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Witness: Jaime Haro
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2011-0028

REBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
March, 2011

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REBUTTAL TESTIMONY

OF

JAIME HARO

CASE NO. ER-2011-0028

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

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 proposals related to the treatment of revenues from bilateral energy and capacity sales and real-time Revenue Sufficiency Guarantee (RSG) make-whole payments presented by Missouri Industrial Energy Consumers' (MIEC) witness James Dauphinais and Staff Witness Erin Maloney. I will also respond to contentions made by Staff Witness Lena Mantle that Ameren Missouri's trading organization, which I lead, does not have the proper incentives to make off-system sales.

Q. Please summarize your conclusions.

A. With respect to the proposals from Mr. Dauphinais and Ms. Maloney, I will show that adding an off-system sales component relating to bilateral sales will likely inject inaccuracy into the rebasing of net fuel costs in this case, thus creating larger fuel adjustment clause (FAC) rate adjustments in the future. With respect to Ms. Maloney's testimony alone, I will also show that adjusting hourly power prices used in the production cost modeling for these bilateral sales will inject inaccuracy into the simulated dispatch of Ameren Missouri's generation. I also discuss an alternative to address the issues raised by Mr. Dauphinais and Ms. Maloney that will improve accuracy, both in the level of off-system sales used to set net base fuel costs in this case and in the simulated dispatch from the production cost modeling performed for this case.

With regard to RSG make-whole payments, I demonstrate that the Company is following the same approach utilized in the last two rate cases, and that by truing-up the actual RSG make-whole payments for the 12-month period ending with the end of the true-up period, an appropriate level of RSG make-whole payments will be included in net base fuel costs.

Regarding Ms. Mantle's contentions relating to a supposed "lack of incentive" to make off-system sales, I will demonstrate that her contentions are inaccurate and unsupported, and that indeed her own workpapers demonstrate this inaccuracy and lack of support.

Finally, I will discuss the fact that the existing exclusion in the FAC for long-term full or partial requirements sales to Missouri municipalities should be eliminated.

II. <u>PROPOSED ADJUSTMENTS FOR BILATERAL TRANSACTIONS</u>

Q. Mr. Dauphinais recommends that the Commission include a new factor or component in the determination of off-system sales revenues – namely the inclusion of a "net bilateral off-system energy sales margin." Do you agree with this recommendation?

A. No, but to fully understand why I disagree requires an understanding of how the main components of the Company's net fuel costs, including off-system sales revenues, are determined in a rate case.

Q. Please explain.

A. It must be recognized that the energy prices used in determining the off-system sales revenue component for this and prior rate cases are based upon an examination of historical price information, usually over a multi-year period. In this case, consistent with the prior proceeding, the parties have been using a three-year period ending February 2011. While it has generally been agreed that the use of a historical average provides an acceptable basis upon which to set a base level of off-system sales revenues, we know that the historical average prices that are being used are extremely unlikely to be realized in actual practice when the rates set in this case are in effect. At certain times the actual prices will turn out to be higher; at other times, lower. If the three-year period being used includes any periods of market disruptions, these variances will be even higher. This is because of the extremely volatile nature of power prices, which are very hard to predict.

Implicit in Mr. Dauphinais' position regarding these bilateral sales is that the historical prices used in the production cost models that determine, in large part, the net base fuel costs are the prices which Ameren Missouri could reasonably expect to obtain in the market going forward. In my opinion, it is very unlikely that the prices Ameren Missouri will actually obtain will be as high as the 3-year historical average. This is because power prices have significantly declined over the past three years. In fact, the current forward around-the-clock price for the 12 months ending July 2012 (the first full year after the new rates will be in effect) is approximately $29.06 per MWh versus the approximately $32.51

per MWh used in the production cost model run conducted by Mr. Finnell. Mr. Dauphinais' proposed adjustment, which uses bilateral sales made during the same three-year historical period referenced above (including bilateral contracts entered into in the early part of that three-year period – 2008 or before, when power prices were very high), if adopted in conjunction with the use of historical prices to establish net base fuel costs will very likely compound any difference between historical prices and those the Company would reasonably expect to actually achieve.

Q. What is the significance of your last comment?

A. The Company has consistently contended that it is important to rebase net fuel costs as accurately as possible each time a rate case is filed, and the Staff has taken the same view. More accurate rebasing will tend to minimize the magnitude of later FAC rate adjustments up or down. The net fuel costs cannot be rebased with absolute accuracy because there are myriad factors that make the components of net fuel costs volatile and unpredictable. However, we can take into account the information in our possession at the time rebasing occurs in an effort to rebase as accurately as possible. Simply put, I am of the opinion that Mr. Dauphinais' suggestion will likely result in even greater FAC adjustments because Mr. Dauphinais adds more off-system sales revenue to an off-system sales revenue figure that will already be very difficult to achieve. This is because, as I noted, the historical prices used in the modeling that determine the level of off-system sales of energy included in net base fuel costs are very likely higher than we will be able to achieve. Consequently, Mr. Dauphinais' suggestion increases even more the likelihood of larger FAC adjustments in the future.

