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Issue(s):	Fuel Adjustment Clause; Transmission Charges/Revenues Tracker
Witness:	Lynn M. Barnes
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Sponsoring Party:	Union Electric Company
File No.:	ER-2016-0179
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

DIRECT TESTIMONY

OF

LYNN M. BARNES

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
July 2016

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DIRECT TESTIMONY

OF

LYNN M. BARNES

FILE NO. ER-2016-0179

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lynn M. Barnes. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Please describe your educational background and qualifications.

A. I have a Bachelor of Science degree in Accounting from Millikin University, Decatur, Illinois. I am also a licensed Certified Public Accountant in the states of Missouri and Illinois.

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

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") as Vice President, Business Planning and Controller.

Q. Please describe your employment history.

A. I joined Union Electric Company in 1997 as General Supervisor of Financial Communications following positions at Boeing Company and Deloitte, where I began my career. I was promoted to Manager of Financial Communications in 1999, and my responsibilities included managing the financial reporting department, the regulatory accounting department, and investor relations during the period of the Company's transition from a single utility to a public utility holding company with multiple operating companies. In 2002, I transferred to Ameren Services Company's Energy Delivery Department as Controller, and in 2005 I was promoted to Director of Energy Delivery Business Services. In July of 2007, I was promoted to Controller for AmerenUE and, in October of 2007, I was promoted to Vice President, Business Planning and Controller for AmerenUE.[1]

Q. Please describe your duties and responsibilities as Vice President, Business Planning and Controller for Ameren Missouri.

A. In my current position as Vice President, Business Planning and Controller, I supervise the Company's financial affairs, including about $1.7 billion of annual non-fuel operations and maintenance ("O&M") expenses and capital expenditures. I direct Ameren Missouri's financial management functions including analysis of monthly/quarterly financial statements, financial forecasting, and budget development and management. I also coordinate the performance management reporting and the business planning process used throughout the Company. I interact with Ameren Missouri's President and senior leadership concerning strategic initiatives, financial forecasts and reports. I also serve as liaison between Ameren Missouri's management and the Ameren Corporation controller function.

Q. Have you previously testified in general rate proceedings before the Missouri Public Service Commission ("MPSC" or "Commission")?

A. Yes. I have testified on numerous occasions before the MPSC, as outlined in Schedule LMB-1 attached to my testimony.

[1] AmerenUE is a d/b/a under which Union Electric Company formerly conducted its business. As noted earlier, Union Electric Company now conducts its business using the d/b/a "Ameren Missouri."

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

A. The purpose of my testimony is to: (a) sponsor the continuation of the Company's fuel adjustment clause ("FAC"), including the minimum filing requirements prescribed by the Commission's FAC rules; (b) address updating the net base energy costs ("NBEC"[2]) that form the base against which changes in the Company's Actual Net Energy Costs ("ANEC") (fuel and purchased power costs net of off-system sales revenues) are tracked in the FAC; and (c) request a mechanism to address the significantly increasing transmission charges being incurred by the Company, primarily arising from Multi Value Projects approved by the Mid Continent Independent System Operator, Inc. ("MISO").

II. FUEL ADJUSTMENT CLAUSE

Q. Is the Company requesting to continue the FAC?

A. Yes. The considerations that supported establishing the FAC in early 2009 still support its continuation now.

Q. When was the Company's FAC first approved?

A. The FAC was first approved in late January 2009 in Case No. ER-2008-0318, and became effective March 1, 2009. While there have been some changes, primarily to add greater details to the FAC tariff, the basic structure and operation of the FAC remain largely the same now as they were at its inception. The FAC rate changes three times per year based upon changes in ANEC during each historical four-month accumulation period, as compared to the NBEC established in each

[2] NBEC consist of the normalized value for the sum of allowable fuel costs (consistent with the term FC in the FAC tariff), plus the cost of purchased power (consistent with the term PP in the FAC tariff), and emissions costs and revenues (consistent with the term E in the FAC tariff), less revenues from off-system sales (consistent with the term OSSR in the FAC tariff).

rate case. For example, a filing to change the FAC rates will be made on or before August 1, 2016 to reflect changes in ANEC as compared to NBEC for the accumulation period of February 2016 to May 2016. Since its inception, 21 such filings have been made. After a rate adjustment filing is made, 95% of the difference between ANEC and NBEC for the subject accumulation period is recovered from (or returned to) customers over an eight-month recovery period. For the filing to be made on or before August 1, 2016, the recovery period will be the eight billing months of October 2016 through May 2017. Interest is applied to the sums recovered or returned. The FAC rates currently in effect were established starting with the June 2016 billing month (which began on May 25, 2016) and reflected a decrease in the FAC rates previously in effect.

Q. Have ANEC increased or decreased since the FAC was continued in the Company's last rate case?

A. ANEC for the 12 months ending with the true-up cutoff date in the last rate case (January 1, 2015) were approximately $756 million and, for the 12 months ending March 31, 2016, were $624 million, a decrease of approximately 17%.

Q. What are the rules for requesting or continuing an FAC?

A. Continuing an FAC is governed by Section 386.266, RSMo, and Commission Rules 4 CSR 240-20.090 and 4 CSR 240-3.161, in particular 3.161(3)(A) through (S) of the latter rule, which prescribe the minimum filing requirements for continuation of an FAC. These minimum filing requirements are provided in the attached Schedule LMB-2.

Q. What are the specific reasons why the Company believes that continuing the FAC is appropriate?

A. There are several reasons why Ameren Missouri's FAC is still appropriate, including: 1) all of the factors the Commission has generally considered in evaluating FACs favor continuation of the FAC; 2) the FAC is reasonably designed to provide the Company a sufficient opportunity to earn a fair return; 3) without an FAC, significant regulatory lag would be present and would prevent the Company from timely reflecting what can be and often are very significant changes in net energy costs in rates, whether those changes are up or down; 4) elimination or any significant modification of the FAC would reflect an inconsistent regulatory policy that would harm the Company's access to needed capital at the lowest reasonable cost; and 5) Ameren Missouri's FAC is important to maintaining the Company's credit quality, primarily because virtually all other electric utilities with whom the credit rating agencies compare Ameren Missouri operate with FACs. In its *Report and Order* in the Company's last electric rate case, issued approximately 14 months ago, the Commission recognized that all of these reasons continued to demonstrate the appropriateness of the Company's FAC.[3]

