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Witness:	Andrew Meyer
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

DIRECT TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
July 2016

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DIRECT TESTIMONY

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Andrew Meyer and my business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom are you employed and what is your position?

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") as Director, Asset Management & Trading.

Q. Please describe your educational background and employment experience.

A. In May of 1997, I received a Bachelor of Science degree in Business Administration (Emphasis in Management) and Agricultural Economics from the University of Missouri – Columbia. I began my career with Continental Grain Company, working as a Commodity Merchandiser from 1997 to 1999. In this role, I purchased grain from producers and grain cooperatives, blended for quality, and arranged barge transportation for re-sale of the grain in the Southeast grain export market. My employment with Ameren Energy, Inc., which at the time was an Ameren Corporation subsidiary, began in April of 1999. Later, Ameren Energy, Inc.'s functions were assumed by Ameren Missouri. From 1999 to 2008, I performed several roles in the trading function at Ameren Energy, Inc., and later at Ameren Missouri, including long-term energy and capacity position management, congestion hedging, analysis, real-time trading, and scheduling. In 2009, I joined Ameren Services Company as a Senior Market & Policy Consultant in the Corporate Planning department. My primary responsibility in this role was to participate in the Midcontinent Independent System Operator, Inc. ("MISO") stakeholder forums on behalf of Ameren Missouri. In October of 2009, I returned to Ameren Missouri as Managing Supervisor, Trading. My responsibilities included long and short-term energy sales management, capacity marketing, congestion hedging, full and partial requirements contract management, and real-time energy trading. In 2014, I also assumed management of gas supply for generation, and my title was changed to Sr. Manager, Trading. On May 1, 2015, I was promoted to Director, Asset Management & Trading.

Q. What are your responsibilities in your current position?

A. As Director, Asset Management & Trading my responsibilities are divided into two areas: (i) Real-Time Operations, and (ii) Trading and Gas Supply. My main role is providing guidance, oversight and coordination of activities in these areas. I am responsible for establishing strategy, goal setting, staffing, budgeting, management reporting, and other tasks associated with these functions.

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

A. The first purpose of my direct testimony is to establish the levels of net off-system sales revenues ("OSSR") and the normalized capacity component of purchased power expense to include in the revenue requirement utilized for the purpose of setting Ameren Missouri's rates. Both of these items are components of net base energy costs ("NBEC"), which are used in the calculation of the base factor ("BF") in the

Company's fuel adjustment clause ("FAC"). The calculations of NBEC and BF are discussed in the direct testimony of Ameren Missouri witness Laura Moore. The determination of the modeled fuel (including transportation) and net purchased power components of NBEC are discussed in the direct testimony of Ameren Missouri witness Mark Peters.

The second purpose of my testimony is to demonstrate the continued volatility and uncertainty of market drivers which impact the costs and revenues tracked in the FAC.

Q. Please summarize your testimony and conclusions.

A. The focus of the first part of my direct testimony is on the methodology and source data for the calculation used to determine the appropriate level of normalized net off-system sales revenues and the normalized capacity component of purchased power expense. Ameren Missouri's reported net off-system sales are primarily comprised of energy, capacity, and ancillary services sales. Energy sales are driven in large part by Ameren Missouri's load serving obligation to its retail customers, the availability of its generation resources, and the incremental cost of operating its generating resources relative to the market prices for energy. To the extent the level of net off-system sales experienced during the test year is not the result of normal conditions, or does not properly reflect known and measurable changes, adjustments are necessary as outlined in more detail below.

The PROSYM production cost model (the operation of which is addressed in Mr. Peters' direct testimony) is utilized to determine the normalized level of the energy component of net off-system sales. I determined the appropriate level of normalized net off-system sales revenues using these results, and values for the remaining components of net off-system sales revenue as specified in Factor OSSR in the Company's FAC tariff. I describe these in more detail later in my testimony. I separately determined the appropriate level of the capacity cost component of purchased power expense as specified in Factor PP in the FAC tariff.

Normalized off-system sales revenue and the normalized capacity cost component of purchased power expense are used in determining the Company's revenue requirement and used in the calculation of the BF.

In the second portion of my testimony, I will demonstrate that the main FAC components – namely fuel, transportation, net purchased power, net energy sales and net capacity sales - remain volatile and uncertain. Since cost is a function of both price and volume, volatility and uncertainty in either the price or the volume necessarily results in volatility and uncertainty in the cost (or revenue) of these various FAC components.

II. NET OFF-SYSTEM SALES REVENUE AND CAPACITY COMPONENT OF NET PURCHASED POWER

Q. What elements are included in your net off-system sales revenue recommendation?

A. In the context of this proceeding, I use the term "net off-system sales revenue" in reference to those revenues and costs recorded in Federal Energy Regulatory Commission ("FERC") Account 447 arising from Ameren Missouri's trading activities, including those amounts associated with purchasing energy from the MISO market to meet Ameren Missouri's load requirements, which are netted against revenues from Ameren Missouri generating units.

The net revenue from these activities comes from six primary components: (i) energy sales revenues; (ii) capacity sales revenues; (iii) ancillary services revenues; (iv) margin associated with real-time revenue sufficiency guarantee make-whole payments ("RSG MWP"); (v) other miscellaneous MISO revenues; and (vi) physical bilateral transaction and financial swap margins. As noted, the energy sales component is the product of modeling using the Company's PROSYM model, which is run under Mr. Peters' direction. The remaining components are based upon Ameren Missouri's historical capacity sales revenues, ancillary services revenues, real-time RSG MWP margins, miscellaneous MISO revenues, and physical bilateral transaction and financial swap margins, taking into account known and measurable changes.

Q. What is the appropriate level of net off-system sales revenues to include in Ameren Missouri's revenue requirement and to set the NBEC?

