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Issue(s): Production Cost Model
Witness: Mark J. Peters
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File No.: ER-2014-0258
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2014-0258

REBUTTAL TESTIMONY

OF

MARK J. PETERS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

****Public Version****

St. Louis, Missouri
January 2015

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REBUTTAL TESTIMONY

OF

MARK J. PETERS

FILE NO. ER-2014-0258

Q. Please state your name and business address.

A. Mark J. Peters, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. Manager, Asset & Trading Optimization in the Corporate Planning Department.

Q. Are you the same Mark J. Peters 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 the testimony of Sierra Club witness Dr. Ezra Hausman surrounding the commit status of certain Ameren Missouri generating units in the production cost model; the testimony of Missouri Industrial Energy Consumers ("MIEC") witness Brian Andrews regarding the updating of certain model inputs to reflect the availability of more current data; the testimony of MIEC witness Nicholas Phillips regarding the inclusion of an adjustment to Net Base Energy Charge ("NBEC") for a real time load and generation deviation adjustment and his recommendation of the methodology for calculating the adjustment for real time

Revenue Sufficiency Guarantee-Make Whole Payment ("RSG-MWP") margins; and the methodology utilized by Staff witness Erin Maloney to develop the hourly market price inputs for Staff's production cost model.

Q. Dr. Hausman calculated a change in Off-System Sales Revenue resulting from a change in the commit status for the Meramec Units that differed from the value provided in the response to Data Request SC-008, and stated that he could not identify the source of the discrepancy. Have you been able to identify the source of the discrepancy?

A. Yes. Dr. Hausman simply gathered sales data for the Meramec "not must run case" from the wrong file. In his footnote 34, he stated "I refer specifically to the monthly output files provided by the Company in response to Sierra Club Data Request 008. Monthly output with Meramec set to must-run was provided in the file "SC_1-SC_008_S_Bector-Att-SC008 - MPSC2014PolarVMerMRws - HC.pdf," and output with Meramec set as dispatchable [i.e., not must run] was provided in the file "SC_1-SC_008_S_Bector-Att-SC008 -MPSC2014PolarVSx90ws - HC.pdf." His apparent assumption that the latter file represented the base case with Meramec set to dispatchable (not must run) is not correct. That file represented the change in Sioux coal blend. So, while it did indeed have Meramec set to dispatchable (as did the base case), it also had a different blend for Sioux than the first file. As such, it is not an appropriate file to be used for his calculation because it mixes the impact of the change of the Sioux coal blend with the change in Meramec commit status.

We specifically noted in our response to Data Request SC-008 that the base case files used in the production cost modeling run for our rate case filing could be found in my workpapers as well as Ameren Missouri's responses to Data Request Nos. MIEC 1.05, MIEC 1.11, MIEC 1.12, MIEC 1.21 and MPSC 0077. Those are the files that should have been used in Dr. Hausman's calculation.

Q. Dr. Hausman seems to fault Ameren Missouri for a "failure to consider avoided O&M costs" in its response to Data Request SC-008. Why did Ameren Missouri not consider avoided non-fuel O&M costs in its response to this data request?

A. Ameren Missouri did not consider avoided non-fuel O&M costs in its response because the data request did not ask about O&M costs. Put another way, we answered the question that was asked.

Q. If this data request did not seek information regarding avoided O&M costs, what was its subject matter?

A. The specific subject matter of this data request was fuel costs, net of off-system sales revenue. Even the most liberal reading of the data request could not suggest Sierra Club was asking about avoided non-fuel O&M.

For the convenience of the Missouri Public Service Commission ("Commission"), I have quoted the data request below. As shown, it asked only about the impact of off-system sales and fuel costs and sought no information at all about non-fuel O&M cost impacts.

