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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2014-0258

SURREBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
February, 2015

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SURREBUTTAL TESTIMONY

OF

JAIME HARO

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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 and rebuttal testimony in this case?

A. Yes, I am.

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

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony of Office of the Public Counsel ("OPC") Witness Lena Mantle; specifically (1) her allegation that the Net Base Energy Costs ("NBEC") proposed by Ameren Missouri and Staff are too low, (2) her allegation that increasing NBEC will decrease the fuel adjustment clause ("FAC") rate, (3) her recommendation that Financial Swaps not be flowed through the FAC, (4) her allegation that increasing the sharing percentage would provide Ameren Missouri a greater incentive to properly estimate fuel and purchased power costs and off-system sales, and (5) the inclusion and exclusion of certain charges in the FAC.

II. NET BASE ENERGY COSTS

Q. Ms. Mantle states that the Net Base Energy Costs proposed by Ameren Missouri and Staff are too low. Do you agree with her assertion?

A. No. Ms. Mantle's claim is completely lacking in substantive evidence to support it. Furthermore, she acknowledges that she could not identify a problem with either Ameren Missouri's or Staff's modeling, which in large part underlies both the Company's and the Staff's NBEC, nor did she provide an estimate of how much she claims NBEC should be increased.

Q. What approach was used by Ameren Missouri to set NBEC in this proceeding?

A. Ameren Missouri utilized essentially the same approach that the Staff and the Missouri Industrial Energy Consumers ("MIEC") have used for the past several rate cases, and which has been relied upon by the Commission to set NBEC in those cases. I point to those three parties because they are the only parties who model Ameren Missouri's system and who otherwise make efforts to determine the appropriate NBEC. The approach we all use relies upon normalized, historical test year information in developing the inputs for our respective production cost models, and also relies upon test year information to make adjustments for factors that cannot be adequately addressed by the model.[1]

Q. How do the results obtained by Staff and MIEC compare to those obtained by Ameren Missouri?

[1] We all then use updated information through the true-up period for determination of the final NBEC used to set rates and as the base against which changes in the FAC are compared.

A. As Ms. Mantle herself illustrated, all three parties to this proceeding which performed production cost modeling (Ameren Missouri, MIEC and Staff) achieved virtually identical results – the largest variance between to Ameren Missouri's results was 0.68%.

Q. What do these results demonstrate?

A. The fact that three independent parties, one of which (Ameren Missouri) uses a different production cost model than the other two, achieved virtually identical results, demonstrates that our model benchmarks quite well against these other two models. None of the three parties have identified any systemic issues with the model used by any other party in this proceeding.

Q. If Ms. Mantle has not identified a problem with the model or provided any estimate of how much NBEC should be increased, how does she support her claim that NBEC are too low?

A. As best I can determine, Ms. Mantle supports this claim by showing that actual net energy costs ("ANEC") have been higher than NBEC in the past and presenting a chart of the difference between the normalized test year modeled results from our production cost modeling, and the actual costs and revenues from 2014 – stating that this is "a measure to test whether or not the normalized fuel and purchased power numbers are reasonable."

Q. Do you agree with Ms. Mantle that her comparison of the model results from this proceeding with certain components of ANEC for 2014 is a proper test of reasonableness?

A. No, and neither is comparing ANEC to NBEC from prior rates cases, as I will discuss later.

Comparing actual results from 2014 to the results of a model using normalized inputs does not prove that the NBEC were too low or too high for that matter. No one should be surprised that the results are different, as 2014 cannot be reasonably characterized as "normal" – particularly given the effects of the Polar Vortex. In fact, it would be surprising if the results were not materially different given that our process is appropriately based on normalized factors. We normalize market prices, loads and unit outages, among other factors. We don't use a forecasted test year, and in particular we do not attempt (nor would it be appropriate) to forecast actual weather and its impact on load and prices for future periods.[2]

Q. Ms. Mantle states that she does not know why ANEC have been higher than NBEC and offers two possibilities - 1) the NBEC were set too low in the rate cases; or 2) the actual costs changed considerably from when rates were set. Please comment on her observation.

A. First, I find it surprising that Ms. Mantle states that she doesn't know why actual costs have been higher over this entire time period. In my rebuttal testimony in File No. ER-2012-0166, I provided a lengthy discussion on the effect of falling energy market prices on net off-system sales revenue, in rebuttal to Ms. Mantle's own testimony in that proceeding. Because that discussion remains pertinent to Ms. Mantle's testimony now, I have attached my rebuttal testimony from that case to my surrebuttal testimony as Schedule JH-S3. That said, I would agree that by a simple function of mathematics, those are the two possibilities.

[2] Loads are weather-normalized, meaning any variance in the weather from the "normal" levels established for modeling purposes will cause a variance between ANEC and NBEC.

Q. Do you have an opinion on which of those two possibilities is the cause of the adjustments?

A. Yes, one can easily identify the primary cause of the adjustments. The reason lies in the fact that ANEC have consistently been higher than the properly established NBEC, primarily due to the effect of a prolonged period of falling energy market prices on net off-system sales revenue that began in the wake of the recession that started in late 2008/early 2009, and which was likely prolonged by the impact of natural gas fracking, which put additional downward pressure on energy prices.

As I noted in my rebuttal testimony in File No. ER-2012-0166, the total difference between NBEC and ANEC to date was $292.5 million, for the period of March, 2009 through January, 2012. The change in net off-system sales revenue for that same period was $314.5 million. That means that all other costs in the FAC actually decreased by $22 million during that period.[3] As noted earlier, Ms. Mantle was the Staff's FAC witness in that case and filed testimony in response to my testimony. Consequently, as I suggested earlier, there is no reason for Ms. Mantle to have been surprised as she obviously was advised at that time of the drivers of the difference between NBEC and ANEC.

Looking at the subsequent period of February, 2012 through September, 2014, we can see that the difference between NBEC and ANEC was $435.5 million. The change in off-system sales revenue was $467.5 million, meaning once again that the other cost components actually decreased, this time by $30 million (driven in large part by decreases in total generator output).

[3] This does not mean that fuel prices decreased, but simply that total fuel costs decreased because of lower volumes of fuel that was burned.

As shown in the table below, taken in their entirety, ANEC have been higher than NBEC by over $700 million since the start of the FAC. The overwhelming source of this difference has been the change in off-system sales revenue, though other components have varied by tens of millions of dollars.

Ameren Missouri
Fuel Adjustment Clause
Actual Net Fuel Costs versus Net Base Fuel Costs
March 2009 - September 2014
($MILLIONS)

Accumulation Period	1-17	10-17	1-9
	MAR 09 - SEP 14	FEB 12 - SEP 14	MAR 09 - JAN 12
Actual Net Fuel Costs	$ 3,329	$ 1,884	$ 1,444
Net Base Fuel Costs	2,601	1,449	1,152
Difference1	$ 728	$ 435	$ 293
Source of Difference:			
Fuel	$ (96)	$ (112)	$ 16
Net Purch. Power (Energy)	87	63	24
Net OSSR	782	467	314
Other	(26)	18	(63)
Total	$ 747	$ 435	$ 293

(Amounts above do not reflect 95/5 sharing percentage or amounts ordered to be refunded)

In addition, data from this case as compared to the prior rate case demonstrates that energy prices have continued to fall, although recently they have stabilized and have begun to rise, as illustrated later in my testimony. Our periodic FAC adjustment filings and FAC monthly reports, which are provided to OPC, also provide information from which one can determine the reasons for the differences between ANEC and NBEC.

Q. Does it surprise you that ANEC have been higher than NBEC?

A. No. That is exactly what I would expect to find, after the fact, when NBEC are set using normalized market prices over a multi-year historical period during which energy prices were generally falling and where there are pre-established escalations in coal and transportation contract prices occurring beyond the true-up periods used to set the NBEC in each rate case. Had energy prices been trending up during the periods studied we would have seen the opposite effect.

Q. Doesn't the fact that there have been large FAC adjustments prove that the NBEC were improperly set?

A. No. The NBEC were properly set, using a normalized, historical test year approach, consistent with well-established practice before the Commission. The fact that actual costs differed considerably from normalized values from a test year just demonstrates that things change, particularly for cost and revenue components as volatile as those included in the FAC.

If anything, these adjustments are evidence of why a FAC is appropriate and necessary because it is impossible to set a base that will match what actually will happen, almost ensuring that without a FAC the levels assumed when rates were set (which in theory are supposed to be a good proxy for the future) will in fact not be a very good proxy for the future because FAC components are simply too volatile and uncertain to predict with a high degree of accuracy.

Q. Ms. Mantle states that if the NBEC are increased that "(t)he FAC rate would decrease, ideally to close to zero in at least the first accumulation period after new rates went into effect" and "(i)t would be considerably less for subsequent accumulation periods." Do you agree?

A. While I would agree that the FAC rate would decrease relative to what it would be otherwise, I certainly would not agree that the absolute magnitude of any resulting FAC adjustments would be minimized and in fact they may be exacerbated if Ms. Mantle's suggestion were to be followed. More importantly, her suggestion would also result in a higher total cost for customers.

Q. Why do you not agree that the magnitude of future FAC adjustments would be minimized by following Ms. Mantle's recommendation?

A. ANEC will be whatever they are; none of us can know with any certainty what they will be. These costs will be compared to the NBEC established in this proceeding to determine what the FAC adjustment for a given period will be.