Q. Why don't you use a different method to determine prices used in the modeling?

A. We are attempting to maintain a reasonable level of consistency from case to case. Power prices are highly volatile, which means that using a multi-year average in general does make sense. There may be circumstances when market disruptions or other anomalies warrant changing the period examined, or making some kind of adjustment to the data. Another option would have been to use forward (forecasted) prices, but in general the parties have objected to doing so. My larger point vis-à-vis Mr. Dauphinais' suggestion is that given our use of an historical average of power prices that is probably too high, we should not exacerbate the problem by, in effect, raising the price even more (and thus lowering net base fuel costs even more) because this is likely to inject even more error into net base fuel costs, resulting in even greater FAC adjustments; i.e., even larger FAC rate increases.

Q. Does Mr. Dauphinais' suggestion relate in any way to any proposals to increase the sharing percentage in the FAC?

A. Yes, it does. If off-system sales revenues are overstated (because power prices used in the production cost model are too high), and the FAC sharing percentage is increased as proposed by the Staff, the Company will in effect be required to absorb prudently incurred fuel costs due to no fault of its own, simply because power prices turn out to be lower than those used to rebase net fuel costs in this case. Again, Mr. Dauphinais' proposal makes this situation worse, and in effect will prevent the Company from recovering even more of its prudently incurred net fuel costs.

Given that Ameren Missouri would reasonably expect to make approximately 10 million megawatt hours of off-system sales annually, each $1 reduction in the weighted average price of these sales below that used to rebase net fuel costs equates to roughly a $10 million difference in off-system sales revenues – of which the Company would absorb $500,000 under the 95%/5% sharing. If, however, the sharing percentage were increased to 15%, as proposed by Staff, the Company would be required to absorb an additional $1 million in fuel costs based upon each $1 difference in price. These "disallowances" would occur simply as a result of the market price of power – over which we do not have any control – and not as the result of any action or inaction on the part of the Company. I would also note that even with a 15% sharing mechanism, each $1 difference in price would equate to an additional $8.5 million in FAC adjustment to customers.

Q. Do you have any other observations regarding Mr. Dauphinais' recommendation?

A. Yes. It should be noted that Ameren Missouri enters into bilateral energy transactions for the purpose of hedging its price exposure. Mr. Dauphinais' claim that "if over the long haul the margins from bilateral energy sales were equal to or less than those made by simply selling into the MISO day-ahead and real time energy markets, Ameren Missouri would have likely long ago ceased making bilateral sales of electric energy" ignores this fact.

Q. Why is the issue of hedging important in this discussion?

A. It is important because it has to be recognized that hedging is not speculation. It is not done to ensure the highest possible price over time, but rather to mitigate the possibility of unacceptable price risks 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 price increases for protection against 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 promote price stability. The bilateral 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.

Q. Can you expand on this latter point?

A. Yes. The calculation made by Mr. Dauphinais only looks at bilateral *sales*. When bilateral *purchases* are also included, the net impact of the two (sales and purchases) will be considerably different than just the impact of the sales. In fact, at my request, our settlements group has been tracking bilateral purchases and sales for some time now. In looking at the period March 2010 – January 2011, the *net* impact of these bilateral transactions was just $411,210.

Q. Do you have any further comments on Mr. Dauphinais' proposal?

A. Yes. I would also note that Mr. Dauphinais' suggestion is similar in nature to Office of the Public Counsel witness Ryan Kind's suggestion in Case No. ER-2008-0318 that amounts related to certain "value added" activity by Ameren Missouri's Asset & Trade Optimization Group be added on top of the off-system sales revenues resulting from the production cost modeling done in rate cases. As Ameren Missouri witness Shawn Schukar testified in that case, the modeling "assumes a flawless economic dispatch of the generating units – e. g., the model assumes perfect foresight, that load forecasts and dispatch match perfectly, that the fuel blends at the plant are perfectly matched to offered parameters, and that the bids of energy into the MISO market are perfectly timed." As Mr. Schukar went on to explain: "In fact, no enterprise, even with close monitoring, perfect management and a very high level of market expertise could achieve the performance the model predicts, even if the conditions in the market end up being as assumed in the modeling, because of the day-to-day uncertainties associated with loads, weather, unit operations, and other external factors which can affect operations."

Q. Why do you reiterate Mr. Schukar's discussion of the modeling, which assumes flawless operations?

A. This point is important as it demonstrates that the model yields a base value which one could *not possibly be expected to achieve* even if the actual market conditions exactly matched each and every assumption that had gone into the model. Ameren Missouri's Asset Management & Trading group seeks to minimize the negative impact of any deviations from such perfect operation – as well as normal market price movements. The margins that Mr. Dauphinais has calculated from a very short time period reflect those efforts, and consequently the margins referenced by Mr. Dauphinais are already captured in my recommended level of off-system sales as these were derived from a model which by its very nature assumes perfect execution, perfect execution that in fact no one can achieve.