> *Reference Direct Testimony of Ameren witness Mark J. Peters. On p. 6 at 19, Mr. Peters states,*
> *Each of these changes results in a reduction in Ameren Missouri's net fuel costs. The addition of the O'Fallon Solar Energy Center increases off-system sales revenue, while the change in the Meramec dispatch status and the Sioux fuel blend result in a reduction in fuel costs in excess of the decrease in off-system sales revenue resulting from reductions in unit output.*

> *a. Please provide the analytical basis for Mr. Peters' assertion that "the change in the Meramec dispatch status and the Sioux fuel blend result in a reduction in fuel costs in excess of the decrease in off-system sales revenue resulting from reductions in unit output."*
>
> *b. Please provide all workpapers, analyses, or other documents supporting this assertion, including applicable PROSYM input and output files.*
>
> *c. Please identify the contributions from each of the factors listed by Mr. Peters; i.e., (i) Change in Meramec dispatch status; (ii) Sioux fuel blend; (iii) decrease in off-system sales revenue.*
>
> *d. Did Ameren Missouri analyze or consider whether removing the "must-run" designation from any of its other coal-fired generating units would either increase or decrease off-system sales revenue?*
>
> *e. If the answer to (d) is yes, please provide all workpapers, analyses, or other documents reflecting this analysis or consideration, including applicable PROSYM input and output files.*
>
> *f. If the answer to (d) is no, please explain why not and provide any documents that Ameren Missouri contends support its decision not to analyze or consider this issue.*

Q. Are the supposed avoided non-fuel O&M costs that Dr. Hausman calculated either a fuel cost or an off-system sales revenue?

A. No.

Q. Does the fact that Ameren Missouri's response to Data Request No. SC-008 did not include a value for avoided non-fuel O&M mean Ameren Missouri failed to consider changes in non-fuel O&M costs associated with a change in the unit commit status for the Meramec units in their proposed revenue requirement?

A. No. Dr. Hausman fails to acknowledge or recognize Ameren Missouri utilizes a historical test year approach for establishing the non-fuel O&M costs in its revenue requirement. Since the Ameren Missouri trade floor utilized their current methodology for offering the Meramec units in the test year, whatever impact on non-fuel O&M costs this actual dispatch caused (as opposed to if Meramec had been a must-run plant in all hours) is already captured in the test year non-fuel O&M figures used to set the revenue requirement. Thus, Ameren Missouri did "consider" any non-fuel O&M impacts.

Q. Why haven't you modeled **[redacted] as other than must run?**

A. As noted in the response to Data Request SC-008, **[redacted]** remain must run units in actual operations due to their operating characteristics, high cost to restart, and expected increase in forced outages due to unit cycling. As such, it would be neither meaningful nor appropriate to model them in a manner that differs from expected operations.

Q. Have any other Ameren Missouri witnesses filed testimony addressing the **[redacted]?**

A. Yes. Ameren Missouri witnesses Jaime Haro and Christopher Iselin each have addressed this issue in their rebuttal testimonies.

Q. MIEC Witness Mr. Andrews recommends the Commission reduce Ameren Missouri's net energy costs by $6.4 million due to his proposed updates to fuel prices and market prices. Is Mr. Andrews' recommended adjustment appropriate?

A. I believe Mr. Andrews' recommendation is premature given that these factors will be updated as part of the true-up process and will necessarily change. The appropriate values to use in establishing net energy costs are those that are the result of the ultimate true-up period calculations.

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Q. MIEC witness Mr. Phillips has recommended an adjustment to NBEC for "Net Load and Generation Forecasting Error." Do you agree with this adjustment?

A. As noted in Mr. Haro's rebuttal testimony, Ameren Missouri is willing to include an adjustment for this item (which is more properly characterized as a real time load and generation deviation adjustment) conditioned upon the following:

1) Either all of the following adjustments should be included in the NBEC or none of them should be included: real time RSG-MWP margins, real time load and generation deviations, bilateral and swap margins;

2) The calculation of these adjustments must be corrected as discussed below and by Mr. Haro. Mr. Haro discusses needed adjustments to the calculation of the bilateral and swaps margin adjustment. I will discuss needed adjustments to the real time RSG-MWP margin and real time load and generation deviation adjustments below; and

3) The final value for all of these adjustments should be determined as part of the true-up process through December 31, 2014, and also should reflect a consistent treatment accounting for the polar vortex anomaly.