Q. Please elaborate.

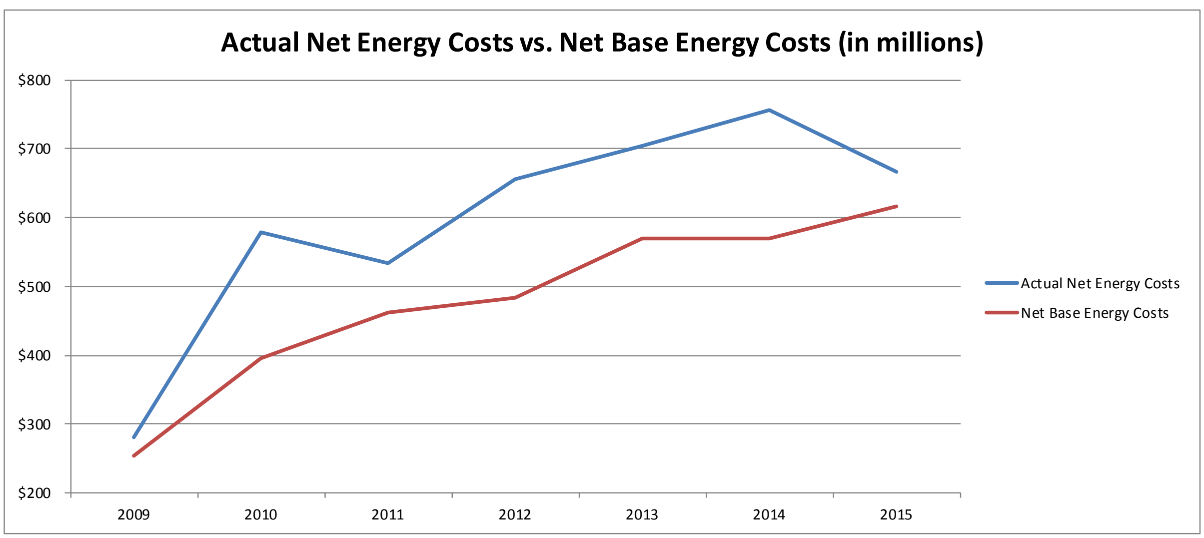
A. The Commission initially approved Ameren Missouri's FAC based in part upon its conclusions about three factors it typically considers when reviewing FAC requests. Specifically, the cost or revenue changes must be:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. Beyond the control of management, where the utility has little influence over experienced revenue or cost levels; and

[3] *Report and Order*, File No. ER-2014-0258, pp. 102-104.

3. Volatile in amount, causing significant swings in income and cash flows if not tracked.

The Company's fuel and purchased power costs are clearly substantial. The Company's fuel and purchased power costs, including transportation (reflected in Factors FC and PP in the FAC tariff), are still the Company's largest O&M expense representing approximately 54% of its total O&M costs. In addition, the Company's ANEC (the sum of Factors FC, P and E less OSSR in the FAC tariff) have risen substantially since the FAC was first established, from approximately $280 million to approximately $670 million as of the end of 2015.[4] Absent the FAC, those changes would have had an extremely material and detrimental impact on Ameren Missouri's financial performance between rate cases. Now that there has been a recent reduction in ANEC as compared to 2014 levels, absent an FAC, customers would not have received the benefit of that reduction.[5] The overall rise in ANEC and the recent reduction through the end of 2015 is depicted in the chart below:



[4] ANEC is even lower for the test year in this case, approximately $580 million.
[5] Customers received 95% of the benefit, since the FAC includes a 95%/5% sharing mechanism.

Q. Can the Company control these costs and revenues?

A. Not significantly, and nothing has changed with respect to the question of control over the past five rate cases (with this being the sixth) in which the Commission approved the FAC and its continuation. The Company still lacks control over the national and international fuel and power markets that dictate what its ANEC will be.[6]

Q. Does volatility and uncertainty continue to exist?

A. Yes, and nothing has changed over the years regarding the continuing volatility of the Company's ANEC, as is clearly shown by the substantial change in the Company's ANEC in the last year and for several years. As the chart above shows, the trend in ANEC has been upward. Yet, even across those years, there have been periods when the ANEC went up, then down, then up again, and most recently, down again, demonstrating the volatility and uncertainty of the Company's fuel and purchased power costs, net of off-system sales. Moreover, the national and international markets that set the prices for fuel and power also continue to be volatile. The volatility we see in the FAC could result in higher charges to customers, but it could result in a reduction of the FAC rates and lower charges to customers as well, as we are now seeing, depending on volumes of fuel burned, prices for power, etc. As the Commission knows, 95% of any such reduction as compared to the NBEC established in this case will be passed through to customers.

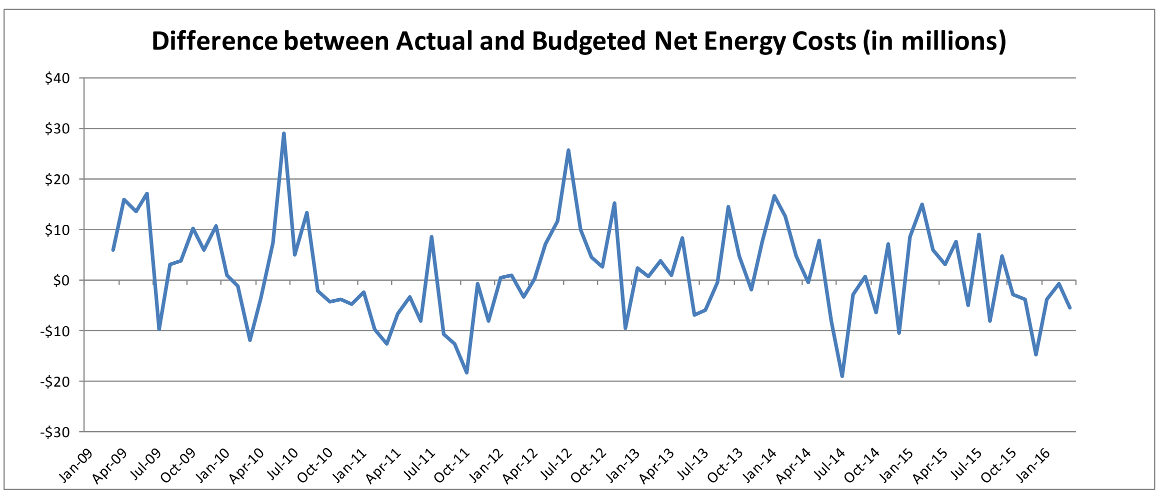
[6] The Commission has recognized this for years: *Report and Order,* Case No. ER-2008-0318, p. 63 ("[M]ost of the costs that comprise [Ameren Missouri's] fuel costs, the costs that would be tracked in a fuel adjustment clause, are dictated by national and international markets, including competing purchases by China and India, far beyond the control of [Ameren Missouri]."); *Report and Order*, File No. ER-2014-0258, p. 103 ("Those fuel and purchased power costs continue to be dictated by national and international markets and thus are outside the control of Ameren Missouri's management.").

Q. The Company hedges some of the exposure to cost changes in the components of ANEC. Does that hedging activity eliminate volatility and uncertainty?