The notion that the magnitude of FAC adjustments will be dampened by increasing NBEC is only true if ANEC always end up being higher than the NBEC by at least 50% of the difference between what the NBEC would have been except for being artificially increased, and the artificially increased NBEC.

If, however, the change is less than 50% of that difference, the magnitude of the resulting FAC adjustments will actually be larger than they would have been otherwise, albeit they may be credits instead of charges.

Q. Wouldn't a credit adjustment to the FAC benefit customers?

A. Not if it is generated by artificially increasing NBEC. This is because artificially increasing NBEC increases total costs to customers, even if it does result in future credit adjustments to the FAC. We have to recognize that customers pay both the NBEC and the FAC adjustment. Setting the NBEC higher just means customers pay more of the costs in base rates (including the FAC base factor) and less in the FAC adjustment rate. As such, when the NBEC is artificially increased, customers will always pay more than what they would if the NBEC were properly established.

Q. Can you illustrate how artificially increasing the NBEC would affect the magnitude of FAC adjustments and increase the cost to customers?

A. Yes. The table below provides a simple example which illustrates both points. To the left is a column of different ANEC. The columns in the middle represent an unadjusted NBEC of $670 million, and what the FAC adjustment and total net energy costs (NBEC plus FAC Adjustment) to customers would be at each level of ANEC. The columns immediately to the right do the same, but for NBEC which have been artificially increased by $30 million to $700 million. The furthest right column shows the increase in costs to customers from artificially increasing the NBEC.

	Original NBEC $670 Million		ARTIF. INCR. NBEC $700 Million		
ANEC	**FAC ADJ**	**Total Cost**	**FAC ADJ**	**Total Cost**	**Cust. Incr. Cost**
665	(4.75)	665.25	(33.25)	666.75	1.50
670	-	670.00	(28.50)	671.50	1.50
675	4.75	674.75	(23.75)	676.25	1.50
680	9.50	679.50	(19.00)	681.00	1.50
685	**14.25**	**684.25**	**(14.25)**	**685.75**	**1.50**
690	19.00	689.00	(9.50)	690.50	1.50
695	23.75	693.75	(4.75)	695.25	1.50
700	28.50	698.50	-	700.00	1.50
705	33.25	703.25	4.75	704.75	1.50

As shown in the table, the absolute magnitude of the FAC adjustment is higher under Ms. Mantle's recommendation until actual costs are higher than original NBEC by more than 50% of the difference between original NBEC and the increased NBEC. More importantly, the table illustrates that at every level of actual cost the total cost to customers is $1.5 million higher under Ms. Mantle's recommendation.

Q. Why would customers pay more under Ms. Mantle's recommendation?

A. The amount recovered by customers is higher because of the 5% sharing percentage.

Q. Would increasing the sharing to 10% eliminate this?

A. No. It would actually make it worse. The increased costs to customers would double. The only way to eliminate this disparity is to reduce the sharing percentage from 5% to 0%.

Q. Does this mean that NBEC should be set artificially low?

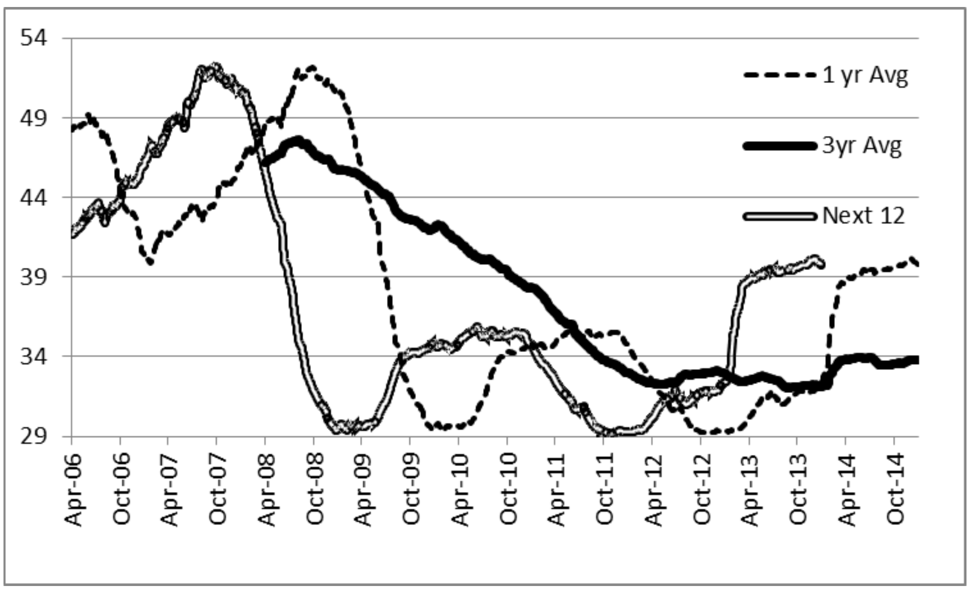
A. No. As with any other factor in a rate case, the goal of setting NBEC should not be to create an unwarranted subsidy for either customers or the Company. The goal should be to obtain a reasonable, normalized result – as right as we can establish, given the inherent limitations that exist using historical, normalized values as a proxy for future, unknown and uncertain actual costs. We should not artificially increase or decrease NBEC.

Q. You previously stated that Ameren Missouri's ANEC could rise but they could also fall, relative to NBEC. What could cause Ameren Missouri's net costs to fall?

A. The most likely reason they would fall is an increase in the offset provided by net off-system sales revenue arising from a prolonged increase in the market price of energy. Costs could also fall if future delivered coal contract prices fall, which is possible given that federal environmental policies and other factors are putting downward pressure on coal prices, and given the pull-back we are seeing in diesel fuel costs which impact the rail fuel surcharges discussed in Ameren Missouri witness Jeff Jones' rebuttal testimony. Whether ANEC increases or decreases over time is largely a function of national and international energy and fuel markets and how they move.

Q. Is it reasonable to believe that market prices for electricity could increase?

A. Certainly. As I testified in my rebuttal testimony, and below, both the rolling one-year and three-year historical average day-ahead locational margin prices ("LMP") for energy in MISO have varied greatly over the past seven years, but they are currently rising from their lowest values over this same period. The graph below is similar to that used in my rebuttal testimony, but this one compares prices for the Indiana Hub.[4] It has values for the rolling 12-month and 36-months averages, as well as for the next 12 months at a given point in time. It clearly illustrates a very wide range in prices over the past 7 years, and shows that prices have risen since the end of 2012.



Q. Would increasing the sharing percentage give Ameren Missouri a greater incentive to "properly estimate fuel and purchased power costs and off-system sales" as Ms. Mantle claims?

A. No. Ms. Mantle's claim is predicated on the notion that the fuel, purchased power and off-system sales components that make up NBEC are not properly established in our rate proceedings. Ms. Mantle is wrong and she has provided no

[4] The Indiana Hub is the most liquid and transparent trading hub in MISO.

substantive evidence to the contrary. She cannot identify any problems with the models or even identify the magnitude of how far off the models are from what she must believe is the right value. Since the largest contributing factor to the differences between NBEC and ANEC have been the changes in market prices, it appears that Ms. Mantle's theory is that a change in the sharing percentage will somehow create a greater incentive for us to better predict what power prices will be when rates are in effect – i.e., in the future. But since power prices are beyond our control, and since there is no way to predict what they are going to be, no amount of incentive is going to lead us to reach a more "accurate" result. As noted earlier, I addressed all of this in my rebuttal testimony in our last rate case, attached to this testimony as Schedule JH-S3.

Q. Shouldn't Ameren Missouri be able to accurately predict what market prices will be in the future?

A. No. First, and most importantly, we aren't predicting prices. We develop reasonable normalized prices to be used in combination with other reasonable normalized factors, including fuel prices and loads to develop a reasonable normalized result in conformance with well-established and accepted practice before the Commission. Nor are Staff and MIEC predicting prices. All three parties reach very similar results and to the extent there are disputes, they generally revolve around an error that one party may have made in initial modeling or a difference of opinion regarding whether a component (usually one that is not captured by the models) should or should not be accounted for in the NBEC.

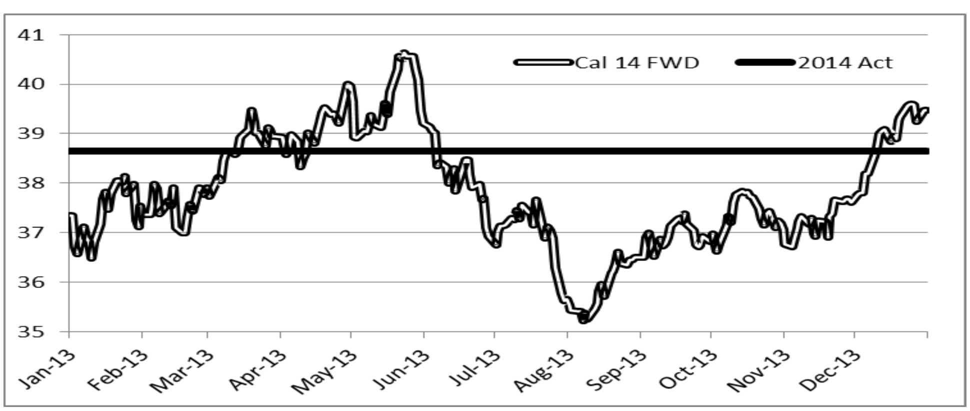
Secondly, as I testified in my rebuttal testimony in File No. ER-2012-0166, power prices are volatile and essentially impossible to predict going forward on a reliable and consistent basis. This hasn't changed in the last two years, and in fact the prices we experienced last year were even more volatile than those I examined in that case.