Q. What adjustment is needed to Mr. Phillips' calculation of a real time load and generation deviation adjustment?

A. Mr. Phillips' calculation needs to be modified to include recognition of the change in fuel cost that occurs when real time generation levels deviate from day-awards. Additionally, I recommend that deviations related to the Taum Sauk Energy Center be excluded from the calculation.

Q. Why do you make the distinction for only the generation deviation and not the load deviation calculation?

A. There is no associated change in fuel cost if the load deviates in real time from the day-award. In the Midcontinent Independent System Operator, Inc. ("MISO") market, the entire load is cleared and purchased from the MISO market and all of the available generation that is "in the money" is cleared and sold into the MISO market.

The MISO real time market is a balancing market – i.e., it is where deviations from the day-ahead awards are settled. If load increases from the day-ahead award, the additional amount settles in the real time market as an additional cost. When the load decreases, it has the effect of "selling back" into the real time market as a credit. Under either scenario, there is no associated change in fuel costs.

However, when generation clears in the day-ahead market, there will be a fuel cost (or pump back cost in the case of stored energy resources such as pumped hydro) associated with that generation if it actually runs in the real time at its day-ahead award level. If the generation increases in real time above the day-ahead award, more fuel will be burned, and if the generation decreases in real time below the day-ahead, less fuel will be burned. As such, there is an associated change in fuel costs for generation from deviations from the day-ahead award.

Q. How should the change in fuel consumption be accounted for?

A. The proper calculation should be the difference in megawatt-hours ("MWh") between day-ahead and real time, multiplied by the difference between fuel cost and the real time locational marginal prices ("LMP") for each non-combustion turbine generator ("CTG") unit, in each hour.

Alternatively, the same result can be achieved by calculating what the margin for that hour would have been if the real time generation had exactly matched the day-ahead award, then comparing that value to what the actual margin ended up being.

The table below provides an example of each equation for a 600 megawatt ("MW") unit with a 300 MW minimum and a fuel cost of $20 per MWh.

	Hour 1	Hour 2
Fuel Cost	$20	$20
DA LMP	$25	$19
RT LMP	$19	$25
DA MWH Award	600	300
RT MWH Act Gen	300	600
Deviation (RT MWH - DA MWH)	-300	300
RT LMP - Fuel Cost	-$1	$5
SIMPLE CALCULATION		
(RT MWH - DA MWH)x(RT LMP-FC)	**$300**	**$1,500**
ALTERNATE CALCULATION		
MARGIN IF RT MWH = DA MWH		
DA Revenue (DA LMP x DA MWH)	$15,000	$5,700
Fuel Cost (DA MWH x FC)	$12,000	$6,000
DA Revenue - Fuel Cost	$3,000	-$300
ACTUAL MARGIN		
DA Revenue (DA LMP x DA MWH)	15000	5700
RT Rev/(Cost) (RT MWH - DA MWH) x RT LMP	-$5,700	$7,500
RT Fuel Cost	$6,000	$12,000
DA Revenue + RT Rev/Cost - FC	$3,300	$1,200
CHANGE IN MARGIN	**$300**	**$1,500**

Q. Does this method match how the deviation has been calculated previously in other rate cases?

A. The calculation of load deviations has not changed as there are no associated fuel costs which change as a result of a deviation.

However, the calculation of proposed adjustments for generation deviations in prior cases failed to include changes in fuel consumption, which arise from a deviation. It is important to note, however, that with the exception of Case No. ER-2008-0318, this proposed adjustment was excluded from the calculation of NBEC or its equivalent.

Q. Does the fact that prior calculations did not include recognition of the change in fuel costs mean the calculation for a real time load and generation deviation adjustment in this case, or in the future, should not include that recognition?

A. No. Recognizing the change in fuel costs associated with a deviation in generation between the day-ahead and real time markets is appropriate because it reflects what actually happens when such deviations occur. The fact that prior calculations failed to properly include such changes in costs is not a valid reason to not use the correct calculation in this proceeding and in the future. Perpetuating the flawed methodology used in past cases does not serve the purpose of attempting to achieve an improvement in the accuracy of the value for NBEC. In fact, doing so is contrary to that purpose and would only serve to embed an inaccuracy in the calculation.