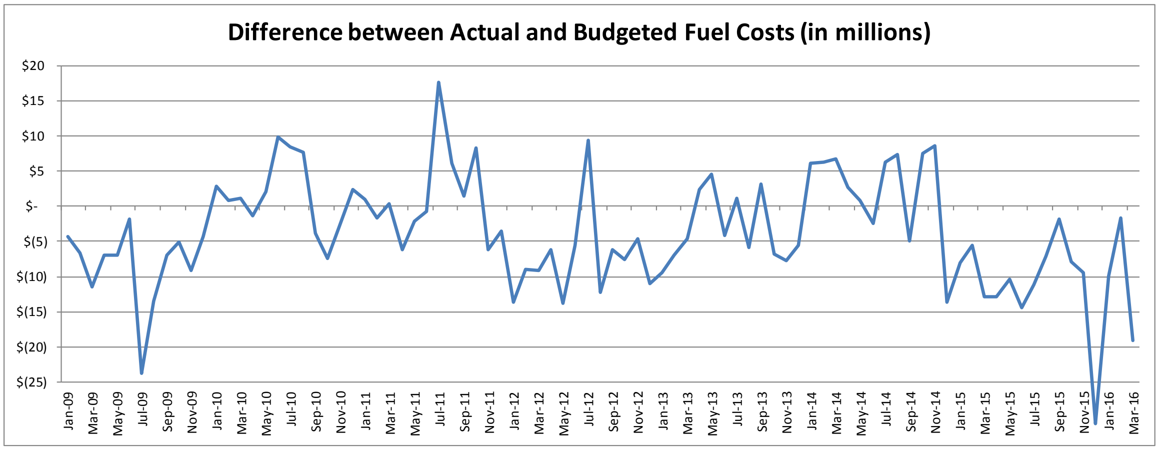
A. No, it does not. While the Company hedges a part of its price exposure, we have very little control over the volumetric components of ANEC. For example, as discussed in Ameren Missouri witness Andrew Meyer's direct testimony, the Company's fuel costs are a function of unit dispatch, which itself is a function of spot fuel and spot energy market prices. Additionally, off-system sales revenues are a function of that same unit dispatch and changes in native load obligations. This can be observed by review of the data and charts in Mr. Meyer's direct testimony.

Q. Are there other indicia of volatility and uncertainty?

A. Yes. The charts below show the variance between what we expected our ANEC to be (per our budget) and what they actually were since the inception of our FAC.



The second chart below shows the same thing for the fuel cost component of ANEC:



One can readily see the uncertainty – both up and down. If these costs were not volatile and uncertain, then we would not see tens of millions of dollars in differences between what we budget and what we actually experience.

In summary, the large fuel and purchased power costs and significant off-system sales revenues that we track in the FAC cannot be controlled by the Company, and are volatile and uncertain.

Q. Does the FAC fully address the lag in time between the incurrence of fuel-related costs and recovery of those costs?

A. Not entirely. As illustrated by Schedule LMB-3, it will take at least 12 months between the time when changes in ANEC occur and when those changes are fully[7] reflected in bills to customers. This is because, unlike in many states, the FAC rules adopted by the Commission require the use of historic, not projected, costs. In addition, the eight-month recovery period included in Ameren Missouri's FAC also contributes to a lag in recovering increased ANEC or returning reduced ANEC.

[7] The FAC does not provide "full" recovery because only 95 percent of the changes in net energy costs are reflected in FAC adjustments.

Q. Earlier, you referenced updated NBEC for this case, indicating that the Company has updated the NBEC used to calculate the Base Factor ("BF")[8] in the FAC tariff to reflect the current level of NBEC. Is that correct?

A. Yes. When rates are re-set in a rate case, the Commission updates all of the costs and revenues that comprise the revenue requirement to reflect more current conditions. NBEC is one of the elements of the cost of service that must be updated, or "rebased;" therefore, as with every other cost in a rate case, the base level of NBEC has been updated to reflect the more current levels of the costs and revenues reflected in the FAC.

In the Company's previous rate case, based on the NBEC in the revenue requirement in that case, the Commission set the BF at 1.796 cents per kilowatt-hour ("kWh") for the summer and 1.729 cents per kWh for the winter. As discussed later in my testimony, we are proposing to implement a third BF in this case, one for the summer (1.679 cents per kWh) and two for two different winter periods (1.739 cents per kWh and 1.587 cents per kWh, respectively). The calculation of the NBEC that underlies these BF values is addressed in detail in the direct testimony of Ameren Missouri witness Laura Moore.

Q. Putting aside the three factors (magnitude/control/volatility-uncertainty) discussed above, are there other important reasons why continuation of the Company's FAC is appropriate and necessary?

A. Yes, there are. Ameren Missouri's FAC remains critical to maintaining the Company's credit quality and keeping the Company's risk profile (with regard to this

[8] Factor BF is determined by dividing the NBEC (which are expressed in dollars) by the billing units to produce a rate.

issue) on par with virtually all of the integrated electric utilities across the country that operate with an FAC (including the three other electric utilities in Missouri). The Commission has previously recognized that "[i]ncreased financial risk results in an increase in a company's cost of borrowing, ultimately increasing costs that will be passed on to ratepayers,"[9] and continued its recognition of the importance of an FAC to the investors (both debt and equity) that provide capital to the Company in its last rate case order.[10]

Q. You mentioned earlier the minimum filing requirements for continuation of the FAC. Has the Company made any material changes to those in this case as compared to the last case?

A. With one exception, no. As we discussed in our last rate case, we have filed very similar information in compliance with the minimum filing requirements in each of the five prior cases where the FAC was established/continued. As we addressed in our last rate case, we believed – and continue to believe – that we have consistently met and, in fact, exceeded the minimum filing requirements. However, to resolve a number of contested FAC-related issues with the Office of the Public Counsel ("OPC") in that case, we entered into a stipulation under which we agreed to "reasonably and in good faith work [with OPC] to agree upon additional descriptions of the costs and revenues included in the FAC, by account, subaccount and activity code." We believe that we and the OPC have lived up to our agreements in this regard, and as a result of that effort, we

[9] *Report and Order*, File No. ER-2010-0036, p. 78.
[10] *Report and Order*, File No. ER-2014-0258, p. 103 ("Ameren Missouri still must compete in the capital markets with other utilities and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness.").

have developed additional descriptions that we have included as part of our minimum filing requirements in this case.[11] Although we are using those additional descriptions in this case, I want to make clear that the subaccounts and activity codes included in the descriptions provide a breakdown of various costs and revenues that is not required by any rule, but instead, have been developed for managerial reporting purposes at Ameren Missouri. We may, and sometimes do, change or eliminate some of these managerial accounting items, which vary from utility to utility.

Q. Has the FAC tariff currently in effect been changed in any material way as filed in this case?

A. We have a few changes, all of which are reflected in an exemplar FAC tariff attached to my testimony as Schedule LMB-4, which shows changes against the FAC tariff currently in effect. First, given changed circumstances relating to Noranda Aluminum, Inc., we have eliminated the adjustment related to load reductions for rate classifications 12(M) and 13(M)(the so-called "N Factor") and made conforming changes elsewhere in the tariff to implement that elimination. Ameren Missouri witness William R. Davis discusses the basis for the elimination in his direct testimony. Second, we have included a listing of the "Charge Types" (which can actually reflect charges or revenues) used by MISO or other centrally-organized markets and under which we have received charges or revenues per the FAC tariff. In the last two cases, this listing had been filed

[11] Consumers Council of Missouri objected to our stipulation with OPC, which rendered our obligation and OPC's obligation to work toward agreeing on these additional descriptions void. However, we believed that working with OPC in an attempt to agree on such additional descriptions was the right thing to do and engaged in efforts with OPC, over many months, to do so. OPC has not indicated that it is in total agreement with all of the descriptions, but after working together we do know that we are in agreement on the vast majority of them. Any remaining differences are quite minor and, we believe, are in the nature of a preference for how a description might be worded as opposed to any material disagreement on the substance of the description.

separately in the docket but referenced in the tariff, but it is administratively more efficient to include the listing in the tariff itself. Third, we have modified the definition of "base factor," or "BF" and added a definition of "NBEC" to better align the tariff language to the terminology that has been used by the Company and other parties in describing these items in prior rate case testimony and other filings. This does not substantively change any FAC calculation or component. Fourth, as I noted earlier, we have added a third BF, so that instead of having just one for summer and one for winter, we are proposing to have one for summer and two for winter.