This is true whether we use historical average power prices (such as is done for ratemaking), or rely on the collective wisdom of the market as represented by the forward market price curves. Simply put, none of these methods is very accurate in consistently and reliably predicting what the price of power is going to be for the next 12 months, let alone for periods beyond the next 12 months.

This is readily illustrated with the use of two graphs. Both graphs use data for the Indiana Hub (previously Cinergy Hub), as there is a visible forward market for the Indiana Hub, for which we gather data. There is not a similar visible forward market for Ameren Missouri's generators.

The first such graph is the one I provided above, which compared the rolling 12 and 36-month average LMPs to the average LMP for the next 12 months. Here we can see that the actual average LMP for any given 12 months rarely coincides with the average LMP for the prior 12 or prior 36 months.

The second graph below compares the visible forward market for the Calendar Year 2014 Around the Clock forward contract for the Indiana Hub as it traded throughout 2013, to the actual average day ahead LMP for the same Hub for 2014.



Both of these graphs illustrate that neither historical averages nor forward prices consistently and reliably predict what the price of power for the next 12 months is going to be. On any given day, one method may be closer to what happened than another, but none of them consistently predict what the actual price is going to be, and many of the gaps between the predictions and the actual prices are huge by anyone's standards. The fact that there are points where the actual 12-month average price crosses one of the other lines is more of an illustration that "even a blind squirrel finds a nut on occasion" than it is that one of these methods is an accurate predictor of future power prices. The graph also shows that for this proceeding, these alternatives are still varying considerably.

Q. Do you have any final observations regarding Ms. Mantle's claim that the NBEC are too low?

A. Yes. On the one hand, Ms. Mantle is highly critical of the approaches used by the Company, Staff and MIEC – which are very much in line with the approach accepted by the Commission in past cases where NBEC was established – saying they are all too low – but then turns around and supports the adjustments to market prices, fuel prices and MISO market settlement charge types due to the Polar Vortex proposed by MIEC Witness Nicholas Phillips. As noted in my rebuttal testimony, Ameren Missouri also supports these adjustments; however, her support for these adjustments, each of which serves to *lower* NBEC, is internally inconsistent with her claim that the NBEC are too low.

Q. Please summarize your testimony regarding Ms. Mantle's claim that the NBEC are too low.

A. Ms. Mantle's claim that the NBEC are too low, by an unspecified amount and without any substantive supporting testimony, is reasonably interpreted as a recommendation to simply increase the NBEC. Doing so is ill advised, not supported by any evidence or analysis and should be rejected.

Ameren Missouri, MIEC and Staff have each independently achieved substantially similar results using a normalized, historical test year approach, consistent with well-established practice before the Commission in developing the inputs for their production cost models. These are the results that should be relied upon by the Commission.

Ms. Mantle's claim that increasing the sharing percentage would somehow give us an incentive to "properly estimate fuel and purchased power costs and off-system sales" is unfounded and simply wrong.

III. FINANCIAL SWAPS

Q. Ms. Mantle also recommends that financial swaps not be flowed through the FAC. Is her recommendation appropriate?

A. No, it is not. Ms. Mantle has completely ignored the purpose for which these transactions are entered into, and glosses over the significant benefit that these transactions have provided customers in recent history.

Q. What reason does Ms. Mantle give for excluding such swaps from the FAC?

A. Ms. Mantle argues that financial swaps should be excluded from the FAC because (she claims) "there is very little incentive for Ameren Missouri to make a profit. Its reward and risk is minimal – it only gets to keep 5% of any profits and it can flow 95% of any losses through to the customers."

Q. Is the purpose of these swap transactions to make a profit?

A. No. While Ameren Missouri would certainly never enter into a transaction on which it would expect to lose money, the fact is that we enter into these transactions for the purpose of fixing the future price on a portion of our net off-system sales, and thus hedging the total margin for our generator output. It is inappropriate to look at the swaps in isolation and not look at the underlying exposure which is being hedged.

Q. What would the consequences be to Ameren Missouri's customers if Ms. Mantle's recommendation was adopted?

A. While she did not use these words, Ms. Mantle is recommending that Ameren Missouri cease hedging a portion of its net off-system sales to mitigate price volatility to customers. Simply stated, adopting Ms. Mantle's recommendation would mean that our customers would be fully exposed to the volatility of spot market prices for those sales.

Q. Why can't we just look at the financial swap transaction instead of looking at it along with the underlying exposure which is being hedged with the swap?

A. Ameren Missouri does not enter into financial swaps for the purpose of speculating on market price movements. We are not gambling on where prices will go. As stated above, these transactions are used to hedge the margin for part of our generation output by fixing the price on a portion of our excess generation and thus mitigating some of the volatility in our net off-system sales. Ms. Mantle has completely ignored the underlying generation exposure that is being hedged.

Q. Please explain how a financial swap is used to hedge generation margins.

A. A financial swap is a transaction in which one party "swaps" their variable price exposure with another party in return for receiving a fixed price.

In our case, we generally have more economic generation available to sell in the market than the megawatt-hours we will need to buy from the market to serve our load. That generation has a fuel cost. If we were to not engage in hedging, this generation would still clear in the MISO market (i.e., the megawatt-hours would still be sold to the MISO market), but would only be paid at the spot LMP. The margin for the generation would be equal to that spot market price of energy minus fuel cost. The price will be whatever the price will be. If prices go up, the margins go up. If prices go down, the margins go down.

As illustrated below and in my rebuttal testimony, these spot market prices are quite volatile. We enter into in hedging transactions to dampen this volatility and to mitigate the risk of harm to customers from falling prices. When we enter into a financial swap we receive a fixed price and pay the counterparty the spot price. Since we are receiving a spot price from the market for our generation, this basically results in the variable prices offsetting, leaving the fuel as a cost and the fixed price for the revenue. This is analogous in the end result to what happened prior to the establishment of the MISO Day-2 market when generation was frequently sold in physical transactions at a fixed price.

Just as with any insurance product however, getting someone else to take on a risk comes at a cost. You can either pay a fixed premium up front or you can forego the benefit of protecting customers against falling power prices. An example of paying a fixed premium would be the purchase of a put option which would obligate another party to pay you a fixed rate in the future if prices were to fall. A financial swap is an example of the second option. By entering into a financial swap, we receive a fixed price and pay the counterparty the variable price. The table below is a very simple illustration of how a financial swap is used to obtain a fixed price for generation output.

	Cost	Rev
GEN	FUEL	~~LMP~~
SWAP	~~LMP~~	FIXED
NET	FUEL	FIXED

Q. Please explain how a financial swap would result in losses for a given transaction.

A. It's quite simple. If the average spot market price for the period covered by the swap is higher than the fixed price received for the swap, the swap itself would lose money. Conversely, if the average spot market price was lower, the swap would make money. In both cases, that is assuming that we ignore the underlying risk that was being hedged.

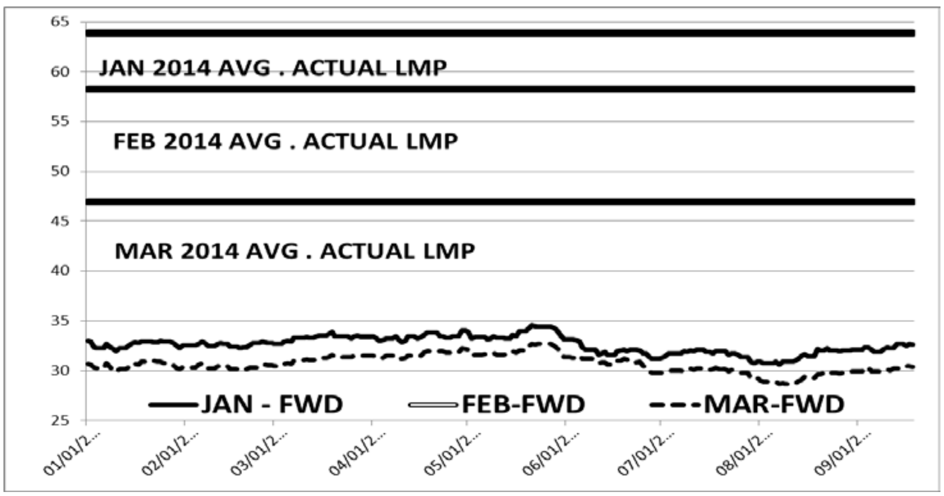
However, I must reiterate that we cannot look at these transactions in isolation, because during that same time period if spot market prices increase, the amount received from the MISO market for the generation we sell to the market increases as well.

Q. Are future spot prices known at the time the swap is entered into?

A. No. There is absolutely no way of knowing what actual spot market prices will be next Tuesday, let alone what they will be a month or year in advance.

Q. You previously indicated that a swap transaction would lose money if spot market prices ended up being higher than the fixed price of the swap. Can you provide an example of where this would occur?