Q. Why do you recommend exclusion of the Taum Sauk Energy Center from this calculation?

A. It is appropriate to exclude the Taum Sauk Energy Center from the calculation of this adjustment due to the manner in which these units are offered and cleared in the MISO market. As a pumped hydro unit, the incremental cost basis for generating at the Taum Sauk facility is the cost of purchasing energy from the MISO market at the applicable Taum Sauk CpNode to pump water back into the reservoir.

Neither MISO market operations nor settlements consider this pumping energy to constitute load that could be cleared as part of Ameren Missouri's load in the day-ahead market. Rather, MISO considers pumping energy to constitute "negative generation" at the facility. Negative generation cannot be offered or cleared in the day-ahead market. As such, pumping energy is only cleared in the real time market. Attempting to determine what pumping cost would have been had Taum Sauk's output exactly matched its day-ahead award in any given hour is a very imprecise exercise.

Q. Would it be proper to use the as offered cost of the Taum Sauk units in a given hour to make this calculation?

A. No. It is my understanding that the as offered cost for the Taum Sauk units represents ** [redacted] **

These are estimates only, and cannot reasonably be represented as the actual costs that would have been incurred for pumping if the unit had matched its day-ahead award in the real time.

Q. Have you calculated what the real time load and generation deviation adjustment should be in this case?

A. Yes. While recognizing this calculation would need to be updated during the true-up process, I calculated the interim value for such an adjustment to be an increase in NBEC of $1.5 million, utilizing data for the period November 2011 through

October 2014. This is comprised of increased cost due to load deviations of $2.8 million, and decreased cost due to generation deviations of $1.3 million. Similar to Mr. Phillips, I replaced the calculated values for the months of January through March of 2014 with the average values for the same months for the two prior years in order to account for the polar vortex anomaly we saw during those months.

Q. Mr. Phillips has also recommended Ameren Missouri should calculate the value for RT-RSG-Make Whole Payment ("RT-RSG-MWP") margins by applying the calculated RT-RSG-MWP margin percentage to the Total RSG and Deviation Revenues, rather than to only the RT-RSG-MWP value. Do you agree?

A. No. It is inappropriate to make the calculation in the manner suggested by Mr. Phillips.

Mr. Phillips appears to base his supports for applying the RT-RSG-MWP margin percentage to the Total RSG and Deviation Revenues rather than only the RT-RSG-MWP value on the assumption that the calculation of the margin percentage itself in Ameren Missouri's previous rate case was based on Total RSG and Deviation Revenues. (Phillips direct, page 16, lines 13-16). While he is correct that the margin percentage used in the initial filing was calculated in the previous case, the assumption that the percentage was calculated using Total RSG and Deviation Revenues is not correct. The margin percentage was calculated using RT-RSG-MWPs only.

Q. How did you determine that the margin percentage calculation was not based on Total RSG and Deviation Revenues?

A. I am the person who, at Mr. Haro's (or his predecessor's) direction, calculated the RT-RSG-MWP margin percentage in each of the Company's prior four cases, including File No. ER-2012-0166. In calculating the margin percentage in each of these cases, I divided the difference between as-offered and actual fuel costs by total RT-RSG-MWP. I did not utilize Total RSG and Deviation Revenues in my calculation of the RT-RSG-MWP margin percentage.

Q. Has this margin percentage remained fixed across these four cases?

A. No. This margin percentage has fluctuated significantly in each of the past four cases. It was calculated at 39%, 0%, 14% and 51% of the total RT-RSG-MWP amount in Case Nos. ER-2008-0318, ER-2010-0036, ER-2011-0028, and ER-2012-0166, respectively.

Q. Did Ameren Missouri apply the RT-RSG-MWP percentage to the Total RSG and Deviation Revenues in determining NBEC or its equivalent in the four prior cases?