A. I determined that the level of net off-system sales revenues that should be included in Ameren Missouri's revenue requirement and used to set the NBEC is approximately $525.5 million per year. This total is comprised of the following components, each of which I address in more detail later in my testimony:

1) $260.1 million of net energy sales revenues;

2) $243.8 million in gross capacity sales revenues;

3) $6.4 million of ancillary services revenues;

4) $1.3 million of real-time RSG MWP margins;

5) $310 of other miscellaneous MISO revenues;

6) $8.8 million and $4.4 million, respectively, for physical bilateral transaction and financial swap margins; and

7) $0.7 million related to load and generation forecasting deviation, which Mr. Peters addresses in his direct testimony.

Q. What is the appropriate level of the capacity component of purchased power expense to include in Ameren Missouri's revenue requirement and to set the NBEC?

A. I determined that the level of the capacity component of purchased power expense that should be included in Ameren Missouri's revenue requirement and used to set NBEC in the FAC is $198.9 million per year.

A. <u>Energy Sales Revenues</u>

Q. How was the normalized level of net off-system sales of energy determined?

A. In accordance with well-established past practice, modeling using Ameren Missouri's PROSYM model was used so that net off-system sales more reasonably reflect a normal year, since no particular 12-month period reflects a normal year. The test year is affected by its particular weather, generation outages, fuel costs, transmission constraints, and energy prices, among many other things. In any given year, weather, prices, unit availability, and load characteristics can vary greatly from normal. Utilizing only actual data from one specific year in setting the revenue requirement would fail to account for this volatility. In order to assure that net off-system sales revenues utilized to determine the Company's cost of service and NBEC are consistent with normalized conditions, it is necessary to determine the energy component of net off-system sales based on production cost modeling using normalized loads and generation-related inputs. Modeling has been used by both the Company and the Commission Staff to determine the energy component of net off-system sales revenues in all of the Company's general rate proceedings in recent history.

Q. How are net off-system sales of energy derived from the PROSYM model's output?

A. PROSYM simulates Ameren Missouri's interactions with the market. As noted in Mr. Peters' testimony, Ameren Missouri is a market participant within the MISO markets. Ameren Missouri purchases energy for its entire load from the MISO market and it separately sells all of the megawatt-hours ("MWhs") generated by its generating units into the MISO market. In accordance with FERC requirements, however, these amounts are netted against each other for each hour. This netting results in the recording of either a net off-system sale or a net power purchase for that hour depending on whether the volume of total sales exceeds total purchases (net off-system sale) or if the volume of total purchases exceeds total sales (net power purchase). The results of the Company's modeling reflect netted amounts for both off-system sales and purchased power.

The model utilizes the inputs described in Mr. Peters' testimony to simulate the dispatch of Ameren Missouri's system. In any given period, the model dispatches available generation that has dispatch costs below the hourly market price for energy. In any period where Ameren Missouri has a load requirement in excess of available generation that has a dispatch cost below the hourly market price for power, the model reports a net purchase equal to that difference. In any period where Ameren Missouri has a load requirement less than available generation that has a dispatch cost below the hourly market price for power, the model will report a net sale equal to that difference.

The simulated net off-system sales revenues are determined based on the hourly market price for the MWhs reported as net sales. The model effectively assumes that the dispatch of Ameren Missouri's generation is "perfect"; that is, for example, it assumes that available generation units will always operate at their economically-optimal level in each hour. The model does not assume any congestion or losses between generation and load (when in fact there often are congestion and losses). The model also ignores the fact that load and generation differ in real time from the previous day's market clearing.

Q. What market energy price assumptions were utilized to model the dispatch of Ameren Missouri's generation?

A. The price assumption used to model dispatch was the average hourly energy prices for the 36-month period ending December 31, 2016, adjusted for the Polar Vortex weather anomaly, which I discuss below. These prices averaged $23.78 per MWh.

Market energy prices for the period of January 1, 2014 – March 31, 2014 have been replaced with the average prices for the applicable peak period, by month, from January of 2015 to March of 2015 and January of 2016 to March of 2016 (e.g., the 5x16 period for January has been replaced by the average of the 5x16 period for January of 2015 and January of 2016). This adjustment is being made to account for the severe weather anomaly which has been commonly referred to as the "Polar Vortex" and is consistent with the adjustment made in File No. ER-2014-0258.

The energy prices for the period of April 1, 2014 through April 30, 2016 are the weighted average day-ahead locational marginal prices ("LMPs") in the MISO energy market actually received at Ameren Missouri's generating units. Consistent with past practice, the energy prices for the remaining months are basis-adjusted forward energy prices[1]. These serve as a reasonable proxy until they are replaced with actual energy prices as part of the true-up in this case.

Q. Please explain why you chose to utilize day-ahead LMPs at the generator nodes.

A. Our use of the day-ahead LMPs is consistent with longstanding practice. As mentioned before, the PROSYM model simulates the dispatch of the Company's generators based on a series of inputs. This dispatching logic is similar to the one followed by the MISO to determine its day-ahead commitment of all of the generators in its footprint. The result of the MISO process is, among other things, the determination of individual LMPs for each generator. It is most appropriate to use the historical prices applicable to Ameren Missouri generation for the day-ahead markets since these are the prices that determined the generation levels that produced the vast majority of Ameren Missouri's historic net off-system sales. In fact, day-ahead prices determine about 97% of Ameren Missouri's generation commitment and dispatch.

Q. You previously indicated that the production cost model assumes that there is no congestion or losses between generation and load when in fact there often are congestion and losses. Is this a reasonable assumption to use in the model?