A. Certainly. The best example of this is from the first quarter of 2014. Due to the Polar Vortex, the market experienced extremely high prices that were not reflected in the forward contracts trading all the way up to the very end of 2013. Put another way, the forward markets did not predict the Polar Vortex nor the impact the Polar Vortex would have on energy prices (i.e., the significant increase which occurred). This is not surprising as it is impossible to predict such an unusual and once-in-30-40 years' event. The graph below compares where the individual around-the-clock forward contracts for January, February and March of 2014 at the Indiana Hub traded throughout all of 2013 to the actual average price for the Indiana Hub for those months.



As this chart clearly shows, none of these contracts traded within $10/Mwh of where the actuals came in for the entire year of 2013, and for the January contract, the closest gap was almost $30/MWh.[5]

When one recognizes that the standard contract size is 50 MWh, it is obvious that spot market prices of that magnitude quickly translate into large “losses” as shown in the table below. This table compares the average price that each monthly forward contract

[5] The January and February contract are at virtually the same price, which explains why the February line is not showing on the graph.

was reported at in 2013 to the actual average spot price for the same month, and then multiplies the difference by 50 MW's and then by the number of hours in the month.

	AVG FWD	AVG ACT	DIF	"LOSS"
JAN	$32.59	$63.86	$31.26	$1,162,949
FEB	$32.60	$58.29	$25.69	$863,308
MAR	$30.68	$46.91	$16.23	$603,613
				$2,629,870

Q. Doesn't this just prove that Ameren Missouri should not have entered into forward contracts for 2014 if the prices ended up being that high?

A. No. There simply is no way of knowing what future prices will be, and as the graph above shows, the market certainly did not foresee prices of that magnitude during the prior year.

I cannot emphasize strongly enough that we do not hedge for the purpose of speculation. We hedge to mitigate volatility for our customers. While prices in this situation went up, there are other situations in recent history where prices have fallen and customers have enjoyed the benefit of these hedges. In 2009, when market prices fell precipitously, swap margins exceeded $60 million. If Ameren Missouri had not entered into those hedges, total costs to customers would have increased by $60.6 million. From 2008 through 2014, the net margin on these hedges is over $42 million, yielding a benefit to customers of over $40 million.

Year	Margin ($MILLION)
2008	$ (4.91)
2009	$ 63.82
2010	$ 0.97
2011	$ (5.08)
2012	$ 9.80
2013	$ (2.48)
2014	$ (19.93)
Total	$ 42.19

Q. You stated earlier that Ms. Mantle is basically recommending that Ameren Missouri cease hedging its net off-system sales to mitigate price volatility to customers. Wouldn't that give Ameren Missouri a great opportunity to keep the entire margin instead of sharing it with customers?

A. No. As soon as the tie between the underlying risk (price volatility for our 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.

Q. Please summarize your testimony regarding Ms. Mantle's recommendation that Financial Swaps be excluded from the FAC.

A. Adopting Ms. Mantle's recommendation would mean that Ameren Missouri would cease hedging energy sales for the benefit of our customers. This would leave our customers fully exposed to the volatility of spot market prices for those sales.

I do not believe this is in the best interests of our customers and recommend that Ms. Mantle's proposal be rejected. However, should the Commission determine that Ms. Mantle's proposal should be granted, it must be done with the full acknowledgement that doing so will leave Ameren Missouri's customers fully exposed to the volatility of spot market prices for our net off-system sales.

Additionally, should Ms. Mantle's proposal be granted, it would be inappropriate to adopt Staff and MIEC's proposed adjustment for financial swap margins.

IV. FAC CHARGES AND REVENUES

Q. Ms. Mantle details several expenses and revenue types in the FAC monthly reports that she states were "unexpected" related to Entergy Corporation.

Did Ameren Missouri provide notice of these new charges in accordance with the terms of its FAC tariff as approved by the Commission?

A. Yes. In accordance with the FAC tariff, Ameren Missouri provided a notice of these charge types in its November 2013 FAC report. This notice stated:

> *"Beginning December 1, 2013 MISO instituted 3 new charge types to allow for settlement of Entergy Arkansas pricing zone transmission transactions. The new charge types are "Charge to Recover Costs of Entergy Storm Securitization" (Schedule 41), "Entergy Charge to Recover Interest" (Schedule 42-A) and "Entergy Credit associated with AFUDC" (Schedule 42-B).*
>
> *In accordance with the provisions of Rider FAC, Ameren Missouri is providing notice of the establishment of this new charge type for use in future FAR filings.*
>
> *1) These are transmission charges from MISO so the FERC Account affected by this change is FERC Acct. 565 and activity codes SC41, S42A and S42B.*
>
> *2) These transmission charges possess the characteristic of, and are of the nature of, the transmission charges currently assessed to Ameren Missouri by Entergy to serve Ameren Missouri load using Entergy transmission.*
>
> *3) These new charge types do not replace or supplement any of the existing market settlement charge type(s), but were billed to Ameren Missouri directly by Entergy and included previously in the Fuel Adjustment Clause."*

I am unaware of any party, including the OPC, which challenged the inclusion of these charges following publication of this notice, as is specifically provided for in the FAC tariff. I am similarly unaware of any inquiry from any party, including the OPC, into the nature of these charges following the notice, prior to this proceeding.

Q. What are these charges for?

A. As the Commission is aware, Ameren Missouri has tariffed retail load in what is commonly referred to as the Bootheel of Missouri, which is attached to the Entergy transmission system. (This is separate from Noranda's load). As discussed in my rebuttal testimony in File No. ER-2012-0166, in response to a recommendation made by Ms. Mantle regarding the treatment of transmission charges, Ameren Missouri was required to serve this load using Entergy's transmission system, meaning it incurred transmission charges from Entergy to serve this load. In December, 2013, Entergy joined the MISO and instead of paying transmission charges to Entergy, Ameren Missouri now pays the transmission charges to MISO. MISO chose to create new transmission charge schedules to account for certain of these charges and we then gave notice of them, as the FAC tariff contemplates.

Q. Is it appropriate for these charges to be included in the FAC?

A. Yes. Their inclusion in the FAC was in accordance with the specific provisions in the FAC for including new charge types or MISO schedules. Essentially the same charges were in the FAC before Entergy joined MISO.

Q. Ms. Mantle includes a footnote 18 on page 17 of her rebuttal testimony, that states "The General Ledger Key in the FAC monthly reports show that "AIC" stands for Ameren Illinois Company. If this is indeed a cost for Ameren Illinois, it should not be allowed to flow through to Ameren Missouri customers. OPC is hopeful that Staff will carefully look at this cost in it [sic] the FAC prudence audit that it is currently conducting." Is the charge associated with this footnote a cost that properly should be borne by Ameren Illinois?

A. No. This cost represents the cost of natural gas which Ameren Missouri purchased from Ameren Illinois during the first quarter of 2014, for our natural gas-fired generation needs. It is an Ameren Missouri fuel expense and properly belongs in the FAC.

Q. Has Ms. Mantle recommended the exclusion of other charges and revenues from the FAC?

A. Yes. She has recommended excluding 23 different cost and revenue types which each had a balance of less than $390,000 (either positive or negative) in the test year.

Q. How does Ms. Mantle characterize these costs and revenues?

A. Ms. Mantle portrays them as "non-fuel costs" on page 18, line 12 of her rebuttal.

Q. Do you agree that these charges are non-fuel costs?

A. While I would agree that certain of the 23 charge and revenue types listed are not specifically for fuel, I would disagree that none of them are. More importantly, I would disagree with any suggestion or inference that the costs and revenues which properly belong in the FAC must be for fuel only.

Q. Can you identify which of the 23 charge and revenue types are in fact fuel costs?

A. Yes. Natural Gas Off-System Sales, Oil – Base Load, Gains\Losses on Gas Sales and Natural Gas Base Load AIC are all fuel-related costs.

Q. You also stated that you disagree that the costs and revenues which properly belong in the FAC must be for fuel only. Why is that important?

A. It is important that no one infer from Ms. Mantle's recommendation that only fuel costs are properly included in the FAC. Since its inception, our FAC has included not only fuel costs, but net purchased power, transportation and an offset for net off-system sales. Each of the listed cost and revenues types are properly included in the FAC as they represent a fuel, purchased power or transportation cost, or off-system sales revenue.

Q. At the bottom of page 24 of her rebuttal testimony Ms. Mantle has the following questions and answers:

> Q. WHAT IS THE REVISION TO YOUR RECOMMENDATION IN DIRECT TESTIMONY?
>
> A. OPC agrees with MIEC witness James R. Dauphanais that transmission costs associated with purchased power to serve Ameren Missouri's customers or to make off-system sales should flow through the FAC. In addition, OPC wants to make it clear that revenues from capacity sales, including capacity sales through MISO or any other regional transmission organization, also should be included in the FAC.
>
> Q. IS THIS DIFFERENT FROM WHAT WAS INCLUDED IN THE FAC IN THE PAST?
>
> A. No. It is consistent with the costs and revenues in the first FAC that the Commission approved for Ameren Missouri. Since that first FAC, MISO costs and RTO costs not associated with purchased power have flowed through the FAC. After the last case, where Ameren Missouri first presented testimony on RTO costs in sur-surrebuttal testimony, RTO revenues were added to the FAC.

How would you respond to these statements?

A. It is very unclear to me what point Ms. Mantle is even attempting to make here, especially since both of her answers appear to include factual misstatements.

In her first response, Ms. Mantle seems to offer her support to Mr. Dauphinais' position regarding MISO transmission charges that should flow through the FAC, but she apparently does not understand his position. He has specifically recommended that transmission charges to make off-system sales should be excluded from the FAC, not flowed through as stated in her answer. I already addressed Mr. Dauphinais' position in my rebuttal testimony.