A. It appears this has indeed happened in the last two cases (ER-2012-0166/ER-2011-0028), but not in the prior two cases (ER-2010-0036/ER-2008-0318). Applying the RT-RSG-MWP margin percentage, I calculated to the TOTAL RSG and Deviation Revenues when the NBEC supporting schedules were prepared in File Nos. ER-2010-0036 and ER-2012-0166 was an error. The percentage should have been applied to only the RT-RSG-MWPs. In File No. ER-2008-0318, when this adjustment was first established, the amount included in the NBEC equivalent in that case of $5.2 million matches the value I calculated for the difference between as offered fuel and actual fuel. This value was subsequently divided by the total RT-RSG-MWPs of $13.3 million to obtain the margin percentage of 39%. In File No. ER-2010-0036, the calculated difference was negative, and as a result the percentage was set to zero.

As I stated earlier, perpetuating an error does not serve the purpose of attempting to achieve an improvement in the accuracy of the value for NBEC. In fact, doing so is contrary to that purpose and would only serve to embed an inaccuracy in the calculation.

Q. Please describe your understanding of how Staff Witness Ms. Maloney developed her hourly market price input for Staff's production cost model.

A. My understanding is that Ms. Maloney developed her hourly market price input using the following nine steps:

1) Historical Day-Ahead Hourly LMPs for each of Ameren Missouri's generators were obtained for a 36-month period;

2) A simple average of these LMPs was obtained for each hour;

3) Average On-Peak and Average Off-Peak block prices were then calculated for each month of the 36-month period;

4) The average prices for the months of January, February and March of 2014 were replaced with the average price of the corresponding month from the prior two years to remove the price effect of the Polar Vortex Anomaly;

5) The average on-peak and average off-peak price for each month of the 12-month period ending were calculated using the simple average methodology used in step 2 above;

6) The 36-month average block prices were divided by the corresponding 12-month average block price (e.g. On-Peak January / On-Peak January) to obtain a scaling factor;

7) The appropriate peak/month scaling factor was then applied to each hourly price in the 12-month test year period;

8) Ms. Maloney then sorted hourly loads for the test period high to low, and also sorted the hourly prices resulting from step 7 above high to low, for the entire year, thus matching the highest energy price in any hour of the year to the highest load in any hour of the year;

9) Ms. Maloney then resorted these matched load/price pairs using the original date/time order for the load.

Q. Do you agree with Ms. Maloney's methodology?

A. No. I have three specific objections to Ms. Maloney's methodology.

The first is that Ms. Maloney did not weight the calculation of her average hourly price by the amount of the actual daily award for each generator in each hour in step 2 of her process.

The second is that Ms. Maloney unnecessarily adjusts all prices below $5 upwards to equal $5.

The third is that steps 8 and 9 of Ms. Maloney's methodology are inappropriate and should be eliminated.

Additionally, while not a disagreement with the methodology, I observed Ms. Maloney's data set included the individual unit CpNodes for the Osage and Keokuk Energy Centers as well as the CpNodes for the aggregate station (AMMO.CC.OSAGE and AMMO.CC.KEOKUK). The individual unit nodes should be excluded from the data set, and the aggregate nodes should be retained as MISO clears and settles these hydro units in the market as combined cycle using only those two CpNodes - the entire station clears and settles as a single entity versus individual units. Additionally, it appears that the CpNode for Veolia Energy's TriGen station was inadvertently included.

Q. Please expand on your disagreement with the use of a simple average in step 2.

A. The production cost model utilizes the market energy price for each hour to determine when and to what level a generating unit should be dispatched. The price should reasonably represent the price available to the generating units. By not weighting her calculation by the daily awards, the very small Kirksville unit, which clears in the MISO market only on extremely rare occurrences, has exactly the same influence on the calculated average price for each hour as the much larger Callaway unit. Of the over 60 total individual generating units that Ameren Missouri owns and operates (for purposes of this discussion the Osage and Keokuk units each only count as one to reflect how they clear in the MISO market), more than 2/3 are CTGs that rarely run. By using a simple average, 2/3 of the price represents these units, despite their lack of output, injecting significant error into the results she calculated.

The more appropriate methodology for determining these hourly averages is to weight the calculation by the actual amount of the daily award for each generating unit in that hour. By doing this, a unit that did not receive a daily award in that hour is not included in the calculation. Similarly, a larger unit that receives a day-ahead award will have a greater contribution to the hourly average than a smaller unit which receives a day-ahead award.