Q. Please explain the issue you have with Ms. Maloney's proposed treatment of bilateral transactions.

A. I will only address the issue of *how* Ms. Maloney treats bilateral sales and purchases in her calculations. Ameren Missouri witness Timothy D. Finnell will provide further testimony on other deficiencies of her calculations. Before doing so, I would note that it is my understanding that Ms. Maloney, in a response to a data request,[1] has now indicated that she agrees that the proper approach is to utilize the unadjusted day-ahead LMP prices in the model. However, she appears to have conditioned this agreement upon the inclusion of a fixed adder outside of the model to account for bilateral sales. To the extent that the adder that Ms. Maloney is referring to is substantially similar to that proposed by Mr. Dauphinais, I would have the same objection to her proposal as I do to Mr. Dauphinais'. Additionally, to the extent that Ms. Maloney would revert to her initial position if such an adder is deemed inappropriate, I will detail my concerns here.

Ms. Maloney's initial approach – actually adjusting individual hourly prices to incorporate prices for bilateral transactions (both purchases and sales) - is inappropriate as it incorporates prices which were not actually obtainable by our generating units, and may represent average prices over a block period of time and, as a result, would improperly distort the dispatch of generation in the model. This is a different concern than I expressed regarding Mr. Dauphinais' proposal to add a separate component to off-system sales. Mr. Dauphinais is not suggesting that bilateral sales be somehow used in the production cost modeling to dispatch Ameren Missouri's generation. I believe he understands that in actual practice Ameren Missouri isn't dispatching its generation to make these sales, but rather, is making these sales on a "financial" basis. My concern with Ms. Maloney's initial approach

[1] In her response to Data Request UE-Staff-002, Ms. Maloney states as follows: *Staff originally used the combined DA generation sales, DA load purchases, and the RT generation and RT load deviations to reflect market conditions and generate hourly market prices, Staff believed by using all of these prices this method would better reflect the revenues gained from off system sales (OSS). Staff did not break out prices to on and off peak originally because of an oversight. In settlement discussions (discussions occurring on March 2nd and March 3rd between Staff, the Company, and other parties) the parties have come to agree, for the purposes of this case, that using DA generation sales LMP prices would be the most appropriate prices to use to model generation dispatch and send the correct price signal in the REALTIME fuel model. However, if the DA LMP generation sales prices are used in the fuel model, Staff is of the opinion that adjustments should be made outside the fuel model to accurately represent the revenue from off-system sales and bilateral transactions.*

is that she is adjusting prices in the production cost model, and thus influencing the simulated dispatch in the model, using sales that have nothing to do with generation dispatch in the real world.

Q. Can you please expand on your contention that these prices were not achievable by Ameren Missouri's generators?

A. Yes. When we enter into a bilateral sale for example, our generators are paid by the Midwest Independent Transmission System Operator, Inc, (Midwest ISO) at the locational marginal price (LMP) at the actual node where the generator is located. We then buy a like amount at the interface point at the LMP at that location and then sell those megawatts (MW) to the counterparty at the fixed price. When Ms. Maloney incorporates the prices at the interface point in her calculation of prices to be used in the model she is using prices at an interface point – at a Midwest ISO "price node" -- that are different than the price nodes associated with Ameren Missouri's generation. Consequently, these are at prices that Ameren Missouri does not receive. For example, if the LMP at Ameren Missouri's generator node was \$20, the LMP at the interface node was \$30 and the fixed price of the bilateral sale was \$35, Ms. Maloney's approach would use a price that is the average of those three prices to establish the price for that hour at \$28, when, in fact, the price actually achievable by our generator was only \$20. Similarly, when Ms. Maloney includes the price paid by load at the load node, she is including a price that the generator would never see from the Midwest ISO.

Q. But doesn't this just average things out to achieve the same result as Mr. Dauphinais?

A. No, it does not. Ms. Maloney's approach would significantly distort prices for a given hour, and, as a result, her approach would cause a change in the simulated dispatch of generation in the model, a change that wouldn't accurately simulate the actual dispatch that will occur.

Q. Please explain this latter point.

A. The Midwest ISO dispatches generation through the use of price signals – the LMP I discussed earlier. When the LMP for a given unit is equal to or higher than the price offered by that unit, it is dispatched into the market. When the LMP for a given unit is lower than that offered price, it is not dispatched into the market. The production cost models simulate this; the very point of using the models is to simulate, as well as we can, what the *actual* dispatch in the market will be.