In her second response, Ms. Mantle appears to suggest that MISO charges were not included in the original FAC. My assumption here is strongly reinforced by her claim on page 20 that File No. ER-2012-0166 "was the first rate case where there had been a discussion regarding the inclusion of MISO costs in the FAC and it came late in that case."

Q. Is this claim true?

A. No, it is not true. Ameren Missouri was already an active market participant in the MISO Day-2 energy market, and had been for several years, when the first FAC was approved and put into place in 2009. As a result, a wide variety of MISO charges and revenues (including those applicable to both the purchase and sale of energy) have been included from the inception of the FAC. Similarly, Ameren Missouri has also had market activity in the PJM regional transmission organization prior to and after the FAC was established. Every single FAC tariff has excluded MISO administrative charges. To claim that MISO charges were never discussed until near the very end of File No. ER-2012-0166 is simply untrue.

Additionally, I cannot ascertain her intent behind distinguishing between MISO charges and RTO charges, as the MISO is itself a RTO. MISO revenues have been included from the very beginning of the FAC. We certainly did not wait until after the last case to do so. I can only presume that Ms. Mantle intended to specify that, following the last case, Ameren Missouri began including transmission revenues as an offset to net base energy costs in the FAC. These are the very revenues that Mr. Dauphinais has recommended be excluded from the FAC.

Q. In an effort to support her assertion that accounts with low dollar amounts should be excluded from the FAC, Ms. Mantle also revisits the issue of Ameren Missouri including in the FAC MISO charges for Schedule 26A which were recorded in FERC account 565. These charges, and their inclusion in the FAC, were the subject of litigation in File No. ER-2012-0166. Can you address this issue?

A. Yes. Ms. Mantle leaves out the fact that the current FAC tariff contains provisions which specifically require that Ameren Missouri provide a notice (such as that I quoted previously related to Entergy charges), when new MISO charge types are established. Ms. Barnes addressed this FAC tariff provision in her rebuttal testimony and I referenced it above.

Further, she ignores the fact that the current FAC includes a very high level of detail, including a direct inclusion by reference of a lengthy list of approved MISO charge types in Exhibit H of the *Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues And Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets* approved in File No. ER-2012-0166. This list was developed following extensive discussions between the parties to that case, including Ms. Mantle and other members of the Staff and the OPC.

Finally, she makes no mention of the fact that the Commission in File No. ER-2012-0166 specifically found on the issue of including Schedule 26A charges in the FAC that Ameren Missouri acted appropriately:

> (s)ince the tariff specifically provides that costs of purchased power reflected in account 565 are to be flowed through the fuel adjustment clause, Ameren Missouri acted appropriately in doing so. Indeed, Staff agreed that account 565 costs were to be passed through the fuel adjustment clause within the then current language of the tariff and no party has alleged that Ameren Missouri should be required to make any adjustment for transmission charges that have already been passed through the fuel adjustment clause.

Q. Please summarize your conclusions regarding the issues of the Entergy charges, AIC charges and various RTO/MISO Charges.

A. While Ms. Mantle never comes right out and accuses Ameren Missouri of deceptive and improper behavior, her testimony is littered with innuendo and inferences that something is amiss. What is missing however, is any substantive evidence that this is true, and for good reason. It is not. Ms. Mantle has had access to the monthly FAC reports for years, though as noted by Ameren Missouri witnesses Jesse Francis and Lynn Barnes in their rebuttal testimonies, it appears that she was not using the monthly reports, or at least wasn't using them very much. She has been an active participant in the development of the current and prior FAC tariffs. Her claims that she cannot ascertain what these reports contain and/or that Ameren Missouri can somehow sneak through inappropriate costs ring hollow and should be afforded no weight by the Commission.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Exhibit No.:	
Issue(s):	Fuel Adjustment Clause
Witness:	Jaime Haro
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2012-0166
Date Testimony Prepared:	August 14, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0166

REBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY d/b/a Ameren Missouri

St. Louis, Missouri
August, 2012

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REBUTTAL TESTIMONY

OF

JAIME HARO

CASE NO. ER-2012-0166

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 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 Staff witness Lena Mantle's contention that the existing 95%/5% sharing mechanism in the Company's fuel adjustment clause ("FAC") does not provide sufficient incentive for the Company to prudently make off-system sales because of the difficulty in setting the base off-system sales level for purposes of the FAC. I will also address Ms. Mantle's recommendation that certain language be added to the FAC tariff regarding transmission costs. Finally, I address a proposed treatment of margins from bilateral and swap transactions proposed by Missouri Industrial Energy Consumers ("MIEC") witness James Dauphinais and a similar proposal by Staff witness Erin Maloney.

II. FAC SHARING PERCENTAGE

Q. As noted, Ms. Mantle is recommending that the sharing percentage under the Company's FAC be increased to 85%/15%, from the 95%/5% level which has been in effect for all Missouri electric utilities utilizing an FAC since the FAC was established. She states that such an increase will provide Ameren Missouri with added incentives to more accurately rebase net base fuel costs ("NBFC")[1](the net fuel costs included in base rates in each rate case) and to seek out additional opportunities to make off-system sales. Is Ms. Mantle's proposal justified?

A. No, it is not. First and foremost, Ms. Mantle's proposal assumes that it is possible to accurately predict the power price used in the production cost modeling by the Company, by the Staff, and in recent cases by MIEC to set the off-system sales component of NBFC. In fact, this is a false assumption, as I will demonstrate.

Secondly, this proposal assumes that the Company has not been prudently pursuing available opportunities for off-system sales. That is simply not the case, as I will also demonstrate.

I would note that Ms. Mantle provides no evidence that supports either of her contentions; rather, she posits only unsupported theories of her own making.

Q. Please explain why one cannot assume that Ameren Missouri or any other party can accurately predict the power price used in the production cost model that establishes off-system sales revenue ("OSSR").

A. This assumption is a false one because power prices are volatile and

[1] I will use the term "NBFC" in my testimony, but would note that the Staff has recommended that this term be changed to "NBEC" ("net base energy costs"). The Company has no objection to this change in terminology.

essentially impossible to predict going forward on a reliable and consistent basis. This is true whether we use historical average power prices, or rely on the collective wisdom of the market as represented by the forward market price curves. Simply put, none of these methods is very accurate in consistently and reliably predicting what the price of power is going to be for the next twelve months, let alone for periods beyond the next 12 months.

Ms. Mantle's theory is that a change in the sharing percentage will create a greater incentive to better predict what power prices will be when rates are in effect – i.e., in the future. But since power prices are beyond our control, and since there is no way to predict what they are going to be, no amount of incentive is going to lead us to reach a more "accurate" result.

Q. Have you performed any analysis which supports your claim that future power prices cannot be accurately predicted?

A. Yes. We calculated the 1-year, 2-year and 3-year historical average day-ahead power prices for the periods ending December 31, 2008, 2009, 2010, and 2011, as well as the first seven months of 2012. We also calculated the actual average day-ahead price for calendar years 2009, 2010 and 2011. We then obtained a representation of the forward market price for the applicable annual around-the-clock[2] contract as of the end of each indicated period. Since there is not an available trading hub specific to our system (which could provide a forward price), for purposes of illustration we used a combination of the Cinergy and Indiana Hubs. The Indiana Hub has replaced the Cinergy Hub as the predominant trading hub in the footprint of Midwest Independent Transmission System Operator, Inc. ("MISO").

[2] "Around-the-clock" means the average power price for each 24-hour period (day).

Doing so gave us four different values which arguably could have been used to "predict" (or more appropriately provide a representation of) the price for the next year. We then compared these values to the prices that were actually achieved. The results are shown in the table below.