It is my understanding that MIEC witnesses Messrs. Phillips and Andrews utilize the same weighted average approach I just described in developing their average hourly market prices.

Q. Please discuss your disagreement with Ms. Maloney's practice of adjusting prices below $5 to equal $5.

A. Ms. Maloney has not provided a justification for adjusting actual market prices. Prices below $5 while rare, do occur and I am unaware of a valid reason to exclude them. They should remain in the data set.

Q. Please expand on your disagreement with steps 8 and 9 of Ms. Maloney's methodology.

A. By performing these two steps, Ms. Maloney's methodology forces a 1-1 correlation between prices and load – that is, the highest price is always matched with the highest load. This process eliminates the actual relationship between prices and load which existed during the test year period and replaces it with an unsupported assumption that the highest price must necessarily occur in the hour with the highest load, the second highest price in the hour with the second highest load, and so on. When the matched pairs are re-sorted into date/time order, using the date/time for the load, prices that are now in January may have originated in July. Prices at 6 a.m. may have actually originated from 9 p.m.

Steps 8 and 9 are unnecessary and, in fact, inject a level of inaccuracy into the process. The relative relationship between actual hourly prices and loads that existed during the test year is maintained if these steps are eliminated. It is important to leave those existing relationships intact as they are more proper in representation of the variety of system conditions that may impact prices than would be accomplished by artificially assigning prices to loads without a consideration of the system conditions which gave rise to those prices.

Q. Do the highest priced hours perfectly match with the highest load hours?

A. No. As the chart below illustrates, the highest priced hour in any given year for the AMMO.UE CpNode (the pricing node used to settle Ameren Missouri's load) and the highest load cleared in the day-ahead market in the same year do not match up. The same is true when looking at the minimum price and loads.

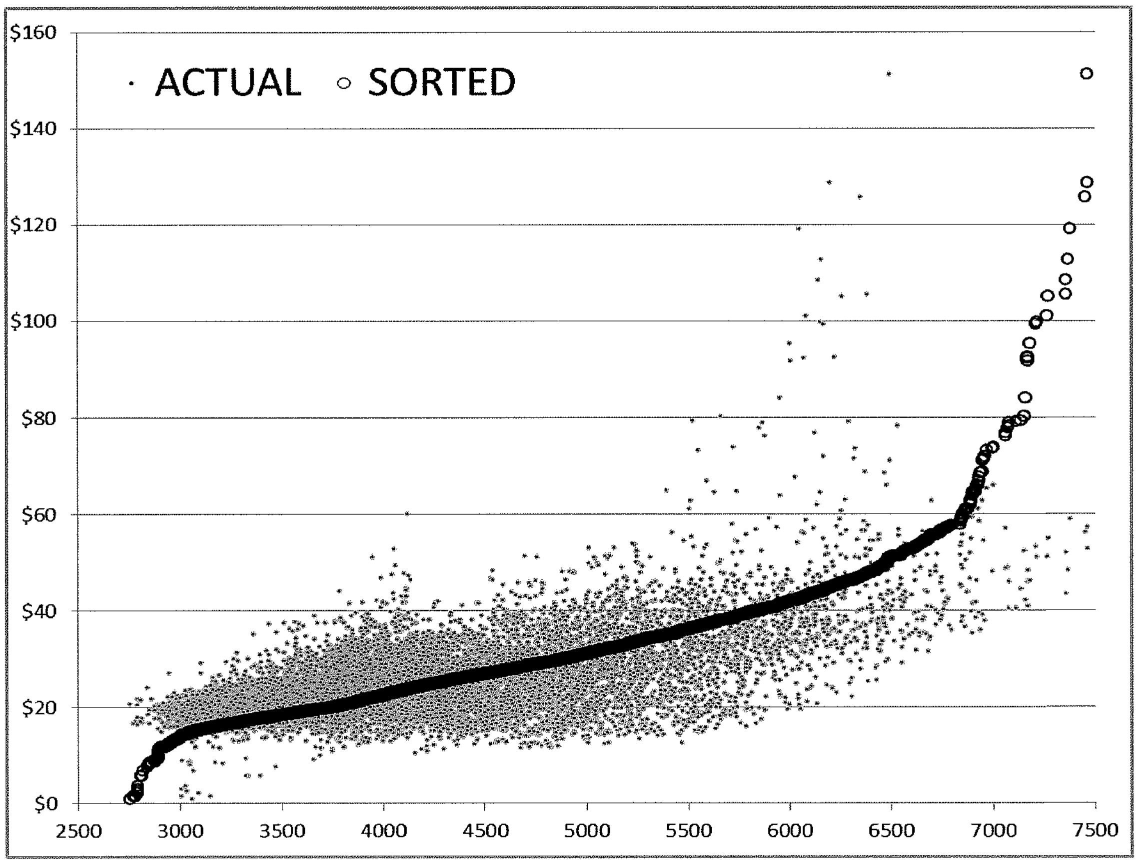
	Max Price	Max Load
2012	7/17/12	6/29/12
2013	7/17/13	9/10/13
2014	1/28/14	8/25/14