By overstating (or understating) the price for a given hour by incorporating price points that our generators could not achieve, the model's simulated dispatch will be inaccurate. In the case above, for the period which Ms. Maloney's model would establish a $28 price, a unit with an offer price of $25 will be dispatched *in the model*, when in fact, it would *not* have been dispatched *in the real world* as the price actually available to the generator was only $20. Ms. Maloney's model therefore would show that generator contributing $3/MWh of off-system sales margin for each MW dispatched, when in fact it never would have been deployed.

Her approach will improperly increase off-system sales revenues and volumes as well as improperly increase projected fuel costs and volumes, both of which distort the model's results.

Q. Are there other issues with Ms. Maloney's approach affecting unit dispatch?

A. Yes. Ms. Maloney fails to make any adjustments to fixed priced transactions over a period of hours/days/weeks, when making her calculations, further skewing the inputs into the production cost model. Take the very simple example of a sale of 50 MW at \$30/MWh for a 4-hour period. Now assume that the actual LMPs for that same time period came in at \$10, \$20, \$40, and \$50, respectively. By not recognizing that multi-period transactions, by their very nature, represent an average of expected prices over that period, Ms. Maloney skews the price for each hour of that period that does not exactly match the fixed price. In this example, if this was the totality of the activity, she would price (in the model) each hour at \$30. If there were two 25 MW units available in the market, one with a cost of \$25 and one with a cost of \$35, her approach would result in the first unit being dispatched in all four hours and the second never being dispatched. In *reality* however, both units would actually be dispatched only in periods three and four. This is another example of her simulated dispatch failing to accurately reflect the actual dispatch, and it is caused by the inappropriate use of these prices in the model.

Q. Do you have any final comments on this issue?

A. Yes. I would like to point out that Mr. Dauphinais and Ms. Maloney are both attempting to include more revenues in off-system sales arising from the fact that Ameren Missouri periodically enters into bilateral transactions at fixed prices, though they do so using very different methodologies. Although I continue to maintain that such an adjustment is not appropriate, should the Commission disagree only one of the two methods should be adopted. To do otherwise, would result in an inappropriate double counting. Moreover, while I do not agree with Mr. Dauphinais' approach (for the reasons discussed above), his approach would be far preferable to Ms. Maloney's approach. As I noted, this is because

Ms. Maloney's approach results in an inaccurate simulation of our dispatch, thus defeating the entire point of modeling dispatch as accurately as possible to set net base fuel costs in this case.

III. <u>RSG MAKE-WHOLE PAYMENT (RSG MWP) MARGIN</u>

Q. Mr. Dauphanais recommends that the Commission adopt 39% for the value of RSG Make-Whole Payment Margins and takes exception to Ameren Missouri's treatment of this item in this case. Do you agree?

A. No. As specifically noted in the Company's response to Staff Data Request No. 250 (attached as Schedule JH-ER3), the approach used in this proceeding is consistent with that used to set rates in the Company's last rate case. In that proceeding, the initial value of 39% presented in direct testimony was the same value that was used to set rates (as part of the true-up) in the case before (Case No. ER-2008-0318). There was no separate calculation made in Case No. ER-2010-0036 until the true-up period. This was explicitly noted in the very data request (MIEC 1-12) from that proceeding that Mr. Dauphanais references in his testimony - "multiplying by 39%, **<u>which was the percentage of margin within the RSG MWP calculated in the prior docket</u>** for this factor." (emphasis added). Ameren Missouri's response to that data request went on to explain that "[a]s with other components of total off-system sales, AmerenUE expects to true-up this calculation and the resulting values as of January 31, 2010."

We have taken exactly the same approach in this proceeding. We utilized the final value from the prior case as a placeholder for this value until obtaining a final value for use in the true-up phase of this case.

Q. Have you been able to calculate the true-up period value?

A. Yes. We now have the fuel and Midwest ISO settlement data available for the complete true-up period of March 1, 2010 – February 28, 2011, which has permitted us to make the calculation.

Q. What value was calculated for the true-up period?

A. 13%.

Q. What value should the Commission use for the MISO RSG make whole payment margins?

A. The 13% noted above, which has been calculated for the true-up period, is the proper value.

Q. Why didn't Ameren Missouri make a preliminary calculation of this value as part of its direct case?

A. Making the calculation is quite time consuming as it involves gathering hourly generation, Midwest ISO RSG MWP, and as-offered production cost data, as well as actual fuel cost data, for each of Ameren Missouri's 46 combustion turbine units. In the past two cases it has taken over two days to compile the data and complete the calculation. As noted previously, this component is part of the true-up process (which utilizes a different time frame than the initial calculations), thus any initial value merely serves as a placeholder and the true-up will necessarily require a complete recalculation.

This was the basis for Ameren Missouri utilizing the same process in this case as it had used in the prior case, where the final value from the prior case served as the initial value until the true-up period when the full calculation was performed.

Q. Mr. Dauphanais recommends that the Commission adopt 39% as the value to be used to determine the MISO RSG make-whole payment margins unless Ameren Missouri presents a calculation prior to the true-up period. Do you agree?