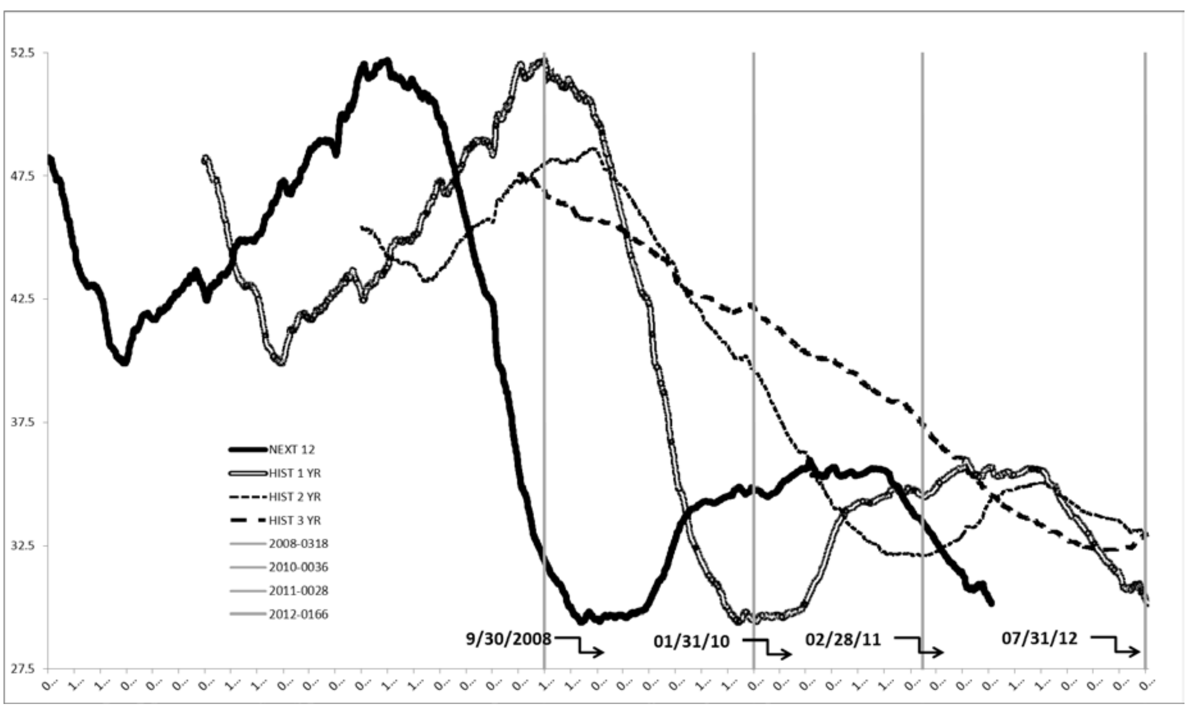
CIN/IND Trading Hub					
As of	12/31/2008	12/31/2009	12/31/2010	12/31/2011	07/31/2012
	CAL 2009	CAL 2010	CAL 2011	CAL 2012	CAL 2013
FWD	$ 41.27	$ 35.12	$ 32.97	$ 31.04	$ 31.14
1 Yr Avg	$ 50.78	$ 29.46	$ 34.81	$ 34.91	$ 30.40
2 Yr Avg	$ 48.42	$ 40.12	$ 32.14	$ 34.86	$ 33.02
3 Yr Avg	$ 45.75	$ 42.10	$ 38.35	$ 33.06	$ 32.91
ACTUAL	**$ 29.46**	**$ 34.81**	**$ 34.91**	**????**	**????**
				$ 29.93	<< YTD July 31
Vs. Actual	2009	2010	2011		
FWD	$ 11.81	$ 0.31	$ (1.95)		
1 Yr Avg	$ 21.32	$ (5.35)	$ (0.10)		
2 Yr Avg 12/31	$ 18.96	$ 5.31	$ (2.78)		
3 Yr Avg 12/31	$ 16.29	$ 7.29	$ 3.44		
%	2009	2010	2011		
FWD	40%	1%	-6%		
1 Yr Avg	72%	-15%	0%		
2 Yr Avg 12/31	64%	15%	-8%		
3 Yr Avg 12/31	55%	21%	10%		

Q. What does this table show us?

A. As I stated above, it shows that none of these methods was very accurate in consistently and reliably predicting what the power prices for the next twelve months will be. Sometimes the forward market price at the end of the previous year would have been more accurate; sometimes a different predictor would have been more accurate. I included the last two columns (Calendar 2012 and 2013) to illustrate that we continue to observe a fairly wide range in the various alternatives.

Q. You chose a single day at the end of each year to include in this table. Couldn't it be that these methodologies would yield a more accurate prediction at some other time of the year?

A. Only by pure chance. The data above is pulled from a larger data set. We also calculated those averages every day over a multi-year period. The graph below shows how the 1-year, 2-year and 3-year averages compared to what the actual average price for the next year ended up being. The heavy black line below is the actual average day-ahead price for the 12 months forward from a given date (it represents what the prices actually ended up being), while the other three lines are the historical averages up to that date (these represent three alternative means of trying to "predict" what the future holds). The light grey vertical lines indicate the end of the true up period for the current and past three proceedings.



Q. What can one conclude from viewing this graph?

A. This graph, like the table above, illustrates that none of these methods are accurate in consistently and reliably predicting what the price of power for the next twelve months is going to be. On any given day, one method may be closer to what happened than another, but none of them consistently predict what the actual price is going to be, and many of the gaps between the predictions and the actual prices are huge, by anyone's standards. The fact that there are points where the actual 12 month average price crosses one of the other lines is more of an illustration that "even a blind squirrel finds a nut on occasion" than it is that one of these methods is an accurate predictor of future power prices. The graph also shows that for this proceeding, these alternatives are still varying considerably.

Q. Are you saying that none of these methods should be used to set the off-system sales component of the NBFC?

A. No, I am not. We absolutely have to set a base level of the NBFC, and rebasing with more current data than we had when the NBFC were last rebased is appropriate, as all parties and the Commission have recognized. But what I am saying is that 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. Absent the unearthing of the price prediction version of the "Rosetta Stone," which would somehow enable us to reliably and consistently achieve such results, I 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 the 1-year or two-year alternatives. I am not aware of any evidence or proposal made by parties to the prior case which would have consistently resulted in a more accurate baseline.

Q. Please elaborate on your last point.

A. I was very surprised by Ms. Mantle's implied suggestion that there may be better methods for predicting future power prices as the Staff itself for three rate cases in a row has consistently submitted testimony either directly recommending, or supporting the recommendations of others, regarding inputs. These recommendations into the model from which off-system sales revenues are determined which, if adopted, would have *increased* the projected level of off-system sales revenues (and thus lowered the NBFC). When one understands that the amount of OSSR included in previous NBFC was too high and this fact was the primary contributor to the significant adjustments to date, it should be obvious that further increasing the level of off-system sales revenues would have increased the variance between the NBFC and the actual net fuel costs even more (and thus increase FAC rate adjustments; i.e., the off-system sales level would have been even *less accurate).* Moreover, in those rate cases we consistently provided testimony and analysis that showed that the Staff's proposals would in fact inject more inaccuracy, and the data shows that we were right about those contentions. To put it bluntly, I am a bit baffled that Ameren Missouri is being criticized by a Staff witness for a result which in reality, despite its magnitude, was still substantially better than the result that would have been achieved if the Staff and the other parties had been successful in increasing the level of OSSR built into NBFC.

Q. Can you demonstrate that the Company has consistently been under-recovering its fuel costs in base rates?

A. Certainly. Since the FAC has gone into effect, a simple comparison of actual net fuel costs (before accounting for amounts ordered to be refunded in Case No. EO-2010-0255) to the NBFC calculated in each of the prior cases, demonstrates that the Company was under-recovered by $292.5 million.

Q. Have you determined the cause of this under-recovery?

A. Yes. When one studies the sources of these under-recoveries at a higher level, the breakdown is as follows:

	(million)
Fuel	$ 16.4
Purch. Power	$ 24.4
OSSR	$ 314.5
MISO costs	$ (34.6)
Other	$ (28.1)
	$ 292.5

Note that with the exception of OSSR, a positive number means that a component turned out to be higher than had been assumed when the NBFC was set. For OSSR, a positive number indicates that revenue turned out to be less than had been assumed.

Q. Do you have an idea of whether the $314 million variance associated with OSSR is related to price differences or changes in volume?

A. Yes. Our analysis clearly demonstrates that price is the overwhelming cause of this difference.

In order to determine this, we first identified what the total volume and average price was that was included in the NBFC calculation for Case Nos. ER-2008-0318 and ER-2010-0036. For the last case (Case No. ER-2011-0028), we did this only for the non-summer periods, as we are currently within the first summer accumulation period following the date the rates set in that case became effective.

We then determined what the total actual OSSR and associated megawatt-hour ("MWh") amounts were for the first twelve full months following the effective date of the rates set in Case Nos. ER-2008-0318, and ER-2010-0036, and the first two full (8 months) non-summer accumulation periods following the effective date for rates set in Case No. ER-2011-0028.

Next we determined the difference in sales volumes between the NBFC calculation and the actuals. This amount was multiplied by the average power price from the NBFC calculation to obtain a rough but reasonable estimate of how much of the variance in OSSR was a result of the sales volume change. Any remaining difference in the OSSR variance was attributed to price changes.

The results of this analysis are presented below.

		1st 12 mos	1st 12 mos	(non-summer)
		ER-2008-0318	ER-2010-0036	ER-2011-0028
NBFC	OSSR	$ 451,748,000	$ 382,137,460	$ 252,144,114
NBFC	MWH	10,082,818	10,567,835	7,787,658
NBFC	Avg. $/MWH	$ 44.80	$ 36.16	$ 32.38
ACTUAL	OSSR	$ 324,417,631	$ 312,623,919	$ 157,381,487
ACTUAL	MWH	11,630,723	10,711,966	5,615,345
ACTUAL	Avg. $/MWH	$ 27.89	$ 29.18	$ 28.03
ACT-NBFC	OSSR	$ (127,330,369)	$ (69,513,541)	$ (94,762,627)
ACT-NBFC	MWH	1,547,905	144,131	(2,172,313)
ACT-NBFC	Avg. $/MWH	$ (16.91)	$ (6.98)	$ (4.35)
Volume	MWH Var * NBFC $/mwh	$ 69,351,940	$ 5,211,839	$ (70,333,846)
Price		$ (196,682,309)	$ (74,725,380)	$ (24,428,781)

Q. What can you tell from the table above?

A. This table clearly shows that the large discrepancies between the power price that was used in the determination of the NBFC and power prices that we were actually able to realize in the marketplace were far and away the largest factor resulting in the FAC adjustments made to date. In the first two columns, it is clear that the sheer magnitude of the price differences overwhelmed any positive contribution to OSSR resulting from increased volumes.

Q. How does the foregoing discussion relate to Ms. Mantle's argument that the sharing percentage in the FAC ought to be changed from 95%/5% to 85%/15%?