Q. Please explain further why the Company is proposing to utilize three base factors.

A. The FAC utilizes three accumulation periods of four months each. Changes in costs and revenues that occur within each of those three accumulation periods are compared to the BF that covers them and it is that change that is reflected in the charges under the FAC in a later, eight-month recovery period. The accumulation periods are June through September, October through January and February through May. The last two accumulation periods are generally considered to be "non-summer" periods. However, there are material differences in the base values against which changes in the FAC are measured, as illustrated in the tables below. Those differences mean that the use of a single non-summer BF by itself would result in an under-recovery of changes in net energy costs that occurred in the October through January accumulation period followed by a similar over-recovery of changes that occurred in the February through May accumulation period. Effectively, customers pay too little and then turn around and pay too much, although in the end it all washes out (interest, going both directions, is applied to the under and then over-recoveries).

Status Quo – Single, Winter BF

Accumulation Period (AP)	Load (kWh)	NBEC	Using One Winter BF ($/kWh)	Base (B)	Variance between B and NBEC
Oct. to Jan.	11,367,000,000	$197,659,953	$0.01667	$189,517,175	($8,142,778) (under-billed in Recovery Period for this AP)
Feb. to May	10,192,296,552	$161,789,064	$0.01667	$169,931,842	$8,142,778 (over-billed in Recovery Period for this AP)
Total	21,559,296,552	$359,449,017	$0.01667	$359,449,017	

Implement Two Winter BFs

Accumulation Period (AP)	Load (kWh)	NBEC	Using Two Winter BFs ($/kWh)	Base (B)	Variance between B and NBEC
Oct. to Jan.	11,367,000,000	$197,659,953	$0.01739	$197,659,953	0
Feb. to May	10,192,296,552	$161,789,064	$0.01587	$161,789,064	0
Total	21,559,296,552	$359,449,017		$359,449,017	

To reduce these swings in recoveries, we have simply created a third BF.

III. TRANSMISSION CHARGES AND REVENUES

Q. What is Ameren Missouri's proposal for recovery of transmission charges and revenues?

A. For the reasons given in the Company's last two general rate proceedings, transmission charges and revenues should be tracked in the FAC because they constitute transportation associated with purchased power or off-system sales. The Commission agreed with that proposition in File No. ER-2012-0166. However, by a vote of 3-2, the

Commission reversed course in File No. ER-2014-0258 and concluded that most of Ameren Missouri's transmission charges were not transportation associated with purchased power, and ruled they were ineligible for inclusion in the FAC. We have filed this case on the assumption that the Commission would not reverse course on this issue again. Consequently, we are requesting a tracker for most of those transmission charges and revenues. However, we do believe the Commission reached an incorrect conclusion in that case and if the Commissioners were to reconsider it, we support inclusion of all transmission charges and revenues in the FAC.

Q. You indicated you are requesting a tracker for "most" transmission charges and revenues. Why are you not requesting a tracker for all of them?

A. Because we have filed this case consistent with the Commission's order in our last rate case, which drew a distinction (with which we do not agree) between "true" purchased power and "purchased power" generally. Applying that distinction to the test year figures from this case means that 1.86% of our transmission charges should be included in the FAC, using the Commission's approach. Ameren Missouri witness Mark Peters addresses this calculation in his direct testimony. That leaves the remaining 98.14% of transmission charges and all transmission revenues to be included in the proposed tracker.

Q. Why is a tracker appropriate?

A. While there are no particular statutory (or other) standards that dictate when a tracker is appropriate, in general, the practice has been to consider the magnitude, volatility and level of control over the item proposed to be tracked, as well as whether the item is mandated or otherwise unavoidable (which may in fact simply be a subset of whether it can be controlled). Those factors strongly support a tracker for transmission charges because such charges are large, volatile and uncontrollable and reflect costs that Ameren Missouri must incur to make off-system sales and to acquire the energy we need to re-sell to our load. Moreover, since it is appropriate to track the transmission charges, we believe it also appropriate to match the transmission revenues we receive in the tracker.

Q. Please address these factors as they relate to the transmission charges.

A. The table below clearly illustrates that both the initial value (that which would be included in base rates) and the difference between this base level and projected annual amounts are large and material.

Transmission Costs recorded in Acct. 565
(in millions of $)

** [redacted]	[redacted] **
12 mos ending 12/31/16	** [redacted] **
2017[13]	** [redacted] **
Projected 2018	** [redacted] **
Projected 2019	** [redacted] **
Projected 2020	** [redacted] **

If these charges are not tracked, they would be included in the determination of base rates but at a level that assumes a materially-lower level of costs than will actually be incurred, forcing the Company to absorb them. While in theory, if one assumed that

[12] This number reflects slightly lower transmission charges due to the expectation that Noranda's load loss will continue.

[13] As discussed below, the Company proposes to set the base of the tracker using transmission charges for calendar year 2016 (coinciding with the proposed true-up in this case) adjusted to reflect new transmission service rates in effect for 2017 for MISO Schedule 26A charges since those new rates will be known as of January 1, 2017. As of the filing of this testimony, a projected 2017 rate for Schedule 26A charges is being used and is included as a pro forma adjustment in the revenue requirement addressed in Laura Moore's direct testimony. Because a projected rate for 2017 is being used on for Schedule 26A charges, this number is somewhat different than the number sponsored by Ms. Moore.

the rate-setting process was symmetrical, it is possible that other cost decreases or revenue increases could offset these higher costs. As Ameren Missouri witness Michael Moehn discusses in his testimony, there is no reason to believe that this would be the case. In short, not tracking these costs would be tantamount to forcing the Company to absorb higher costs that the Company is incurring to gain off-system sales and buy power to and from the MISO market, which is the key benefit of being in MISO.

Q. Has this historically been a concern?

A. Yes, it has. As shown by the table below, transmission charges have increased substantially and rapidly over the past few years, driven in particular by transmission charges arising from the construction of Multi Value Projects ("MVP") in MISO.