A. Yes. This assumption is as reasonable as any change to NBEC which would result from attempting to capture such differences in the model, has already been accounted for by including normalized expenses for losses and congestion, offset by

[1] These forward energy prices are taken from a combination of broker quotes and published data for trading activity at the Indiana Hub, a well-recognized Midwest energy trading market. The forward energy prices were adjusted for a calculated basis differential that exists between prices at the location of the Indiana Hub and the prices that are actually realized at the Ameren Missouri generating units.

Auction Revenue Right ("ARR") and Financial Transmission Right ("FTR") revenues in the calculation of NBEC.

B. <u>Capacity Sales Revenues and Capacity Costs</u>

Q. What is the level of gross capacity sales revenues on an annual basis that is appropriate to include in total net off-system sales?

A. I have determined that $243.8 million is the appropriate amount to include as gross capacity sales revenues. I calculated this value using actual capacity sales for the MISO 2016-17 planning year (6/1/16-5/31/17). This period was chosen as these are the actual contracts which will be in place as of the date that rates will go into effect. The Company does not have additional capacity revenues to sell for this period, nor does it have any unmet capacity requirements for that period. These revenues represent actual transactions which have already been executed. As such, they are a known and measurable change to the test year capacity revenues.

Q. What is the level of gross capacity purchase expense on an annual basis that is appropriate to include in the capacity component of purchased power expense?

A. I determined that the level of the capacity component of purchased power expense that should be included in Ameren Missouri’s revenue requirement and used to set NBEC in the FAC is $198.9 million per year.

As I did with capacity revenues (discussed above), I calculated this value using known and measurable capacity purchases for the 2016-2017 MISO planning year.

Q. Did you make an adjustment to your calculation of the capacity component of purchased power expense for the change in Industrial Aluminum Smelter (“IAS”) class demand?

A. No. Such an adjustment is neither necessary nor appropriate as Ameren Missouri did not include any IAS demand in the load forecast provided to the MISO for the planning year 2016-2017 capacity auction and therefore did not purchase any associated capacity.

Q. What is the net impact of the gross capacity sales revenues and gross capacity sales purchase expenses on NBEC?

A. Netting capacity sales against capacity purchases results in net revenues used in determining NBEC of $44.9 million, which lowers the NBEC.

Q. What was the corollary amount used to set NBEC in File No. ER-2014-0258?

A. $5.8 million.

Q. Why is Ameren Missouri purchasing capacity if it owns sufficient generation to meet the resource adequacy requirements imposed by MISO's tariff?

A. Under MISO's tariff, Ameren Missouri must meet certain resource adequacy requirements during each planning year (June to May each year). As discussed below, it has two basic options for doing so, one of which – self-scheduling – involves purchasing capacity in MISO's annual capacity auction. Ameren Missouri has chosen the self-scheduling option as it provides benefits to our customers that are equal to or greater than the alternative.

Q. Please elaborate.

A. Under MISO's tariff, load-serving entities ("LSE") have the option to meet MISO's resource adequacy requirements either by submitting a Fixed Resource Adequacy Plan ("FRAP") in advance of the MISO capacity auction or, as noted, by self-scheduling their resources. A FRAP allows the LSE to essentially remove its generation and load from the capacity auction clearing process. However, if the LSE's FRAP includes resources from a zone other than the zone in which its load is located and if the price of capacity in the load zone is higher than the price of capacity in the resource zone, then the LSE will incur what MISO terms a zonal deliverability charge (i.e., it will receive a bill for the price difference). If the price difference is flipped – the price in the resource zone is higher than in the load zone – by using the FRAP, the LSE forfeits the ability to enjoy the benefit of the higher resource zone price. Since Ameren Missouri has significant generation capacity in a resource zone (in Illinois) that is different than the zone where its load is located, it must consider the potential detriment of using the FRAP option as a means to meet MISO's resource adequacy requirements.

When self-scheduling is used, the LSE offers its resources, up to the megawatt ("MW") amount needed to meet its load obligations, at $0.00, ensuring that at least that amount of its resources will clear (i.e., be sold) in the capacity auction. This allows the LSE to retain the benefit of having the resource zone clear at a price higher than the load zone, while leaving it in the same position it would have been in had it utilized a FRAP when the opposite occurs.

Q. Can you provide an example of when the price in the zone where Ameren Missouri resources are located was higher than the zone where Ameren Missouri's load is located, producing a benefit for customers that would not have been available had Ameren Missouri used a FRAP?

A. Yes. In MISO's capacity auction for the 2015-2016 planning year, zone 4, [essentially central and southern Illinois, where many of Ameren Missouri's combustion turbine generator ("CTG") units are located] cleared at a price of $150/MW-day, while zone 5, (where Ameren Missouri's entire load and the balance of its generation are located) cleared at a price of only $3.48/MW-day. Ameren Missouri's load obligation in zone 5 exceeded available resources in zone 5 by 536.1 MW. Because Ameren Missouri used a self-schedule instead of a FRAP, its 536.1 MW shortfall in zone 5 was purchased from the MISO capacity market at $3.48/MW-day for a cost of just $0.7 million but Ameren Missouri was able to sell the same amount of generation in zone 4 at a price of $150/MW-day producing revenue of $29.4 million. The net of those two sums produced a benefit for customers of $27.3 million[2] above and beyond the revenue received for the balance of Ameren Missouri's excess capacity sales. Had Ameren Missouri chosen to use a FRAP, customers would not have enjoyed that additional benefit.

C. Ancillary Services Revenues

Q. What level of annual ancillary services revenues did you determine was appropriate to include in total net off-system sales?

A. $6.4 million. This level was determined by normalizing ancillary services revenues from the test year. These revenues are subject to true-up.

D. Revenue Sufficiency Guarantee Make-Whole Payment Margins

Q. What level of real-time revenue sufficiency guarantee make-whole payment margins did you determine was appropriate to include in net off-system sales?