A. Ms. Mantle criticizes the Company by essentially claiming that the Company must not have enough incentive (with the 5% sharing) to accurately set the NBFC, since the actual results ended up varying quite a lot from those predicted when the NBFC was set. I've shown that due to the inherent volatility of power prices – which are impossible to predict – there is no method that will allow us to achieve a high level of accuracy that she must assume is possible for the single most significant factor affecting variances in the NBFC.

I've also shown that had we used other parties' recommendations (including the Staff's) in past rate cases the variance between the NBFC and the Company's actual net fuel costs would have been even greater. The bottom line is that the inaccuracy in setting NBFC has nothing to do with incentives. Rather, it is driven by market volatility and by the inability of history or forward market price curves to accurately predict future power prices.

Q. Do you have any other observations relevant to this issue?

A. Yes, I do. Except for MIEC's initial recommendation three rate cases ago that forward prices be used (instead of an historical average price), no party has recommended the use of a different method to calculate power prices for purposes of setting NBFC other than using some form of historical averages. Staff has used a three-year average, and so has MIEC. From the Company's perspective, in the absence of being able to use a forecasted/forward price, we've used a multi-year average because, in general, when a cost or revenue item is prone to variability, such a cost or revenue is often normalized in the ratemaking process and using a multi-year average is a common method of normalization. Staff brought this same issue up in our last case, but in this case too they continued to use a three-year average and so did MIEC.

Q. But isn't the Staff just following the Company's lead with regard to this issue?

A. If they are then it is a departure from what they normally do. In my experience the Staff has its own mind and if it believes a Company methodology isn't accurate enough, it takes issue with it and proposes a different methodology. If our use of a three-year average reflects a "lack of incentive to get it right," as Ms. Mantle contends, then arguably the customers' share should not be reduced from 95% to 85% because then the Staff and MIEC will have less incentive to get it right too. After all, in that scenario customers will bear less of the "inaccuracy" that, as I've shown, is inherent in trying to predict what volatile and uncontrollable power prices will be.

Q. Has Ms. Mantle made this argument before?

A. Yes, and the Commission rejected it just 13 months ago. The Commission stated:

> Staff argues that Ameren Missouri's willingness to accept what it believes to be a flawed basis for the calculation demonstrates that it does not have a sufficient incentive to "get it right." The Commission finds that Ameren Missouri's pragmatic acceptance of the use of historical average sales in the calculation of future off-system sales simply reflects the company's acceptance of the position the Commission clearly stated in previous Ameren Missouri rate case.
>
> This issue was presented to the Commission in File Number ER-2007-0002. In that case, certain parties argued the Commission should establish the amount allowed for off-system sales based on Ameren Missouri's future budgets. In refusing to allow for the use of future budgeted amounts, the Commission stated:
>
>> [s]ince the Commission uses historical expenses and revenues to set rates, it would be fundamentally unfair to reach forward to grab a single budget item to reduce AmerenUE's cost of service, while ignoring other anticipated costs that might increase that cost of service.
>
> Far from evidencing a lack of incentive to "get it right", Ameren Missouri's decision to settle the fuel cost issue simply illustrates the company's willingness to comply with a position clearly stated in a recent Commission decision[3].

We have exactly the same issue here. The NBFC (and as part of it, the power price used to determine OSSR) were settled among the parties in the last rate case as well and the price used in the settlement reflected the three-year average through the true-up period at that time.

Q. Do you have any other evidence that the Staff is not just following your lead?

[3] Case No. ER-2011-0128, Report and Order (effective July 31, 2011) pp. 81-82.

A. Yes. In the last rate case concluded just over a year ago, Ms. Mantle specifically testified that the Staff believed the net base fuel cost numbers that were settled upon in that case and the prior case were reasonable.[4] In fact, as I noted in the last case, and in this case, the Staff is using the same three-year average for power prices that I am using. Ms. Mantle had this to say about use of the three-year average just over one year ago:

> *Q. Staff's been recommending the three-year average of power prices throughout this case; isn't that true?*
> *A. Throughout this case, yes.*
> *Q. And the – and the reason the Staff is doing that is because its [sic] Staff's best judgment that a three-year historical average was the best it could do to predict what the average hourly market price was going to be after rates are set; isn't that right?*
> *A. That is correct.*[5]

Q. Are there other reasons the three-year average continues to be used?

A. Aside from the fact that, as I demonstrated above, it is not clear that another method would yield a more "accurate" result, the Staff at least has made clear that it would object to using forward market prices, as Ms. Mantle's prior testimony demonstrates:

> *Q. And just to be clear, Staff's not going to support using a forward price to set the off-system sales price using the fuel modeling in this case, is it?*
> *A. No, it will not*[6].

So what we have in this case is Ms. Mantle taking us to task for using a methodology the Staff has also used in three cases in a row (and asking us to absorb more prudently incurred net fuel costs). At the same time, she has told us that the Staff would

[4] Case No. ER-2011-0028, Tr. p. 1592, l. 4 – p. 1593, l. 20.
[5] Id., p. 1598, l. 14 – 23.
[6] Id. p. 1598, l. 24 – p. 1599, l. 3.

oppose at least one of the other available methodologies for predicting future power prices.

Q. What would the impact of Ms. Mantle's sharing percentage proposal be?

A. Ms. Mantle's proposal would do one of two things – neither of which will provide us an incentive to accomplish something which quite frankly isn't realistically possible. Those two things are to either unjustly punish or unduly enrich the Company for no other reason than actual power prices ended up being lower or higher than those used to set the NBFC. Neither punishing the Company nor rewarding it under these circumstances is fair or reasonable. Whenever power prices fall – and off-system sales revenue along with them – Ms. Mantle would have the Company put into a position of failing to recover even more of the prudently incurred fuel and purchase power costs it must incur to serve its customers simply based on the fortuity that we were unable to accurately predict future power prices. Alternatively, when power prices rise, her proposal would put customers in the position of foregoing the benefit of lower FAC rates that would be realized as a result of the higher power prices.

In effect, Ms. Mantle's proposal is analogous to creating a lottery ticket for the customers and the Company. If prices go up $1 per MWh, the Company cashes in with an additional $1 million.[7] If prices go down by $1 per MWh, the customers cash in for an additional $1 million. But the $1 million payout in neither case will have been the result of an action or inaction on the part of Ameren Missouri, nor will it have been the result of anything within our control.

Q. What do you mean when you say that Ms. Mantle's proposal would not provide you with an incentive to accomplish something which isn't realistically possible?

A. Ms. Mantle is suggesting that if we had an adequate incentive to "get it right," we would more accurately predict what the price of energy will be a year or two from now. But when energy prices are outside our control, and when there simply is no consistently reliable means of predicting what the prices will be, no amount of "incentive" can achieve the increased accuracy she seeks. In short, no amount of additional incentive will suddenly enable us to do something we have no power to do. Put another way, just because someone is standing over our proverbial shoulders with a big stick (loss of 15% of prudently incurred fuel and purchase power costs) that does not change the fact that not only do we not have a crystal ball into the future, we have no ability to establish the prices at which the market ultimately clears once the NFBC is established.

Q. Aside from the fact that you cannot control power prices and that no one can consistently, reliably predict them, is there other evidence that increasing the sharing percentage in the FAC is not needed to provide the Company greater incentive to seek out additional off-system sales?

A. Yes. We already sell all of our available, "in-the- money" generation.[8] Doing so is simply a function of the MISO market. We don't have to seek out counter-parties to make sure that our generation is economically dispatched. As the parties to this

[7] The $1 million is based on the fact that the Company generally makes about 10 million megawatt-hours of off-system sales each year, thus a $1 change in price equates to $10 million dollars, and Ms. Mantle has proposed increasing the sharing percentage by an additional 10%.

case are well aware, we offer our units into the MISO market, and the MISO clears these units when their cost of generation is lower than the market price. If the cost of dispatching the unit is higher than the market price, the unit does not "clear," it won't be dispatched, and we won't make the sale. It's that simple.

Additionally, we operate within the boundaries of our Risk Management Policy. Despite four prior rate cases over the past approximately five years, and two prudence reviews of the operation of our FAC, our operations have not been criticized. We have not been accused of not making an off-system sale we should have made, or of not realizing an appropriate price. Our Risk Management Policy has not been criticized. We have operated within our Risk Management Policy, as is appropriate, for to do otherwise could expose our customers to unacceptable risks as well as leaving us susceptible to having a transaction deemed imprudent.

Q. What are the consequences of having a transaction deemed imprudent?

A. Simply put, the Company would be responsible for 100% of any incremental costs (i.e., incremental net fuel costs) associated with that decision. That fact alone is more than sufficient incentive to ensure that we reasonably and prudently manage our portfolio.[9]

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[8] "In-the-money" means that the marginal cost of generating additional megawatt-hours will be less than the price we can realize.

[9] And while the Staff may claim that we were imprudent for how we classified the two contracts at issue in Case No. EO-2012-0074, the Staff affirmatively agrees we were prudent for entering into those contracts, and the "classification" of them has nothing to do with prudence.

III. PROPOSED ADJUSTMENTS FOR BILATERAL TRANSACTIONS AND FINANCIAL SWAPS

Q. MIEC Witness Dauphinais and Staff Witness Maloney both recommend that the Commission include a new component in off-system sales revenues – namely the inclusion of incremental margins related to bilateral sales and financial swaps. Do you agree with this recommendation?