2012	$17.6 million[14]
2013	$21.1 million
2014	$29.5 million
2015	$38.0 million
2016	**[redacted]**

Q. What has the impact of these rapidly-rising costs had on Ameren Missouri since its last rate case?

A. The level of transmission charges reflected in base rates in our last rate case was $29.5 million. However, from June 1, 2015 through May 31, 2016 (the period since our rates were re-set and transmission charges were removed from the FAC), we

[14] The 2012 and 2013 are net of transmission service charges formerly paid to Entergy or TVA before Entergy became a member of MISO. They were removed so to provide an apples-to-apples comparison to 2014 and 2015, demonstrating that transmission charges (essentially MISO Schedule 26A charges) have **[redacted]** in five years.

have paid $40.2 million in transmission charges, meaning we have absorbed $10.7 million during that one-year period.[15] **[redacted]**

Q. Please address the issue of Ameren Missouri's inability to control these costs.

A. The Commission,[16] as well as its Staff,[17] have recognized that Ameren Missouri does not have any ability to materially manage these costs, absent removing its load from MISO and ceasing making off-system sales to entities outside of MISO. These costs are unavoidable charges assessed as a direct result of Ameren Missouri serving its load requirement in MISO (or as a result of making off-system sales of energy and capacity to entities outside of MISO). The billing determinants are directly related to the amount of load served on these systems, and therefore, they are not a factor within our control.

Q. Please address the volatility of these costs.

A. As indicated in the tables above, these charges are not static, but rapidly rising, with substantial projected increases year-over-year. The Commission has

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[15] These figures are calculated on the 96.5% of transmission charges not included in the FAC.
[16] *Report and Order*, File No. ER-2012-0166, p. 88.
[17] Tr. p. 1290, l. 20 - p. 1291, l. 5, from File No. ER-2012-0166 (Staff auditor Mark Oligschlaeger acknowledging the level of control over these costs is low).

previously found that these charges are volatile.[18] They are also volatile under the plain meaning of the term because they are rapidly rising.[19]

Q. How should such a tracker operate?

A. The tracker should be for both transmission charges and revenues, resulting in the creation of a regulatory asset or liability to reflect the difference between the base level of net costs/revenues included in the revenue requirement in this case and the actual net costs/revenues incurred, excluding from that calculation the 1.86% of transmission charges already being tracked in the FAC.[20] As noted, the Company proposes to set the base using 98.14% of actual transmission charges and all actual transmission revenues for 2016, but for MISO transmission charges under Schedule 26A. The Company is proposing to determine that value using the 2017 MISO Schedule 26A rate which will be known on January 1, 2017. Ameren Missouri would then recommend in its next rate case that this regulatory asset/liability balance should be amortized over five years, and that the unamortized balance should be included in rate base.

With one exception, the tracker should include all transmission service charges appearing in FERC Account 565 and all transmission service revenues appearing in FERC Account 456.1.[21] The one exception arises from ongoing FERC proceedings dealing with past MISO transmission charges and the return on equity on which those charges were based. More specifically, there have been a number of proceedings at the

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[18] The finding was made regarding the key driver of the transmission charges increases we are seeing, those arising from the MISO MVP projects. *Report and Order*, File No. ER-2012-0166, p. 88 ("MISO transmission charges are volatile . . .").
[19] Definition of "volatile," from *Merriam Webster's Collegiate Dictionary* (10th Edition).
[20] The 1.86% figure could change slightly as a result of the true-up in this case.
[21] There are minor amounts (just over $100,000) of MISO Schedule 10 and Schedule 24 revenues that under the applicable accounting are not "transmission service revenues," but which are recorded in Account 456.1 that would not be included in the tracker.

FERC which have resulted, or may result, in a reduction of the return on equity used to set past MISO transmission charges and which, at some point, could result in refunds or credits to Ameren Missouri. To the extent the refunds or credits relate to charges that have not been included in Ameren Missouri's FAC, the refunds or credits would not be included in the tracker since they would relate to prior periods before the tracker was established and would have been paid for entirely by Ameren Missouri.

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 Increase Its Revenues for Electric Service.	)))	**File No. ER-2016-**0179

AFFIDAVIT OF LYNN M. BARNES

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

Lynn M. Barnes, being first duly sworn on her oath, states:

1. My name is Lynn M. Barnes. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Vice President Business Planning & Controller.

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 20 pages and Schedules 1 through 4, 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.

Lynn M. Barnes

Lynn M. Barnes

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

Beckie J. Eaves

Notary Public

My commission expires:

2-21-18

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

Missouri Public Service Commission Testimony

Lynn M. Barnes

File No.	Topic
ER-2014-0258, Ameren Missouri general rate proceeding ER-2012-0166, Ameren Missouri general rate proceeding ER-2011-0028, Ameren Missouri general rate proceeding ER-2010-0036, Ameren Missouri general rate proceeding	Continuation of the Company's fuel adjustment clause.
ER-2008-0318, Ameren Missouri general rate proceeding	Miscellaneous cost of service issues
EO-2010-0255, Ameren Missouri fuel adjustment clause prudence review EO-2012-0074, Ameren Missouri fuel adjustment clause prudence review	Prudence review issues arising from 2009 ice storm impacting Noranda Aluminum, Inc.'s smelting facility.
EU-2012-0027, Ameren Missouri accounting authority order proceeding	Accounting authority order request arising from 2009 ice storm impacting Noranda Aluminum, Inc.'s smelting facility.
EO-2012-0142, Ameren Missouri MEEIA proceeding	Accounting for the throughput disincentive
EO-2014-0095, Kansas City Power & Light Co. MEEIA proceeding	Financial impacts of the alternative Demand-Side Investment Mechanisms proposed in those cases by other parties.
EC-2014-0223, Noranda Aluminum, Inc. at al earnings complaint proceeding	Plant-in-service additions.
EO-2015-0055, Ameren Missouri MEEIA proceeding	Accounting for the throughput disincentive

FAC MINIMUM FILING REQUIREMENTS[1]

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.090(2)(D);

LOCAL PUBLIC HEARING NOTICE

Ameren Missouri has filed tariff sheets with the Missouri Public Service Commission (PSC) that would increase the company's electric service revenues by approximately $206 million. The overall request would raise a typical residential customer's bill by approximately 7.77%, translating to just more than an approximately $8.27 monthly increase. The permanent rate increase request, which is subject to regulatory approval, would take effect no later than May 28, 2017. Ameren Missouri's rate filing also includes a request to continue its fuel adjustment clause in substantially its current form which would continue to allow 95% of increases or decreases in net energy costs to be passed through to customers as a separate line item on customer's bills.

Public comment hearings have been set before the PSC as follows:

[To be determined by the Commission]

If you are unable to attend a live public hearing and wish to make written comments or secure additional information, you may contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone (573) 751-4857, email opcservice@ded.mo.gov or the Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, telephone 1-800-392-4211, email pscinfo@psc.mo.gov. The Commission will also conduct an evidentiary hearing at its offices in Jefferson City during the weeks of __________ through __________, beginning at _____ a.m. The hearings and local public hearings will be held in buildings that meet accessibility standards required by the Americans with Disabilities Act.

If a customer needs additional accommodations to participate in these hearings, please call the Public Service Commission's Hotline at 1-800-392-4211 (voice) or Relay Missouri at 711 prior to the hearing.

