value in the last rate case was $28.12.

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 Increase Its Revenues for Electric Service.	)))	Case No. ER-2014-0258

AFFIDAVIT OF JAIME HARO

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

Jaime Haro, being first duly sworn on his oath, states:

1. My name is Jaime Haro. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Senior Director, Asset Management and 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 36 pages and Schedule(s) JH-R1 and JH-R2 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.

Haro

Jaime Haro

Subscribed and sworn to before me this 16th day of January, 2015.

Beckie J. Eaves

Notary Public

My commission expires:

2-21-18

BECKIE J. EAVES
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis City
My Commission Expires: February 21, 2018
Commission Number: 14938572

DEFINITIONS

Day Ahead Energy and Operating Reserve Market: The forward market for purchases and sales of Energy and Operating Reserve conducted by the Transmission Provider the Day prior to the Operating Day.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource.

Fixed Demand Bid: A request to purchase a specified MWh quantity of Energy, at specified locations in the Transmission Provider Region, during specific Hours of the next Operating Day submitted to the Day-Ahead Energy and Operating Reserve Market. Demand Bids may only be submitted by a Market Participant that is itself a Load Serving Entity (LSE) or is purchasing Energy to serve an LSE.

Generation Offer: An Energy Offer, Start-Up Offer, No-Load Offer, Regulating Capacity Offer and Regulating Mileage Offer (if a Regulation Qualified Resource), Spinning Reserve Offer (if a Spin Qualified Resource) an On Line Supplemental Reserve Offer (if not a Spin Qualified Resource) and Off Line Supplemental Reserve Offer (if a Quick Start Resource) submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Generation Resource to supply Energy and/or Operating Reserve to the Energy and Operating Reserve Market.

Offer: An offer, that is duly submitted to the Transmission Provider consistent with this Tariff and the Business Practices Manuals, to (a) sell Energy and Operating Reserve in the Energy and Operating Reserve Markets at a specified price, location, quantity, and time period and shall include (i) Generation Offers, (ii) Demand Response Resource-Type I Offers, (iii) Demand Response Resource-Type II Offers, (iv) External Asynchronous Resource Offers, (v) Stored Energy Resource Offers and (vi) Dispatchable Interchange Schedule Import Schedules and (b) purchase Energy through Fixed Interchange Schedule Import Schedules and Dynamic Interchange Schedule Import Schedules at a specified location, quantity, and time period.

Real-Time Energy Purchases: For a Market Participant, a value in MWh equal to the sum of the following, as applicable:

(i) For Load Zones, the maximum of (a) the difference between (1) Actual Energy Withdrawals (net of Real-Time Financial Schedules) and (2) Day-Ahead Schedules for Energy or (b) zero (0);

(ii) for Resources, the maximum of (a) the difference between (1) Day-Ahead Schedules for Energy or (2) Actual Energy Injections (net of Real-Time Financial Schedules) or (b) zero (0);

(iii) for Virtual Transactions, the Day-Ahead Schedule resulting from a cleared Virtual Supply Offer;

(iv) for Import Schedules, the maximum of (a) the difference between (1) the Day-Ahead Import Schedule and (2) the Real-Time Import Schedule and (b) zero (0);

(v) for Export Schedules, the maximum of (a) the difference between (1) the Real-Time Export Schedule and (2) the Day-Ahead Export Schedule and (b) zero (0); and

(vi) for Real-Time Financial Schedules without any associated Actual Energy Injections or Actual Energy Withdrawals pursuant to Section 40.3.3.a.xvii(i) and 40.3.3.a.xvii(ii), the volume associated with the seller side of the Real-Time Financial Schedule.

Real-Time Energy and Operating Reserve Market: The Market for purchases and sales of Energy and Operating Reserve conducted by the Transmission Provider during the Operating Day.

ASSET OWNER NAME	OPERATING DATE	SETTLEMENT CODE	STATEMENT_ID	CHG_TYP_NM	INT NUM	VAL
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	1	(81,486)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	2	(75,651)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	3	(75,729)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	4	(79,153)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	5	(78,739)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	6	(83,638)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	7	(93,442)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	8	(105,621)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	9	(113,632)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	10	(122,304)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	11	(123,897)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	12	(122,749)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	13	(124,680)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	14	(128,184)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	15	(133,140)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	16	(138,608)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	17	(145,919)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	18	(141,003)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	19	(138,952)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	20	(203,064)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	21	(218,363)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	22	(135,889)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	23	(113,968)
UEGEN	05/04/2014	S7	DA_UEGEN_05112014_05042014-S7	Day Ahead Asset Energy Amount	24	(95,397)

ASSET OWNER NAME	OPERATING DATE	SETTLEMENT CODE	STATEMENT_ID	CHG_TYP_NM	INT NUM	VAL
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	1	78,091.13
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	2	70,995.13
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	3	69,308.57
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	4	64,736.45
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	5	65,256.05
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	6	69,070.43
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	7	77,734.56
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	8	91,026.37
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	9	102,922.01
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	10	116,703.17
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	11	123,512.68
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	12	128,607.63
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	13	136,496.55
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	14	146,538.86
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	15	149,424.62
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	16	149,923.71
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	17	168,812.56
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	18	162,243.05
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	19	154,508.93
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	20	200,730.65
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	21	218,869.84
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	22	144,036.54
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	23	112,264.77
UELSE	05/04/2014	S7	DA_UELSE_05112014_05042014-S7	Day Ahead Asset Energy Amount	24	91,102.05