	Min Price	Min Load
2012	6/10/12	3/25/12
2013	9/18/13	5/26/13
2014	7/5/14	5/4/14

I also performed a simple correlation calculation to show the poor correlation between price and load. For this calculation, I utilized the Day-Ahead LMP for the AMMO.UE CpNode (the pricing node in the MISO market used to settle Ameren Missouri's load) and the actual Day-Ahead cleared amounts for each hour for the period January 1, 2012 through December 19, 2014 (the most recent data available on the date of my collection). I then did the same calculation using prices for CpNodes applicable to the Labadie, Meramec, Rush Island, and Sioux Energy Centers. These results clearly show the actual correlation between load and price is significantly lower than the over 95% value that Staff's methodology would yield.

Load	59.8%
Labadie	57.5%
Meramec	59.1%
Rush Island	58.5%
Sioux	59.0%

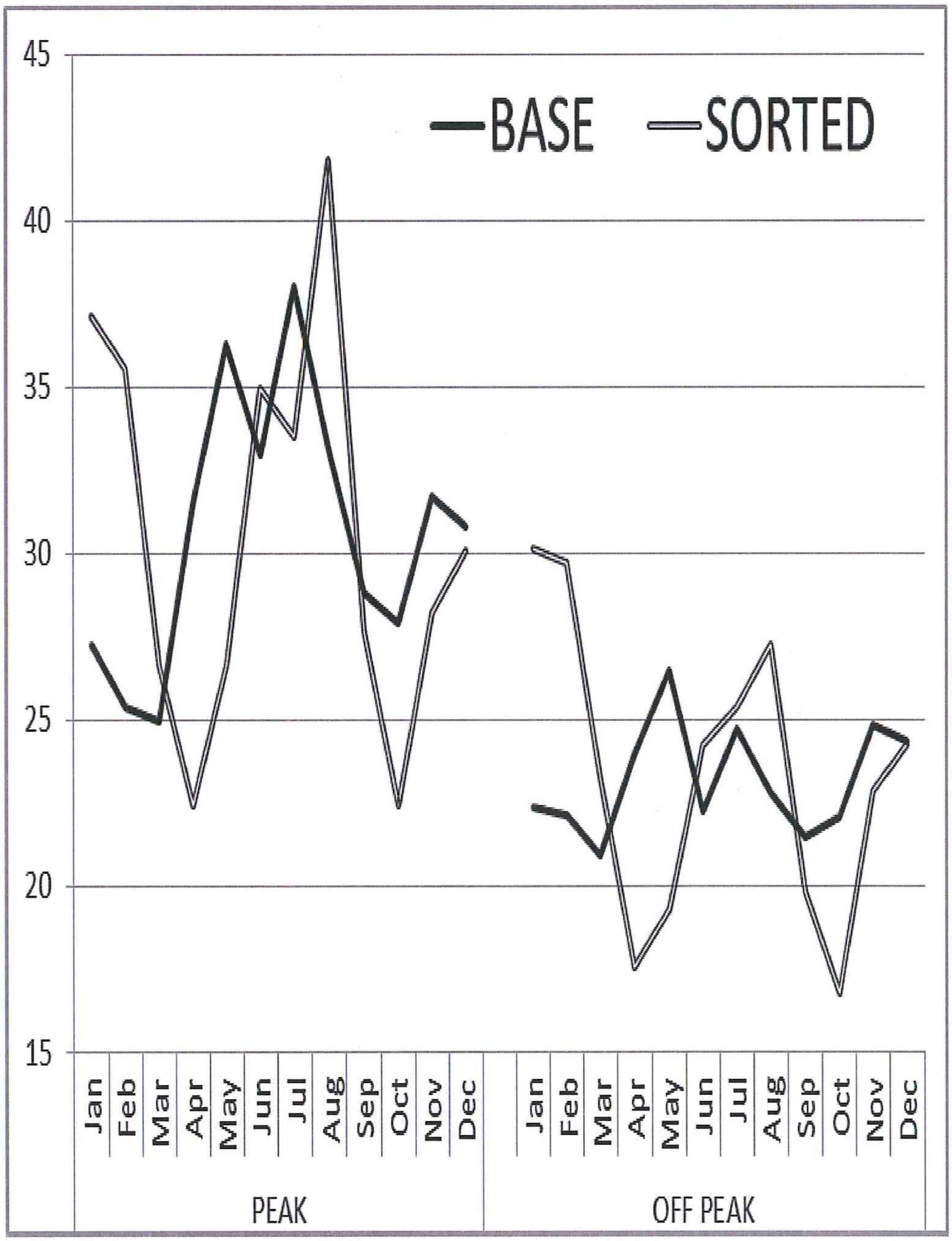
Additionally, I prepared a simple chart of actual day-ahead LMPs and load which compares that distribution to what is obtained when using Staff's sorting methodology. As is shown in the chart below, actual day-ahead prices vary considerably at every load level.