A. Approximately $1.3 million. This level of margin was determined by taking the difference between the as-offered cost and the actual fuel cost for Ameren

[2] After applying the 95/5 sharing mechanism.

Missouri's CTGs for those hours in which an RT RSG MWP was received for a given unit for the 12 months ended March 31, 2016. This amount is subject to true-up.

E. Miscellaneous MISO-related Revenues

Q. What are the miscellaneous MISO-related revenues?

A. These are receipts related to inadvertent energy from MISO, and they totaled $310 during the test year. This amount is subject to true-up.

F. Physical Bilateral Contract and Swaps

Q. What are the physical bilateral transaction and financial swap margins?

A. Physical bilateral transactions and financial swaps are hedging mechanisms used to mitigate some of the volatility from OSSR, but they do not replace the off-system energy sales themselves. Physical bilateral transactions and financial swaps margins of $8.8 million and $4.4 million, respectively, should be utilized for this component of net off-system sales revenues. These amounts are subject to true-up.

Q. How are the margins for physical bilateral transactions and financial swaps calculated?

A. The margins for physical bilateral transactions and financial swaps are calculated as a margin derived from the difference between the sales price and the settling index. This is the same approach utilized by the parties in the Company's last rate proceeding.

For the physical bilateral transactions, the energy and the associated fuel has already been accounted for in the production cost model PROSYM. However, the model prices the energy at the day-ahead spot market price and not the price at which the physical bilateral transaction was made. The margin calculation accounts for that difference.

The margin was calculated by taking the difference between the actual price received and the price that would have been received had the transaction settled at the spot market for the CpNode[3] specified by the transaction and multiplying that difference by the volume. (For a bilateral purchase, the calculation is reversed – it is a comparison of the fixed price paid to the spot price which would have been paid).

III. VOLATILITY AND UNCERTAINTY OF MARKET FACTORS IMPACTING THE MAIN FAC COMPONENTS

Q. Do the market factors impacting various cost components of the FAC continue to be volatile and uncertain?

A. Yes, all of the costs components of the FAC – fuel, purchased power, transportation and off-system sales – continue to be volatile and uncertain. This includes coal, natural gas, coal transportation, transmission charges, energy, ancillary services and net capacity revenues. This is because the costs of all of these components are a function of both price and volume. Both price and volume can be significantly impacted by what is occurring in the markets.

It must be kept in mind that the volume of our fuel costs (which includes significant coal costs), off-system sales and spot market prices for fuel commodities and energy are inexorably linked together. The volume of coal (and natural gas) which Ameren Missouri consumes in a given year is a function of the market dispatch of its generating units. That dispatch in the MISO market is a function of the offer price of the

[3] A "CpNode" is a pricing location within MISO's market.

unit (based on its incremental fuel cost) and the market price available to the unit for a given hour.

Any volatility or uncertainty in either the incremental fuel cost or the market price available to the units will necessarily result in volatility and uncertainty in the unit output which impacts fuel consumption, net purchased power expense and net off-system sales revenues.

Q. Is the market price for energy volatile?

A. Yes. The market price for energy remains volatile and is expected to remain so. While increased natural gas supply and increased installations of wind and other renewable resources have applied downward pressure on electrical energy prices (particularly in the off-peak periods), actual and projected retirement announcements for coal-fired resources resulting from environmental regulations have an opposite and much less certain impact, particularly given the U.S. Supreme Court's recent stay of the Clean Power Plan. Natural gas prices, while currently lower than in recent years, continue to display volatility and uncertainty. For example, the State of New York officially banned fracking in June of 2015. Questions continue to be raised in other areas, including in Oklahoma, about the geologic impacts of fracking, which has been linked to increased seismic activity in and near Oklahoma. While I am not suggesting that this means that fracking will be banned elsewhere, it does highlight the uncertainty that exists regarding what natural gas prices may be in the future. When we consider the dramatic downward movement that we experienced as a result of fracking, it is not too difficult to imagine what the impact would be if more jurisdictions were to ban or limit use of the technology.

Q. Is the market price of coal volatile?

A. Yes, the market price of coal remains volatile. As noted, Ameren Missouri does have fixed price contracts for coal purchases currently in place and thus has price hedged part of its expected coal purchases. However, as also noted, the dispatch cost of our coal-fired units is based on the spot price of coal, not the accounting cost which reflects the contract price. As noted above, fluctuations in the price of coal affect our unit dispatch which affects the volume of coal that is burned. The spot price of coal is not driven solely by domestic market factors, including environmental regulations and increased energy efficiency, but it is also driven in large part by external factors such as the demand from other nations. As the following chart from the Energy Information Administration ("EIA") illustrates, the volume of coal exported from the United States has decreased greatly over the past three years – virtually reversing the increases from the prior three years.

When this change in exports is broken down by continent we can see that the three largest markets for U.S. exports in 2014 all saw dramatic decreases in the amount of U.S. coal which they imported.