A. No. There is no basis to arbitrarily assign a greater level of confidence to the final value calculated in Case No. ER-2008-0318 than to the final value calculated in Case No. ER-2010-0036. Moreover, there is no basis for believing either value is more appropriate to use than the actual value coming out of the true-up period calculation which we have now performed.

IV. INCENTIVE TO MAKE OFF-SYSTEM SALES

Q. As you noted earlier, Staff Witness Mantle encourages the Commission to adopt a sharing mechanism in the fuel adjustment clause (FAC) that allows the Company to recover less of the change in net fuel costs (85% versus 95%). In part, she contends this change is designed, "to give Ameren Missouri a greater incentive to make OSS." In an attempt to support her contention, she uses a reduction in megawatt-hours (MWh) of off-system sales between the second accumulation period under the FAC (AP2) and the fifth accumulation period (AP5), noting that the average price per MWh increased between those two time periods. Does Ms. Mantle's observation about off-system sales volumes and prices support her contention that a larger sharing percentage should be adopted to give Ameren Missouri a greater incentive to make off-system sales?

A. No, it does not. Ms. Mantle either overlooks or fails to acknowledge that the average price received for off-system sales is based in part on hedging transactions which were entered into well before the revenue from those transactions is realized in a given accumulation period. More importantly however, her analysis is superficial and incomplete. Upon a more detailed review, it is obvious that the reductions in off-system sales volumes which Ms. Mantle references are easily explained using data available in her own workpapers, which show that the volume reduction has absolutely nothing to do with Ameren Missouri's incentive to make off-system sales. In fact, what her own workpapers show is that off-system sales volumes decreased between these two accumulation periods because of significant increases in retail load (i.e., significant increases in the MWhs used to serve retail load, which makes fewer MWhs available for off-system sales), and also because of less generation being available due to major planned maintenance outages at some of our baseload generating units.

Q. Can you please expand upon your first point relating to the making of hedged sales?

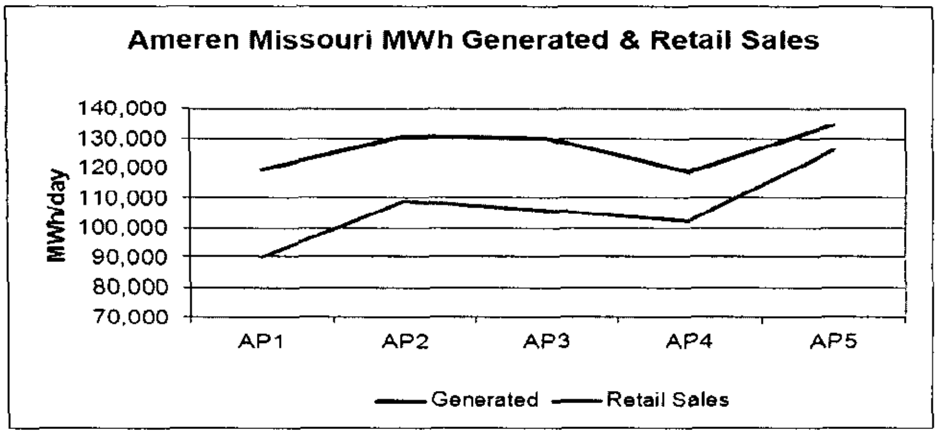
A. Yes. As the Commission and Staff are aware, Ameren Missouri seeks to hedge its (and its customers') price exposure for a significant portion of its off-system sales. It does so by entering into forward transactions several months, if not one or more years in advance of the period of delivery. These prices, which were established in some cases two years prior to delivery, are included in Ms. Mantle's calculation of the average price for off-system sales. Given that there were fewer total MWhs of off-system sales in period AP5 – primarily as a result of increased retail customer loads – these forward sales would constitute a much larger total percentage of off-system sales volumes than they would in AP2 when customer loads were significantly lower (and off-system sales volumes were thus correspondingly higher).

Q. Can you please expand upon your second point relating to increases in retail sales and relating to planned outages?

A. Yes. Between periods AP2 and AP5, Ameren Missouri experienced a significant increase in retail load, which more than accounts for the reduction in off-system sales volumes that Ms. Mantle inaccurately suggests has something to do with a lack of incentives. Additionally, it must be noted that there were planned unit outages in AP5 while there were none in AP2. Similarly, there were major planned outages in AP4 while there were none in AP1. It's obvious that when major baseload units are offline for planned maintenance outages in one period but not in the other that the overall volumes available to make off-system sales will be less, all else being equal. Couple that fact with higher retail loads, and you will see what was observed – lower off-system sales volumes – but this has nothing to do with "incentives."

Q. Please provide more detail on the effect of the increase in retail load between periods AP2 and AP5.

A. I will use Ms. Mantle's workpapers, which were used to develop the graph on page 114 of the Staff Cost of Service Report, to help illustrate my point. These workpapers also include the following graph (which was not presented to the Commission in the Staff's Report), which I have reproduced immediately below.