A. No. I maintain that their recommendation is unnecessary as it will not, on average, reflect an improvement in the accuracy of setting a base level of OSSR as part of the determination of NBFC.

Q. Please explain.

A. The proposal to include these revenues effectively accomplishes one thing in this case – it increases the amount of OSSR which serves as an offset to fuel and purchased power expenses. Simply put, it lowers the NBFC. This recommendation essentially assumes that Ameren Missouri consistently realizes essentially the same prices for all energy sold, whether at spot or in bilateral transactions or in swaps, as the production cost modeling in the rate case assumed it would realize. If this assumption were correct then I would tend to agree that it may be appropriate to account for the margins associated with bilateral and financial swap transactions (both purchases and sales) in OSSR, as this would theoretically lead to a more accurate setting of the NBFC. However, as I have illustrated above, the fact is that Ameren Missouri does not consistently realize the power prices assumed in the modeling. Moreover, since the FAC was established, the variance from the base is not symmetrical between over- and under-recoveries, as we have been under-recovered in seven out of eight accumulation periods, including each of the last seven, since the FAC was implemented. As discussed previously, the under-recovery was mostly attributable to power prices.

It must also be recognized that had we included such an adjustment in our prior cases, the under-recoveries would have been even larger.

Q. Why do you highlight this latter point?

A. I highlight it because, as I stated above, it illustrates that this adjustment, regardless of its theoretical basis, simply does not reliably improve the accuracy of the starting point. Yes we have, on average, been achieving positive margins relative to spot prices over the past several years. I'm not debating that. That doesn't change the fact that stacking this adder on top of OSSR in the past three cases would have worsened the result. If prices turn around and start to increase and we are able to continue to realize positive margins on average going forward, then it might improve the result. If they don't, it might worsen it yet again. Neither is certain though.

Q. You seem to indicate in this last point that continuing to realize positive margins on these transactions is not certain. Is that correct?

A. Yes. Ameren Missouri enters into bilateral transactions and financial swaps for the purpose of hedging its price exposure. This is important because it has to be recognized that our hedging is not speculation. It is not done to ensure the highest possible price over time, but rather to mitigate the volatility of price movements, for the Company and its customers, over a given period. In simple terms, when someone hedges their sales they are trading the possibility of gains from potential price increases for protection against potential prices drops. Conversely, when they hedge their purchases they trade the possibility of price drops for protection against price increases. The purpose of hedging is not to beat, outsmart or outperform daily or real time markets; it is to lower volatility and ensure some measure of price stability. The transactions at issue were entered into not only to hedge the price received for generation, but also to hedge the price paid for displaced generation – for example when a unit was committed in the day-ahead market but subsequently trips off-line.

It is also important to recognize the simple reality that if prices fall after a fixed price sale transaction is entered into, the trade will show a positive margin, and conversely, if prices increase the transaction will show a negative margin. Given that hedging transactions are entered into in advance of delivery, in some cases months in advance, the margins realized on these transactions are simply a function of where the market moves in the future – a future which I have demonstrated above is unpredictable. Mr. Dauphinais' own workpapers show that for the 24 month period he studied margins were negative in 12 of those months.

Q. Can you summarize your position regarding the inclusion of bilateral and financial swap transactions in the determination of NFBC?

A. Yes. The inclusion of these transactions would not consistently or reliably improve the accuracy of the NBFC, and as such is unnecessary.

IV. TREATMENT OF TRANSMISSION EXPENSE IN THE FAC

Q. Staff has recommended that the following sentence be added to the definition of the cost of purchased power ("PP") in the FAC tariff sheets to be approved in this case: "Only transmission costs incurred for the purchase or sale of electricity shall be included." Is the Staff's recommendation appropriate?

A. It doesn't appear to be.

Q. Please explain.

A. First, the Staff has not provided a sufficient explanation (either in the Staff's Cost of Service Revenue Requirement Report or in the Staff's Rate Design Report) to allow us to understand what problem it is that they are seeking to solve with this new language and why it is only now appropriate to cease accounting for particular charge types through the FAC.

Second, Staff has failed to identify what charges which have previously been accounted for in the FAC, should now be removed from the calculation. They have not provided any clarity on what characteristics would result in disqualifying a particular transmission charge from being considered to have been incurred for the "purchase or sale of electricity."[10]

Third, Staff's proposal may ignore the fact that while Ameren Missouri is a member of the MISO, it also has load which is not electrically connected to MISO's system, and as a result, is required to acquire transmission service (and related charges) on a third party system in order to serve that load, even with its own resources.

Finally, to the extent that Staff may be seeking to exclude charges that Ameren Missouri is required by the MISO tariff to incur in order to secure and utilize network transmission service to serve its load, such exclusion is inappropriate, particularly given that Ameren Missouri's customers served via this network transmission service are enjoying significant market-based benefits which would not reasonably be expected to exist if we were not members of the MISO. These market-based benefits result in a net

[10] Counsel advises that my testimony on this issue should not be taken as a waiver of the Company's right to file additional testimony on this issue if the Staff provides further explanation or support for its proposal that should have been provided when it made its proposal.

reduction to the NBFC and fluctuations are accounted for in the FAC. It is appropriate that transmission costs such as those that Staff may be seeking to exclude, which only exist because of the same MISO relationship which gives rise to these benefits, also be accounted for in the FAC.

Q. Please explain your first and second points.

A. Staff has indicated that the changes to the FAC it has proposed in this case are designed to “clean up” the tariff and make the language in all Missouri FAC tariffs more consistent, and that with the exception of the proposed change to the sharing percentage, there is no intent to change the tariff’s substantive meaning. With respect to this transmission cost language, the Staff hasn’t provided enough clarity to determine what costs, which are currently accounted for in the FAC, they are now seeking to exclude. Staff also has not provided a reasonable justification on why those unspecified charges no longer warrant the treatment they have had these past years. Without this clarity, there cannot be a clear definition of what constitutes transmission costs for the "purchase or sale of electricity." As a consequence, while Staff purports to be doing this to reduce confusion, they will likely be creating it – where none exists today that I am aware of.

Q. Please explain your third point.

A. Ameren Missouri has load which is located in the Missouri Bootheel. This load is electrically located inside of the Entergy system, not the MISO system. We have established the necessary arrangements which allow us to serve this load with our MISO based resources – including securing the necessary network transmission service from Entergy to serve this load, for which we are invoiced. To the extent that Staff’s proposal would be interpreted to exclude the charges from Entergy for service required to serve our load, it is inappropriate – just as it would be inappropriate to exclude charges from the MISO which we must take in order to serve our load.

Q. Please expand on your final point.

A. Ameren Missouri's load (with the exception of the Bootheel load noted above) is electrically located within the MISO footprint, and our entire load (including the Bootheel load) settles within the MISO market. As the Commission may be aware, as a function of the MISO market we purchase and settle with the MISO for 100% of our load. Conversely, we essentially sell 100% of our generation into the MISO. From a practical standpoint, given that we generally have more "in the money" generation to sell than we have load at a given point in time, these amounts effectively net out, leaving us a net seller. Consequently, MISO does indeed issue us "net" settlement statements. This "net" settlement does not erase the fact, however, that we are required to take network service from the MISO to serve our load and as part of taking that service we are billed certain transmission charges by the MISO, which are based upon the amount of load which we serve.

Network service enables us to transmit energy acquired from the MISO market (including that injected by our own generators) to our customers. That service is governed by the MISO tariff and there are a variety of charges from the MISO which may be incurred as the result of utilizing that service. These charges are not ala carte – we cannot pick and choose which ones we have to pay. Even though they exist as distinct schedules, they are required charges if one is using the system to serve load, which we do.

Having our load in the MISO market isn't a one-sided issue of cost though. While our customers do indeed incur these costs as a function of the Company's membership in the MISO, they are also enjoying substantial market-based benefits from being so situated.

While I am aware that there may be differing opinions on how to measure these benefits and that we will be performing a large scale study to again examine this very issue in the next few years, I am also aware that none of the participants in our recent proceeding to extend the Commission's approval to remain in the MISO denied that our customers receive a substantial benefit from our MISO membership, at least for the near future. This benefit arises from the operation of the MISO market and our access to it. As net sellers, we expect to obtain a net margin for our excess generation which we could not reasonably expect to obtain as a stand-alone entity or as a member of another entity without an organized market. Since the revenues from these sales are credited against our fuel costs, our customers are receiving the benefit (or 95% of the benefit) of these enhanced sales. Fluctuations in these revenues from those used to establish the base NBFC are properly accounted for in the FAC.

I am unaware of anyone arguing for, or even hinting at removing from the FAC the benefits which exist because of our MISO membership. However, the Staff's proposed language may reflect a suggestion that we should now cease accounting for some subset of transmission charges within the FAC, even though MISO transmission charges are required as a function of the very same market participation that is delivering the market-based benefits to customers. That is inequitable and unreasonable.

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-2012-0166

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 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 24 pages and Schedule(s) N/A 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.

Jaime Haro

Subscribed and sworn to before me this 13 day of August, 2012.

Carlette Giesler
Notary Public

My commission expires:

CARLETTE GIESLER
MY COMMISSION EXPIRES 11/02/13
NOTARY PUBLIC
NOTARY SEAL
COMMISSION #09401289
GENEVIEVE COUNTY
STATE OF MISSOURI

Schedule JH-S3