EIA - U.S. Coal Exports (short tons)

	2014	2015	Change	%
North America	8,885,158	7,953,144	-932,014	-10%
South America	7,709,562	5,690,774	-2,018,788	-26%
Europe	39,998,485	29,708,650	-10,289,835	-26%
Asia	15,647,850	14,776,901	-870,949	-6%
Australia	870	482	-388	-45%
Africa	2,739,088	529,203	-2,209,885	-81%
Total	74,981,013	58,659,154	-16,321,859	-22%

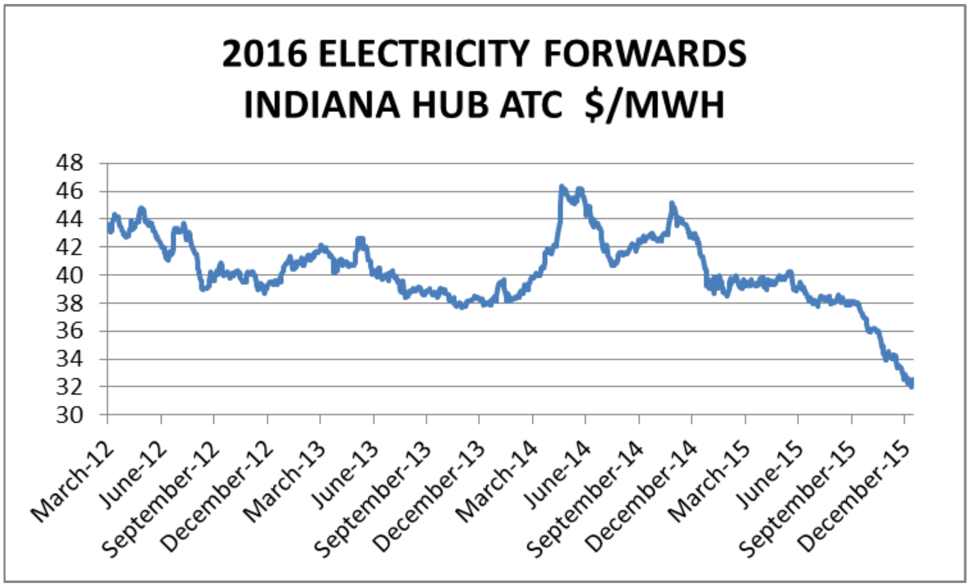
http://www.eia.gov/coal/production/quarterly/xls/t7p01p1.xls

Q. Can you illustrate the volatility of market factors which impact the dispatch of Ameren Missouri's generators?

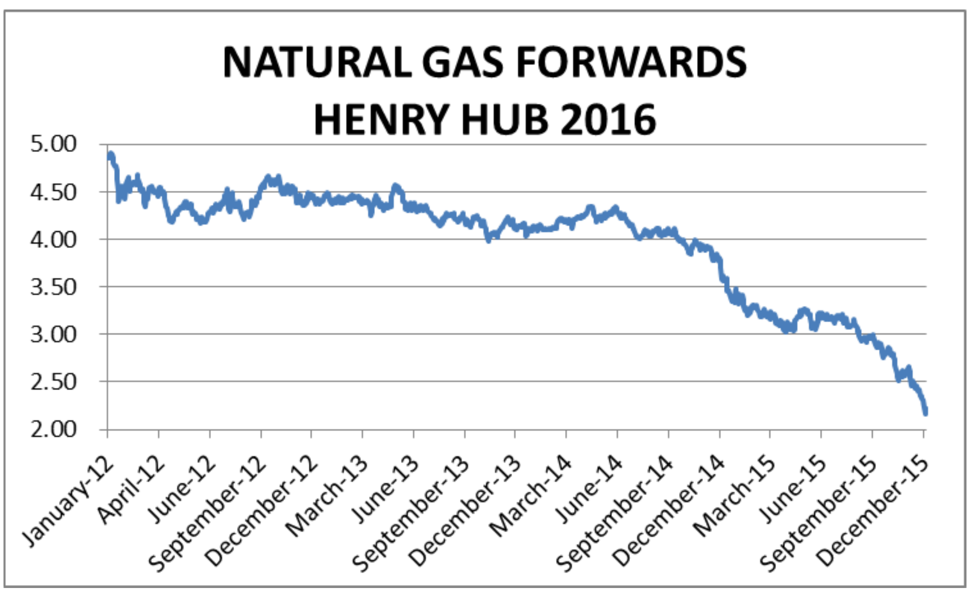
A. Yes. I have prepared three simple graphs that show that prices for energy, coal and natural gas, all of which impact the dispatch of our generation units, remain volatile and uncertain. Each of these graphs represents the calendar year forward contract for 2016, over the prior three years.[4]

[4] For example, in March 2012 the forward price for a 2016 electricity contract was about $44/MWh. In December 2015 the forward price for a 2016 electricity contract was about $32/MWh.