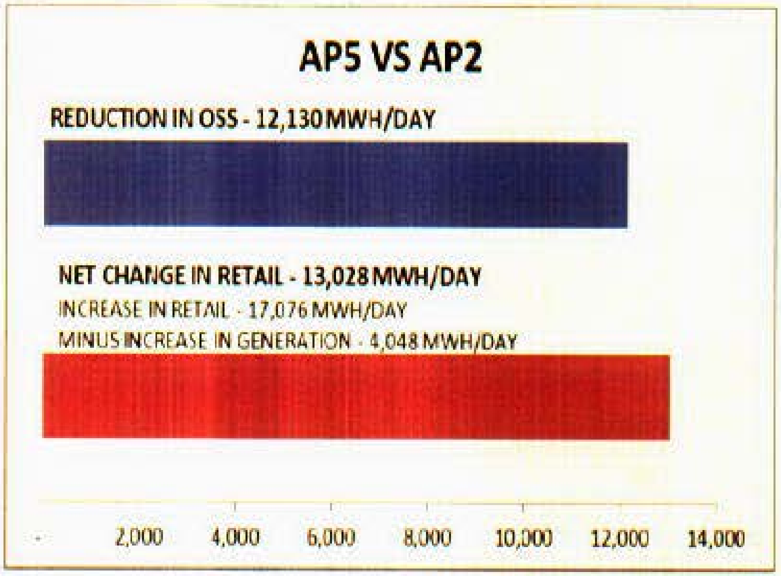
This graph shows a significant increase retail sales (load) between AP2 and AP5, which can be attributed to not only differences in weather, but also to the fact that the load of Noranda Aluminum, Inc., Ameren Missouri's largest customer by far, was down significantly in AP2 continuing into AP4 due to the damage at Noranda's facility caused by the January 2009 ice storm. However, Noranda fully recovered by AP5. A review of meter data shows that the Noranda increase alone accounted for approximately 38% of this increase in retail sales.

These increases in retail sales were partially offset by a modest increase in generation between the two periods. When we look at the numbers behind the graph, we see that retail sales (including Noranda) increased by an average 17,076 MWh per day and generation increased by 4,048 MWh per day. What this means is that the net amount of generation available to make off-system sales *fell* by an average of 13,028 MWh per day from AP2 to AP5.

If we look at the numbers behind Ms. Mantle's graph on page 114 of the Staff Report, however, we will see that off-system sales fell by an average of only 12,130 mwh per day – or approximately 900 MWh's per day on average **less** than the net increase in retail sales.

Simply stated, the **entire** reduction in OSS volumes from AP2 to AP5 is explained – in fact it is more than explained – by the increase in retail sales. It has nothing to do with how diligent Ameren Missouri was in making all of the off-system sales it could at the best prices it could achieve. Rather, it was simply a function of a significant increase in retail load – which obviously must be served first – between AP2 and AP5. Figure 1, below, graphically demonstrates these facts.

Figure 1:



Q. Please provide more detail on the effect of a difference in major planned generator outages.

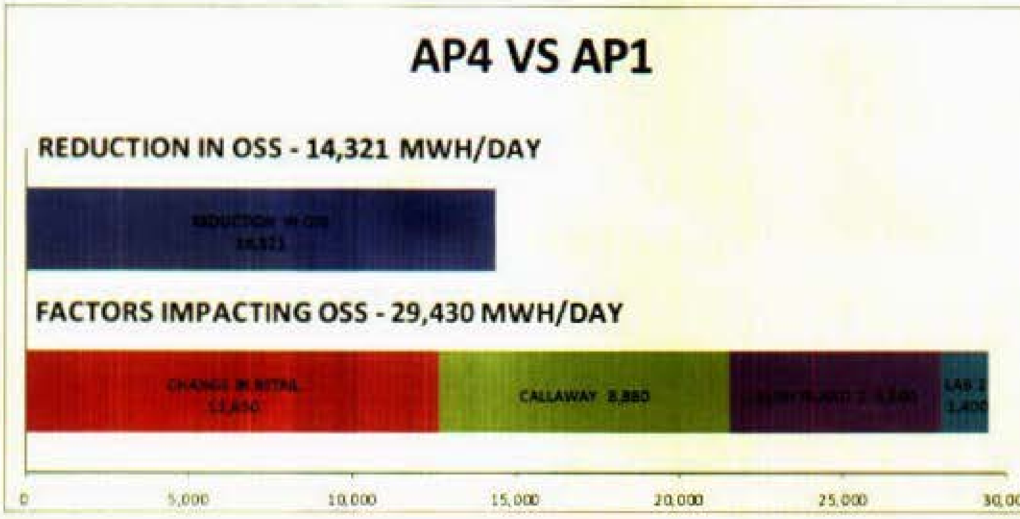
A. Certainly. During periods AP1 and AP2, Ameren Missouri did not have any major planned outages, but there were major planned outages in AP4, including one which extended into AP5, as well as one which began in AP5 and went beyond. Ameren Missouri witness Mark Birk discusses these outages in his rebuttal testimony.