Q. Does Staff's sorting methodology materially change the distribution of prices throughout the year versus what was actually experienced in a given test period?

A. Yes. I prepared a simple graphic that highlights how much actual block price shapes are impacted by Staff's sorting methodology. To simplify, I used the same

Day-Ahead LMP and load clearing referred to above. As this chart shows, Staff's sorting methodology has a dramatic effect in every month and peak period of the year, with the exception of December Off-Peak. Some of the months have their block prices shifted by approximately $10/MWh – as high as a 40% difference.



Q. Does Staff's sorting methodology yield a reasonable result?

A. No. As shown above, Staff's sorting methodology fundamentally changes the distribution of prices during the year in a manner which does not reasonably represent a normalized year.

Q. What recommendations do you have regarding Staff's methodology?

A. In addition to removing the extraneous CpNodes from the initial data set, I recommend Staff's methodology be modified by; 1) weighting the hourly day-ahead LMP's by the actual day-ahead generation awards, 2) not adjusting prices below $5 and 3) by eliminating the final two steps of the process whereby the loads and prices are artificially aligned (highest to lowest).

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

Q. Has Ameren Missouri discussed a possible resolution of the areas of disagreement with Staff and the MIEC that have been discussed in your testimony and that of Mr. Haro?

A. Yes. Ameren Missouri has discussed the possible resolution of five issues with which we have identified disagreement with the direct testimony of Staff and/or the MIEC. These are the method in which normalized market prices are developed and outside of the model adjustments to off-system sales revenues to reflect costs and revenues for real time load and generation deviations, bilateral margins and swap margins and real time RSG-MWP margins. Ameren Missouri believes we have reached an agreement in principle with Staff and the MIEC on these issues, and will continue to work with these and other interested parties to achieve a stipulation and agreement regarding Net Base Energy Costs incorporating these items.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	Case No. ER-2014-0258

AFFIDAVIT OF MARK J. PETERS

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

Mark J. Peters, being first duly sworn on his oath, states:

1. My name is Mark J. Peters. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Manager, Asset & Trading Optimization in the Corporate Planning Department.

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 21 pages, and Schedule(s) N/A, 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.

[signature]
Mark J. Peters

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

Beckie J. Eaves
Notary Public

My commission expires:

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