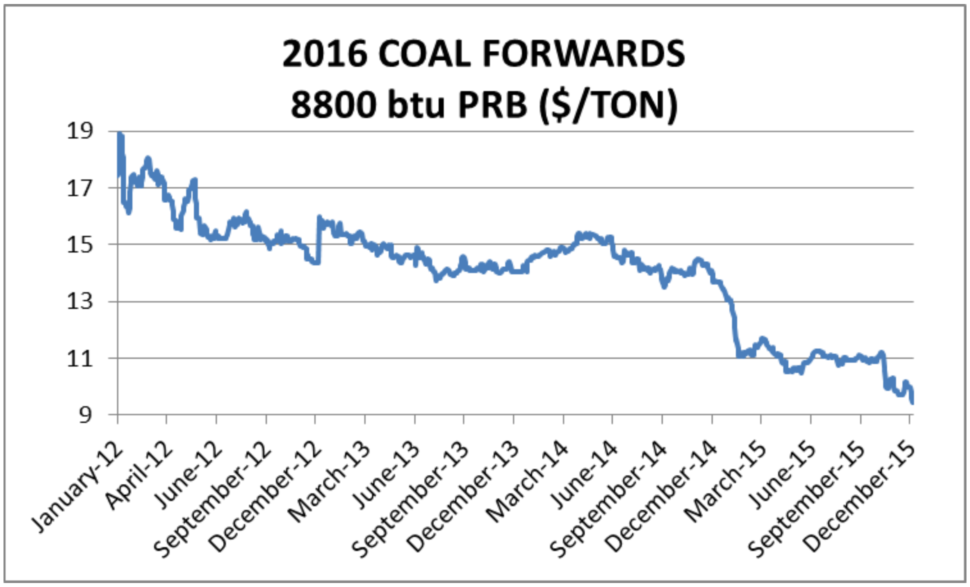
Graph 1



Graph 2



Graph 3



As I noted earlier, market energy and fuel prices all impact the dispatch of Ameren Missouri's generators. If market energy prices rise faster than increases in the market price of the coal or natural gas fuel burned by the generator, we would expect to see the volume of generation output (and associated fuel consumption) to increase. If market prices rise slower than the rate of increases in the market price of the coal or natural gas fuel input for a generator, we would expect to see the volume of generation output decrease. Of particular interest to this discussion is the impact of wind resources on the prices available to coal-fired generation in the overnight hours. The lowering of off-peak prices frequently results in having such generators dispatched near unit minimums, and in the case of our Meramec Energy Center units, is more likely to result in the units being placed in reserve shutdown.

Q. Has Ameren Missouri experienced significant changes in its coal costs and volumes in recent years?

A. Yes. Looking at total output and total coal cost (total coal costs consist of the cost of the coal itself and rail transportation costs to get it to the plants, including rail fuel surcharges) for our coal-fired generators from 2011 through 2015, we can see very large differences between the years. The MWh change from 2011 to 2012 alone was 14%, while 2015 saw a 9% decrease from 2014. Coal costs from 2012 to 2013 increased 11%, while they decreased 8% in 2015 from 2014. While the year-on-year changes in the other years may not have been as dramatic, they remain significant. As the table below shows, the lowest year-on-year absolute dollar change in coal cost at the coal-fired units was **over $34 million**, but over this period there have been reductions as high as approximately $61 million and increases as high as approximately $67 million. On a percentage basis, in just the five years included in the table below, we have seen volume changes between 2% and negative 14% and cost changes between 11% and negative 8%.

	MWh	$	Mwh Change	%	$ Change	%
2015	30,122,113	$681,278,498	-2,937,618	-9%	($61,272,992)	-8%
2014	33,059,731	$742,551,490	-269,970	-1%	$40,153,790	6%
2013	33,329,701	$702,397,700	907,887	3%	$67,187,949	11%
2012	32,421,814	$635,209,751	-5,083,114	-14%	($34,567,345)	-5%
2011	37,504,928	$669,777,096				

Q. Does Ameren Missouri face price uncertainty related to coal?

A. Yes, it does. While it is true that in the near-term the Company has relatively greater price certainty for its delivered coal costs than it may have for other commodities, the volume of coal that is price hedged declines significantly in the next few years. Consequently, the Company has increasingly less certainty regarding the price of its coal in the future. Moreover, the Company also faces price uncertainty related to rail surcharge cost (basically the railroad companies' equivalent of an FAC for the diesel fuel used to power their train engines).

When we consider that Ameren Missouri has burned between 17.6 and 22.1 million tons of coal a year between 2011 and 2015, and that each ton must necessarily be transported from the mine to our generating facility, it is obvious that even small changes in the price of either the commodity or the associated transportation services can have a large impact on our cost.[5] Graph 3 above illustrates that the forward price of 2016, 8800 btu PRB coal fell almost 50% ($9/ton) across four years.

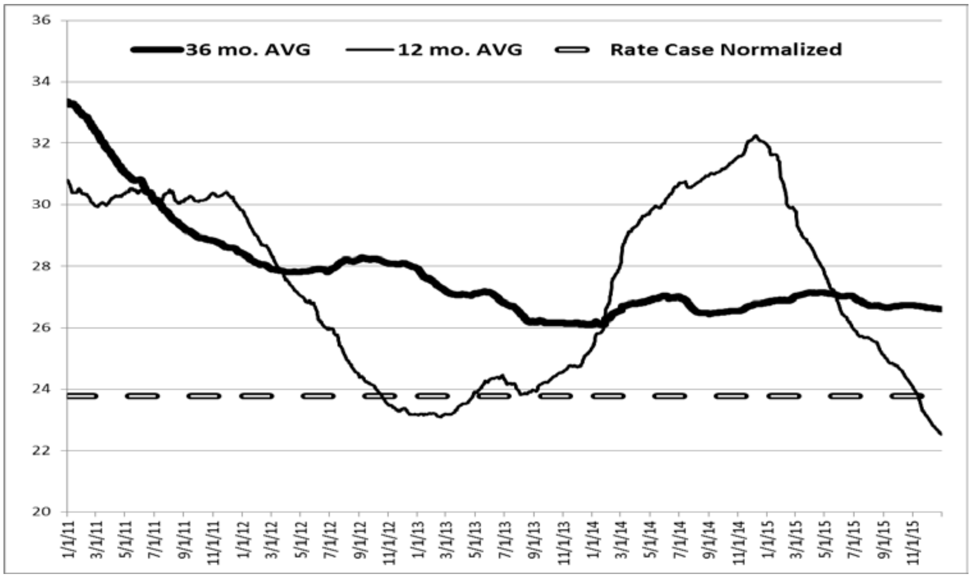
Rail transportation costs are a function of supply and demand for rail services. While reduced coal demand nationwide may place downward pressure on rail prices, competing rail uses may more than offset this.

We simply do not know with any certainty what the price of either the coal commodity or associated transportation will be for any specific volumes until we have actually executed an agreement with a supplier.

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

A. Yes. The following graph of the daily average LMPs for our coal-fired generators illustrates that both the rolling one-year and three-year historical average day-ahead LMP have varied greatly over the past five years.

[5] At approximately 17 to 22 million tons per year, just a $1 price change amounts to around $20 million.