Again, looking at Ms. Mantle's own workpapers, the reduction in off-system sales between AP1 and AP4 was 14,321 MWh per day. Yet, during AP4, the Callaway Plant had a major planned refueling outage for 37 days, Rush Island Unit 2 had a planned outage for 65 days, and Labadie Unit 2 had a planned outage for 14 days. Ms. Mantle, aside from a casual comment that Callaway had an outage, has totally ignored the effect of those outages (which incidentally are done in part to improve power plant efficiency and performance, thus increasing generation for off-system sales in the future) on the MWhs available to make off-system sales.

When we convert these outages into lost MWhs per day, we quickly see that these outages more than account for the reduction in off-system sales volumes between these periods. Callaway's outage accounts for an average of approximately 8,880 MWh per day, Rush Island Unit 2 an average of approximately 6,500 MWh per day and Labadie Unit 2 an average of approximately 1,400 MWh per day - all in AP4. When taken together these three outages represent an average reduction in generation of approximately 16,780 MWh per day in AP4.

This clearly shows that even though these three outages resulted in an average loss of 16,780 MWh per day of available generation in AP4 as compared to AP1, the off-system sales volumes were only reduced by slightly over 14,000 MWh per day between the same periods, and that is before accounting for the fact that retail load also increased between these two periods by an average of 12,650 MWh per day making the entire reduction in generation available for off-system sales over 29,000 MWh per day. Figure 2, below, graphically demonstrates these facts.

Figure 2:



Stated more simply, had we not experienced the generation outages and increased load, and given the same prices, we would have seen an *increase* in off-system sales greater than 15,000 MWh per day. That certainly is not an indication that the Ameren Missouri trade floor lacked the incentive to aggressively make off-system sales.

Q. Didn't the return of the Taum Sauk Plant to service help to offset the reduction in generation MWhs associated with the Callaway outage as Ms. Mantle suggests?

A. No. Ms. Mantle's comment about Taum Sauk returning to service entirely fails to account for the fact that, unlike any of our other generating units, operation of the Taum Sauk facility actually consumes more electrical energy than it generates. This is because the value of Taum Sauk (from an energy perspective) is the ability to pump water up to the upper reservoir at night, during off-peak periods (when power prices are typically lower) and then release it to generate electricity during peak periods (when prices are high), thus capturing the power price differential. But the pumping process consumes approximately 1.4 MWhs of energy for each MWh generated. As such, when one only looks at the volume of off-system sales, as Ms. Mantle has done, the more Taum Sauk runs the greater the reduction in off-system sales volumes, as is illustrated in the table below. Ms. Mantle's suggestion that Taum Sauk would offset lower generation due to outages is simply wrong. Actual data demonstrating these facts appear in the table below:

	TS Gen mwh	TS Pump mwh	Net	mwh/day for AP
5/1/2010 - 5/31/2010	39,727	56,885	(17,158	(143)
6/1/2010 - 9/30/2010	232,063	326,341	(94,278)	(773)

Q. Please summarize your observations regarding the data Ms. Mantle relied upon.

A. The information presented by Ms. Mantle tells only a fraction of the real story, and it demonstrates how raw data can be misinterpreted or misused. The volume of off-system sales Ameren Missouri makes is a function of: (a) retail load, which takes precedence, and (b) available generation, which is influenced greatly by planned outages in one accumulation period versus another. In fact, aside from the RT LMP's used by the Midwest ISO to dispatch generation, those two factors are *the* most important factors. Yet Ms. Mantle ignored them entirely. Higher loads and lower generation due to planned outages, not "imprudence" or lack of effort or lack of incentive, fully explain, and more, the lower off-system sales between these periods, Ms. Mantle's unsupported suggestion to the contrary notwithstanding.

Q. Are there additional reasons that you believe that the current sharing percentages already provide the proper incentives?

A. Yes. Ameren Missouri witness Lynn M. Barnes addresses some of those other reasons in her direct testimony.

Q. Do you have any further comments on Ms. Mantle's suggestion that a reduction in off-system sales supports her recommendation to increase the sharing percentage?

A. Yes. No party to this case has produced any evidence that Ameren Missouri has ever failed to make an off-system sale that we should have made because of any lack of incentive.

V. TREATMENT OF LONG-TERM FULL AND PARTIAL REQUIREMENTS SALES TO MISSOURI MUNICIPALITIES

Q. Ameren Missouri has recommended the elimination of the "jurisdictional allocators" that reflect the long-term full and partial requirements sales to Missouri municipalities. Those sales are specifically excluded from off-system sales in the FAC, which means today the costs associated with them are not allocated to retail customers, and neither are the revenues. However, the Staff is recommending that the current treatment remain in place. Can you please discuss why Ameren Missouri is proposing this change?