(B) An example customer bill showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with 4 CSR 240-20.090(8);

Attached hereto as Attachments A and B are two different examples of customer bills (one in the format used by Ameren Missouri for residential and small general service customers, and one in the billing format used by Ameren Missouri for its other customers), as required by 4 CSR 240-20.091(8).

[1] Each item (A) …. (T) corresponds to the subparagraphs in 4 CSR 240-3.161(3).

(C) Proposed RAM rate schedules;

Attached to the testimony to which this Schedule is attached as Schedule LMB-4 is Rider FAC - Fuel and Purchased Power Adjustment Clause, which is the proposed rate schedule for the fuel adjustment clause proposed by Ameren Missouri, and which shows the changes to the existing Rider FAC as outlined in the testimony.

(D) A general description of the design and intended operation of the proposed RAM;

As discussed in the testimony to which this Schedule is attached, Ameren Missouri is proposing to continue its existing Fuel and Purchased Power Adjustment Clause ("FAC") in substantially its current form. The FAC applies to all rate classes, and would reflect increases or decreases in fuel and purchased power costs, including transportation[2] and emissions costs and revenues, net of off-system sales revenues ("actual net energy costs"), according to the formula expressed in the rate schedule referred to in item (C) above. Historic fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues, would be accumulated during three different Accumulation Periods, as designated in the rate schedule, and then 95% of the change in actual net energy costs would be recovered (if an increase) or credited (if a decrease) using the calculated FAR (as defined in the rate schedule) over three different Recovery Periods (also designated in the rate schedule), each of which cover a period of 8 months. Two of the three changes to the FAR would coincide with the existing seasonal changes in Ameren Missouri's base rates. The tariff includes three seasonal base amounts, known as the "base factor" (factor BF in the tariff), against which changes in actual net energy costs are tracked. The FAR would be applied to customer bills on a per kilowatt-hour ("kWh") basis, as adjusted for voltage level (to take into account varying line losses at different service voltage levels).

The FAR formula includes a factor to accommodate adjustments made as a result of the true-up process or any prudence disallowances occurring as a result of prudence reviews.

(E) A complete explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

Ameren Missouri's continued FAC tariff, which is substantially the same as its existing FAC, continues to be reasonably designed to provide Ameren Missouri with a sufficient opportunity to earn a fair return on equity for several reasons. First, it provides for full and timely recovery of 95% of the changes in Ameren Missouri's actual net energy costs (which, in general terms, consist of fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues), by reflecting increases and decreases in such costs in rates. The 5% of changes not passed through the FAC provide the Company with additional incentives to

[2] Consistent with the Commission's Report and Order in File No. ER-2014-0258, most transmission charges are excluded from the FAC. However, since some transmission charges remain in the FAC this schedule will refer to transportation including associated with purchased power.

manage fuel and purchased power costs, but still provide recovery of 95% of those costs. Full and timely recovery of 95% of those costs is based upon the assumption that an appropriate level of costs and revenues that are tracked in the FAC will be set in base rates based upon these costs in the test year, as updated and trued-up in the rate case, and it also assumes appropriate base rate recovery of other cost of service items. With the FAC, it is more likely that fuel and purchased power costs, which are often times much more significant, volatile, uncertain and much more difficult to control than other utility costs, will be timely and fairly reflected in the rates charged to customers. Examples of factors that can often make these very large but critical costs highly volatile, uncertain and beyond the utility's control include the fact that fuel and purchased power is purchased on national markets which are subject to increasing volatility due to global demand, increased trading activities, world events, financial crises, weather (e.g. hurricanes), abnormally hot or cold weather, or other factors. Second, the FAC assists in addressing the at times increasing and at times decreasing and volatile and uncertain energy costs incurred by the Company in providing service to its customers. Third, a continuation of the FAC continues to keep Ameren Missouri on comparable footing with utilities operating in other states, virtually all of which use similar rate adjustment mechanisms, including on comparable footing with the overwhelming majority of other non-restructured Midwestern states, including the heavily coal-based utilities in these other states. Fourth, the FAC continues to be reasonably designed to provide Ameren Missouri with a sufficient opportunity to earn a fair return on equity because it mitigates the very significant regulatory lag which is prevalent when dealing with such large, uncertain and often volatile costs, by preventing deterioration in (or augmentation of) the utility's financial position (including relative credit standing, which is a key determinant of borrowing costs), and by ensuring recovery of actual net energy costs, which may vary substantially from expected levels.

(F) A complete explanation of how the proposed FAC shall be trued-up to reflect over- or under-collections, or the refundable portion of the proposed IEC shall be trued-up, on at least an annual basis;

The FAC will be trued-up on the first filing date for an adjustment to the FAR that occurs at least two months after the end of each 8-month recovery period. Interest will be calculated on true-up adjustments and included as interest (factor "I") in the calculation of the FAR, as provided for in the FAC tariff.

True-up amounts will reflect the difference between the Fuel and Purchased Power Adjustment ("FPA" as defined in the calculation of the FAR provided for in the FAC tariff) authorized for recovery under the FAC for the subject recovery period and FAR customer revenues actually billed. FAR customer revenues can vary from those expected in calculating the FAR because of variations in the actual kWh sales during a given recovery period versus the estimated KWh sales used to set the FAR in effect during a given recovery period. Additionally, the FAR calculated can vary from the amount originally authorized due to updates of factor "S_{AP}", as defined in Rider FAC. Updates to factor S_{AP} occur as a result of S105 Midcontinent Independent System

Operator, Inc. ("MISO") settlement statements[3]. The MISO settlement statements provide the KWh data for the amount of energy Ameren Missouri purchased to serve its load zone and is multiplied by factor "BF", as defined in Rider FAC, to determine the dollars of net energy costs billed through base rates (factor "B") used to calculate the FPA.

(G) A complete description of how the proposed RAM is compatible with the requirement for prudence reviews;

Ameren Missouri's FAC is compatible with the requirement for prudence reviews for several reasons. Ameren Missouri's FAC is based on actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of actual off-system sales revenues, which simplifies the prudence review. The fuel and purchased power costs included in the FAC are well defined in Rider FAC (the FAC tariff), including specific references to the FERC accounts in which the costs are recorded. Moreover, 4 CSR 240-3.161(5), requires the filing monthly of all the supporting data for the fuel and purchased power costs, revenues, plant generation and related information, all of which can be used as part of the prudence review process. These reports are currently being submitted by Ameren Missouri on a monthly basis. This includes providing monthly fuel burn and generating statistics for each of the generating plants. In addition, 4 CSR 240-3.190 requires submission to the Commission Staff each month of information on system output, hourly generation, purchases and sales, planned outages, forced outages and capacity purchases. All contracts for fuel, transportation and purchased power will also be available for review in connection with the prudence review process. The prudence review could also be used in conjunction with an audit plan, through which appropriate financial data can be sampled from the fuel and fuel transportation invoices that will be available.