Q. What is the significance of the line labeled "Rate Case Normalized"?

A. This line is the normalized “around-the-clock” energy price of $23.78. This amount has been calculated for our direct filing using three years of generation weighted day-ahead LMPs and adjusted to account for the Polar Vortex anomaly.

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

A. The equivalent value in the last rate case was $25.50.

Q. Are net off-system sales revenues related to energy sales volatile and uncertain?

A. Yes. As previously discussed, the energy sales portion of net off-system sales revenues are the result of having a load requirement clear in a given hour that is lower than the amount of generation resources cleared in the same hour. In accordance with FERC regulations, when this occurs, the generation sales are netted against the load purchases. The amount of generation which clears in a given hour is a function of volatile and uncertain fuel and market prices. The amount of load that clears is a function of volatile and uncertain weather and customer behavior. Accordingly, with the volume of generation and the volume of load being volatile and uncertain, it follows that the reported volume of net off-system sales of energy is also volatile and uncertain. Additionally, the price of the energy portion of off-system sales revenue is the market price of energy, which I have already demonstrated to be volatile and uncertain.

Q. Are net purchased power costs volatile and uncertain?

A. Yes, and for the same reasons that our net off-system sales revenues related to energy sales are volatile and uncertain.

Q. Are capacity-related revenues and costs volatile and uncertain?

A. Yes. As clearly demonstrated in the chart below, the year-on-year changes in net capacity revenues (revenues minus costs) have been very volatile, with swings as large as $51.08 million up and $16.55 million down over just three planning years.

Planning Year	($Millions) Net Cap Rev	Change	4 yr Avg.
2013-14	$ 3.45		
2014-15	$ 7.27	$ 3.82	
2015-16	$ 58.35	$ 51.08	
2016-17	$ 41.80	$ (16.55)	$ 27.72

These large swings have been driven by the volatile changes in prices for both zones 4 and 5 as shown below.

	$/MW Day		Percentage Change	
	Zone 4	Zone 5	Zone 4	Zone 5
2013-14	$ 1.05	$ 1.05		
2014-15	$ 16.75	$ 16.75	1495%	1495%
2015-16	$ 150.00	$ 3.48	796%	-79%
2016-17	$ 72.00	$ 72.00	-52%	1969%

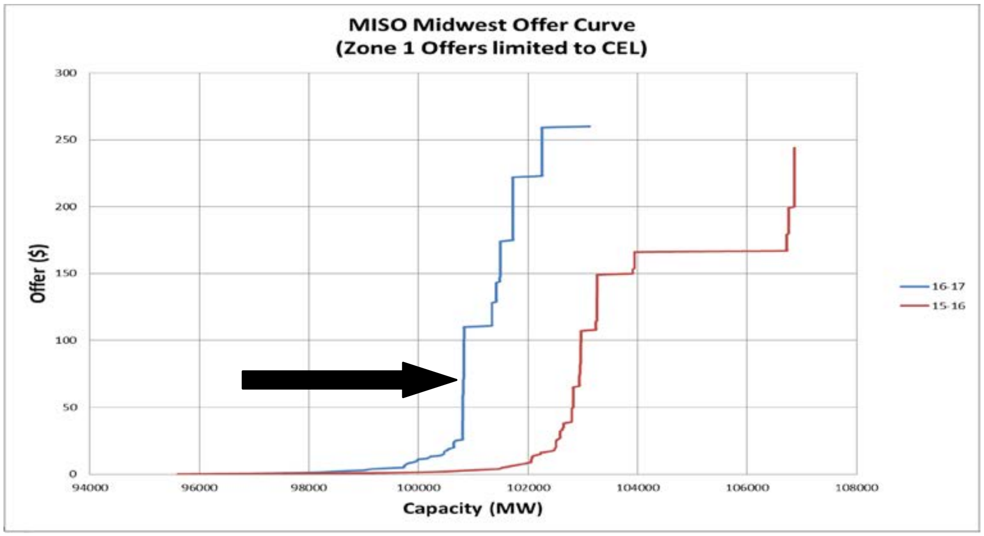
Q. Are net capacity revenues expected to remain volatile and uncertain in the future?

A. Yes. In particular, there is considerable uncertainty on the supply side for capacity going forward. In addition to potential retirements related to environmental regulations, certain independent power producers such as Dynegy and Exelon have indicated that they likely will have to retire generation units in zone 4 if neither the market nor the Illinois legislature can take action to ensure cost recovery. Furthermore, Dynegy is engaged in active efforts that could force Ameren Illinois' transmission system (including all zone 4 generators) into PJM—the regional transmission organization to the east of MISO. Any of these events, if they came to fruition, would impact the amount of available supply in MISO. This is on top of any uncertainty in future demand growth (or decline) due to the growth in energy efficiency, demand response and distributed generation (e.g., rooftop solar) programs or changes in customer behavior due to economic factors.

Q. Does the most recent MISO capacity auction provide any insight into the volatility of capacity prices?

A. Yes. The auction for the 2016-2017 planning year cleared near the midpoint of a very steep portion of the supply offer curve, as shown in the graphic below. (I have added an arrow to MISO's graphic[6] to highlight the $72 clearing price).

[6] MISO - 2016/2017 Planning Resource Auction Results Resource Adequacy Subcommittee May 4, 2016, p. 19.



When we look at the actual offer data behind this graph for the 2016-2017 planning year published by MISO[7], we can see how truly volatile this price is. I have prepared a table below using this data to demonstrate that incredibly small changes in the amount of capacity cleared in the auction would have had a significant impact on the clearing price affecting Ameren Missouri.

MW Change	% of PRMR[8]	Price	Price Change	%
-18.5	-0.018%	$26.00	-$46.00	-64%
+3.8	0.004%	$102.00	+$30.00	+42%
+555	0.546%	$128.08	+$56.08	+78%

Q. What is the significance of the last row of this table?

A. This row represents the approximate impact of the change in price that would have occurred had we not experienced the loss of the IAS load, and thus been required to include that demand in this auction.