A. Yes. In the Second Non-Unanimous Stipulation and Agreement approved by the Commission in the Company's last rate case, the FAC tariff was changed to provide that only long-term requirements sales to Missouri municipalities would be excluded from off-system sales. Given the existing and expected relatively small level of such sales, the Company decided to simplify administration of the FAC and to also eliminate a potential contentious issue in future proceedings by eliminating the agreed-upon exclusion for these contracts.

Q. Please elaborate.

A. Certainly. Our most recent prudence review makes it obvious that any exclusion from off-system sales has the potential to lead to disputes. In that review, the Staff and other intervenors argued for a definition that was applicable to historical cost-based contracts spanning over five years. However, due to fundamental changes in the marketplace, Ameren Missouri has not executed a contract with such characteristics in well over 10 years, nor is there any reasonable expectation that we will do so in the foreseeable future. Ameren Missouri transacts under its market based rate authority and, as a matter of course, does not execute cost-based transactions. While it may have been appropriate in the past to exclude such cost-based transactions via the jurisdictional allocator, there is no compelling reason to do so today.

Q. Are you aware of any other intervenor who has discussed this matter?

A. Yes. Missouri Office of the Public Counsel witness Ryan Kind's surrebuttal testimony in Case No. ER-2010-0036 contains a discussion of the change from cost-based to market-based rate authority sales, changes in the regulatory environment and the potential confusion that exists due to this special treatment.

Q. Are there further reasons to eliminate this special treatment for these contracts?

A. Yes. As they have demonstrated over the past several years, these cities will seek out the best deal available to them – as they should. They freely switch suppliers and there is no guarantee or reasonable expectation that they will necessarily execute a new agreement with the same supplier at the end of a contract. As a consequence, it is Ameren

Missouri's belief that to continue entering into such contracts given the current rate making treatment represents an increasingly unacceptable risk.

Q. Please explain.

A. Once one of these agreements is included in the jurisdictional allocator, the only means that Ameren Missouri has to recover the allocated costs is to ensure that this contract (or a replacement contract of the same relative size) is continually in place. Given the change to the FAC tariff, which now restricts the exclusion to only Missouri municipalities, the universe of available substitutes in the event that a contract terminates and a subsequent agreement cannot be reached with the buyer has become very limited. Not only is it limited to just Missouri municipalities but, more practically, it is limited to those Missouri municipalities that just so happen to be in the market for power and energy at exactly the same time as we would be seeking a buyer.

In the event that a replacement contract cannot be obtained, Ameren Missouri necessarily will under-recover the non-fuel costs that were allocated to that customer (via the jurisdictional allocator) when rates were established. This is because the generation which would have otherwise served this contract load will now be sold as off-system sales. This problem is further compounded when one recognizes the wide range in load requirements of the various Missouri municipalities.

Q. How could Ameren Missouri mitigate this risk?

A. Essentially there are only two means of doing so. The first is to do whatever is necessary to keep such customers under contract, even if that were to mean entering into contracts priced below market, which I do not believe would be appropriate. The second is to avoid this risk all together by eliminating these agreements from our portfolio upon their normal expiration.

It is my opinion that we should be seeking the best available deal when we have excess generation available for sale into the market – regardless of whether the entity is a Missouri municipality or not. However, if the Commission were to decide to retain the jurisdictional allocator, it would be my recommendation that Ameren Missouri no longer include long-term full and partial requirements transactions with Missouri municipalities in our portfolio. Ameren Missouri witness Steven M. Wills provides the jurisdictional allocator that would be needed to account for existing contracts if the Commission did retain the jurisdictional allocator. I would also note that Ameren Missouri witness Gary S. Weiss, in his rebuttal testimony, makes clear that the revenues from those contracts should also be credited in the calculation of the retail revenue requirement in this case.

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 AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area.	)))))	Case No. ER-2011-0028

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 Ameren Missouri consisting of 26 pages, and Schedule JH-ER3, 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.

Jaime Haro

Subscribed and sworn to before me this 25 day of March, 2011.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

Ameren Missouri
Response to MPSC Staff Data Request
MPSC Case No. ER-2011-0028
In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area

Data Request No.: MPSC 0250 – Kofi Boateng

Regarding MISO Day 2 Revenues (GSW-WP-E185), please provide details or summary of your calculations that showed that there are no margins embedded in the RSG make whole payments.

RESPONSE

Prepared By: Mark J. Peters
Title: Managing Supervisor
Date: 12/15/2010

Consistent with its treatment of this matter in the prior case, Ameren Missouri's revenue requirement in its initial filing in this case utilized the results of the true-up period calculation (which was zero) from the prior case (Case No. ER-2010-0036) for this factor. Since the true-up calculation was zero, there are no margins embedded in the make-whole payments.