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records;

These costs[4] are generally described as follows, and in tables included as Attachment C[5] to this Schedule:

Coal Commodity Costs. This will include costs associated with purchase of coal, as well as British thermal unit ("btu") content adjustments and sulfur content quality adjustments associated with coal contracts. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the coal inventory account and allocation of dollars to

[3] "S105" stand for 105 days after the end of the period covered by the settlement statement.
[4] These cost categories can also include revenues, as provided for in Rider FAC, but are reflected in FERC accounts for costs and, on a net basis, reflect costs.
[5] The descriptions in Attachment C reflect current accounting, including managerial accounting, for these items. The descriptions/accounting may change over time.

each plant will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Coal Transportation Costs. This will include costs associated with transportation of coal, as well as fuel adjustments (e.g., diesel surcharges) associated with transportation contracts and price hedging mechanisms. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as coal is used. A detailed accounting of all additions and adjustments to the coal inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period. Railcar costs are included in this account, and a separate accounting of all railcar costs flowing through inventory will be maintained as well as the allocation of costs to plant inventory accounts.

Oil Costs. This will include costs associated with oil and any price hedging mechanisms. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the oil inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Natural Gas Costs. This will include costs associated with the gas commodity, storage, reservation, transportation, and hedging costs associated with gas-fired plants. A detailed accounting of all additions and adjustments to inventory will be included in a reconciliation, including the calculation of fuel expenses recorded during the accounting period. Also included will be details of all direct costs to expense.

Nuclear Fuel Costs. This will include costs associated with nuclear fuel. These costs are accumulated in inventory accounts under FERC Account 120, and amortized on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Cost of Purchased Power. This will include the cost at the point of receipt by the Company of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy or on-peak energy, ancillary services, etc. In addition, this category will include costs incurred from regional transmission organizations (“RTOs”) for Revenue Sufficiency Guarantee, Losses, deviation charges, revenue neutrality, inadvertent charges, congestion and firm transmission rights but shall exclude MISO administrative costs arising under MISO Schedules 10, 16, 17 and 24, and shall exclude capacity charges under contracts with a term in excess of one (1) year.

Transmission Costs. 1.86% of transmission service charges recorded in FERC account 565 have been included consistent with the methodology approved by the Commission in its Report and Order in File No. ER-2014-0258.

Emissions Allowances. Costs and revenues for SO2 and NOx emissions allowances, including those associated with hedging.

(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records;

These revenues[6] are generally described as follows, and in the tables included as Attachment C[7] to this Schedule:

Off System Sales Revenue. This will include revenues and costs for capacity, energy, ancillary services, make-whole payments, and hedging related to electricity supplied for resale. Ancillary services shall include regulating reserve, energy imbalance, spinning reserve, and supplemental reserve services. Make-whole payments shall include price volatility and revenue sufficiency guarantees.

(J) A complete explanation of any incentive features designed in the proposed RAM and the expected benefit and cost each feature is intended to produce for the electric utility's shareholders and customers;

Ameren Missouri's FAC contains the same FAC-specific incentive feature the Commission included in its existing FAC, and that has also been included in the FACs initially approved for Aquila, Inc. in File No. ER-2007-0004, for The Empire District Electric Company in File No. ER-2008-0093, and that was contained in the continued FAC for Kansas City Power & Light Company – Greater Missouri Operations (formerly Aquila). The FAC is symmetrical. That is, 95% of increases or decreases are passed through the FAC. If Ameren Missouri's net energy costs increase in a given accumulation period, or over time, by only passing through 95% of the changes in net energy costs, customers will benefit by not bearing 5% of those increases and, similarly, if net energy costs decrease in an accumulation period, or over time, shareholders will benefit by being allowed to retain 5% of the decreases. Customers also benefit because of the additional incentive to mitigate net energy cost increases created by the fact that the Company will simply not recover 5% of any increase.

(K) A complete explanation of any rate volatility mitigation features designed in the proposed RAM;

Ameren Missouri's proposed FAC spreads the recovery of the difference between the base energy costs set in the rate proceeding and fuel costs during each Accumulation Period over a full 8-month period. This has a mitigating effect on rate increases or

[6] These revenue categories can also include costs, as provided for in Rider FAC, but are reflected in FERC accounts for revenues and, on a net basis, reflect revenues.
[7] The descriptions in Attachment C reflect current accounting, including managerial accounting, for these items. The descriptions/accounting may change over time.

decreases that will occur as a result of the three periodic FAC adjustments each year. Moreover, as discussed in Item (L) below, Ameren Missouri utilizes a hedging strategy designed to mitigate fuel cost volatility. Moreover, the FAC is seasonally adjusted and contains seasonally differentiated net base fuel costs. This results in tracking higher actual fuel costs against higher base fuel costs (in the Winter) and lower actual fuel costs against lower base fuel costs (in the Summer), both of which tends to mitigate volatility.

(L) A complete explanation of any feature designed into the proposed RAM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed RAM;

In addition to keeping books and records relating to fuel, transportation and purchased power in accordance with Generally Accepted Accounting Principles and the Uniform System of Accounts, Ameren Missouri employs a number of policies, procedures and practices, including the use of internal audits where appropriate, to ensure the prudency of such costs. Described below are relevant policies, procedures and practices.

<u>Fuel and Power Accounting</u>

In order to ensure proper accounting for coal, gas, and nuclear fuel costs, and purchased power costs, including transportation, the following procedures and practices are in place.

Coal. A fuel accounting system called Fuelworx is managed by the coal supply and fuel accounting group. Fuelworx maintains information relating to all contracts, and deliveries scheduled and received against each contract. Fuelworx also records statistical and financial records associated with inventory balances, purchases, and fuel consumption. Fuel accounting enters invoice information into Fuelworx, and matches the invoice amount to contracted amounts for coal, transportation, fuel surcharge, and contracted btu and sulfur adjustments. Any discrepancies are resolved by the fuels contract administration group. Approved invoices are passed electronically to the corporate Accounts Payable system and paid according to contract terms. This system also allocates 8400 and 8800 PRB coal deliveries to each plant on a delivered average cost. This system is critical as it provides all the data related to coal costs for the month-end closing process; and it ensures that all coal commodity, transportation, and quality adjustment costs have been accrued in the proper period. This system is also used to account for oil, limestone and activated carbon costs. All inventory, receivable, and payable accounts associated with coal are balanced on at least a quarterly basis.

Gas. Gas supply executives prepare a month-end estimated gas cost worksheet for Ameren Missouri's generating units. Current month estimates, plus a true-up of prior month actuals versus estimates, are recorded in the current month. All inventory, receivable, and payable accounts associated with gas are balanced on at least a quarterly basis.

Nuclear Fuel. Nuclear fuel expenses and month end balances are calculated in the nuclear fuel accounting system called Surf'n, which is maintained by the nuclear fuel procurement group. All accounts charged in the general ledger are balanced with the nuclear fuel system on at least a quarterly basis.