[7] PRA 2016-2017 Detailed Report https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=224615

[8] "PRMR" stands for planning reserve margin requirement.

Q. Your table shows the impact of changes in demand. Would there also be significant changes in price due to changes in resource offers?

A. Yes. We also could have seen dramatically different results had the segment offers changed just slightly. The table below shows the offers immediately above and below the offer which established the $72/MW-day clearing price.

Offer ID	Offer Price ($/MW-Day)	Incremental Offer (MW)	Cleared Amount (MW)
O_2095_1709_16962	60.00	3.3	3.3
O_2079_1693_14709	72.00	9.0	5.3
O_2095_1709_16956	102.00	3.0	0.0

If that $72 offer had not been made (due to strategy or unit retirement), the clearing price would have jumped to $102. Alternatively, if instead of offering the segment at $72, the market participant had self-scheduled this segment at $0, the clearing price would have fallen to $60. Thus, a change in how a specific 9 MW block of capacity resources (less than 0.01% of the total offered in zones 1-7) was offered could have swung the clearing price up 42% or down 16%.

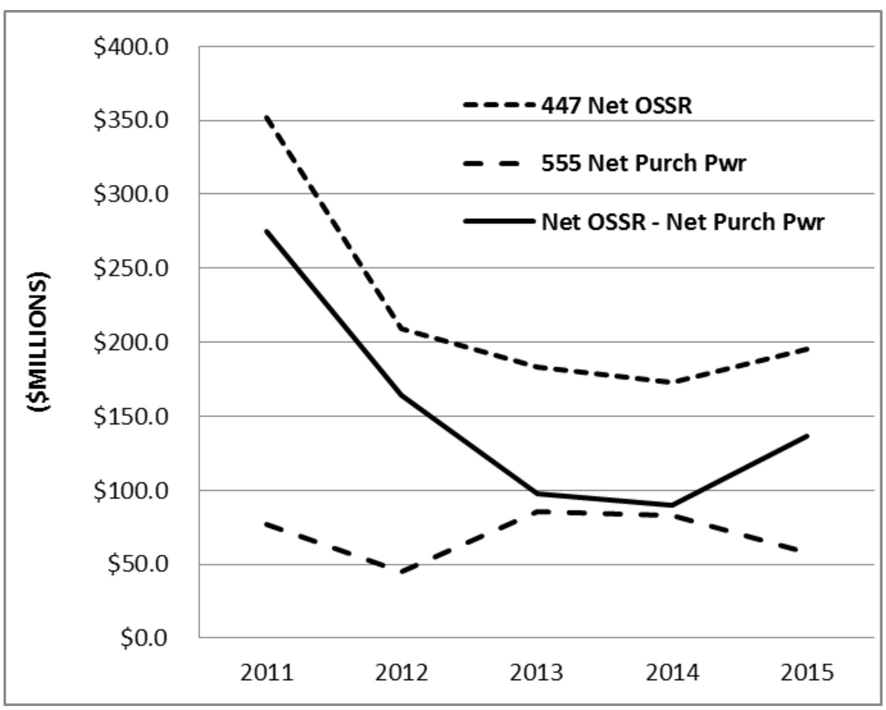
Q. What impact would price changes of the magnitudes illustrated above have on Ameren Missouri's net capacity revenues?

A. The impact on net capacity revenues of such price changes would range from -30% to +38%.

Q. Have net off-system sales revenues and net purchased power costs been stable in recent years?

A. No. As the table and graphic below illustrate, neither net OSSR recorded in FERC Account 447 nor net purchased power expense recorded in FERC Account 555 have been stable. To the contrary, they differ significantly year to year.

	FERC Acct	2011	2012	2013	2014	2015
				($ Millions)		
447 Net OSSR	447	$351.9	$209.1	$183.3	$173.2	$195.0
			$ (143)	$ (26)	$ (10)	$ 22
			-41%	-12%	-6%	13%
555 Net Purch Pwr	555	$77.1	$45.3	$85.8	$82.9	$58.3
			($31.8)	$40.6	($2.9)	($24.6)
			-41%	90%	-3%	-30%
Net OSSR - Net Purch Pwr		$274.8	$163.9	$97.4	$90.2	$136.7
			($110.9)	($66.4)	($7.2)	$46.4
			-40%	-41%	-7%	51%



Q. You addressed volatility and uncertainty in delivered coal costs (the commodity and the transportation), energy costs (for purchased power and off-system sales), and capacity. Please address volatility and uncertainty for transmission charges.

A. These charges are volatile and uncertain for the same reason that the other FAC components are uncertain – there is volatility in both the volume and the price components. The volume – the load – is impacted by weather, the economy, energy efficiency initiatives and new technologies. The transmission charges the Company must pay to obtain energy to serve its load are overwhelmingly based on the level of customer loads (demand) which, as earlier discussed, is highly uncertain. And while we know the price paid for transmission services is going up year after year, we don't know exactly by how much, in part because the price increases we expect are driven by construction costs of several billion dollars of new regional transmission lines being built within MISO's footprint. A great deal of the transmission has not yet been built, leaving significant uncertainty in what it will ultimately cost and what the resulting transmission costs will ultimately be.

Q. Does this conclude your direct 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	)	Case No. ER-2016-0179
Increase Its Revenues for Electric Service.	)	

AFFIDAVIT OF ANDREW MEYER

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

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

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

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 29 pages, and Schedules 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.

Andrew Meyer
Andrew Meyer

Subscribed and sworn to before me this 29th day of June, 2016.

Becki J. Eaves
Notary Public

My commission expires:
2-21-18

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