Purchased Power. For electricity purchased from MISO's markets, Ameren Missouri utilizes the PCI system. This system maintains the detailed MISO charges and statistics pulled directly from the MISO Portal. It gathers Company-provided inputs (e.g. meter data) and MISO-provided data and performs a parallel calculation of expected MISO charges. This recalculation serves as the primary control concerning MISO charges and is performed weekly. On a monthly basis, the data is downloaded from PCI, reviewed, and approved prior to posting in the general ledger. Power purchased outside the MISO market is recorded in the Zainet trade management system, maintained by risk management. These entries are reviewed and approved prior to posting to the general ledger monthly. All receivable and payable accounts associated with power are balanced on at least a quarterly basis.

<u>Fuel and Power Procurement</u>

Fossil (e.g., coal and natural gas): To ensure fuel purchases are prudent, the fuel acquisition for Ameren Missouri's generation is governed by the Ameren Missouri Commodity Risk Management Policy ("Policy"). The rules and guidelines within the Policy, which were approved by Ameren's Risk Management Steering Committee, identify the levels of coal and natural gas for generation that must be acquired and hedged for future periods, identify the various types of allowable commodity transactions, and create extensive management reporting to monitor commodity transactions and price positions. The Policy provides that coal and natural gas be purchased using a risk management strategy that secures the required volume for future periods within maximum and minimum Policy limits while reducing exposure to market volatility. Deviations to the policy are allowed when justified by business conditions but must be approved by the Risk Management Steering Committee. The volumetric risk (securing the necessary quantities of fuel needed for electricity production) and price risk (entering into financial and physical transactions to hedge against price spikes and volatility in the market) for generation fuels are controlled through compliance with the Policy limits. The Policy does not necessarily result in the lowest possible price for fuel, but strikes a balance between price stability and security of supply. In addition to the Policy, there are annual fuel supply planning processes which determine the actual acquisition of fuel for generation needs from various production basins and other parameters of fuel supply including transportation, inventory levels, management of inventory levels through purchases and sales, and logistics with power plants/power traders/generation dispatchers. These processes also encompass the development of competitive or alternative transportation methods between transportation providers to ensure competitive and reliable fuel supply. To ensure competitive fuel supply in the commodity markets, the fuel is procured and hedged through several diverse methods including periodic competitive bids, negotiated purchases, electronic trading, Over-the-Counter ("OTC") transactions, futures market transactions, and spot market transactions. In addition to the Policy and fuel planning processes, the Internal Audit Department conducts routine audits of fuel supply on a three-year cycle for purposes of reporting to senior executives and the Board of Directors. Fuel for generation is purchased by Ameren Missouri personnel, which is staffed with full-time fuel professionals to manage all aspects of fuel supply and operations with a mission of delivering reliable and competitive fuel supply for Ameren Missouri.

Nuclear: To ensure nuclear fuel purchases are prudent, Ameren Missouri follows a number of corporate procurement practices (as outlined below), including the Ameren Missouri Commodity Risk Management Policy approved by Ameren's Risk Management Steering Committee and a Nuclear Division administrative procedure for Nuclear Fuel Contracts. These practices and policies provide very similar controls to those described above relating to procurement of fossil fuels. The foregoing practices, policies and procedures are designed to: i) ensure a safe and reliable supply of nuclear fuel to the Callaway Energy Center, ii) reduce Ameren Missouri's exposure to nuclear fuel price volatility, and iii) mitigate risks related to nuclear fuel. The Policy does not necessarily result in the lowest possible price for nuclear fuel but strikes a balance between price stability and security of supply.

The nuclear fuel cycle consists of the mining of uranium to provide U308, the conversion of the U308 into natural uranium hexafluoride (UF6), the enrichment of the UF6, and finally the conversion of the enriched UF6 into uranium dioxide fuel pellets and the fabrication into nuclear fuel assemblies. Nuclear fuel procurement involves contracting in all of the above processes. Ameren Missouri utilizes long-term contracts to ensure nuclear fuel is available for Callaway requirements. In addition, inventories of nuclear fuel are maintained to enhance security of supply. Ameren Missouri also continually monitors market assessments of nuclear fuel supply and demand, price forecasts, and projections of Callaway fuel requirements. This monitoring is an integral part in the continued review of procurement plans. Price and non-price elements, such as reliability of supply, supplier diversity, quality and quantity must also be balanced. In appropriate instances, nuclear fuel procurements are also made through competitive bidding, with all qualified suppliers solicited (however, depending upon the need, in some instances only 2-3 suppliers may be available). The nuclear fuel supply market is worldwide, and other than the uranium supply component itself, there are limited suppliers for the other components of the nuclear fuel cycle. With the excellent operating performance of existing plants, and as the announced plans for new units become reality and the shutdown reactors in Japan continue to restart, supplies of nuclear fuel are expected to tighten in the coming years.

Nuclear fuel for Callaway generation is purchased by Ameren Missouri personnel, staffed with experienced full-time professionals in nuclear fuel procurement to manage all aspects of nuclear fuel supply and operations and with a mission of providing safe, reliable, and cost effective fuel for Callaway.

Purchased Power: As a vertically integrated utility operating in MISO, Ameren Missouri offers all generation for sale into the market and buys energy to supply all its obligations on a daily basis. The Company reports these amounts consistent with the Uniform System of Accounts, as revised by FERC Orders 668 and 668-A. Should the netted position of these two activities result in the Company being a net purchaser from the MISO, a net charge is shown in FERC Account 555. All MISO-related activity is retrieved from the MISO Portal and validated using PCI software. In addition to these net purchased power costs from RTO settlements, FERC Account 555 includes several other costs related to purchasing similar services or purchases made outside the MISO market. The Company requires all commodity transactional activity be entered into risk management software, called Zainet. The Company perform a control process daily to validate appropriate transactional processing.

(M) A complete explanation of the specific customer class rate design used to design the proposed RAM base amount in permanent rates and any subsequent rate adjustments during the term of the proposed RAM;

The FAC applies the FAR to all of Ameren Missouri's Missouri electric retail customers (*see* Schedule No. 6 - Schedule of Rates for Electric Service). To the extent fuel and purchased power costs are included in base rates the rate design discussed in the direct testimony of Ameren Missouri witness William R. Davis is also applied. With regard to the proposed RAM amount in base rates, a level of $.01679 per kilowatt-hour at the generation level is included in Rider FAC for the summer, $0.01739 per kilowatt-hour for the first winter period and $0.01587 for the second winter period, as filed. Adjustments to the rates for each class will be performed in accordance with the formula reflected in Rider FAC and will be reflective of changes in the factors included in the formula versus the values used to determine the RAM amount in base rates. The adjustments reflect a calculation of the FAR based on test year costs and sales consistent with the factors included in the FAR formula in Rider FAC. Actual customer FAR adjustments will be applied to all retail billings for electric service on a per kilowatt-hour basis, as adjusted for losses based on the customers' service voltage (secondary, primary, large transmission service).

(N) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed RAM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility;

Continuing the RAM will not change Ameren Missouri's business risk. The continuation of a fuel adjustment mechanism (the proposed RAM) would continue to allow Ameren Missouri to pass through to its customers increases and decreases in net energy costs without the need for a costly and time-consuming rate proceeding necessitated by changes in net energy costs. Prior to adoption of FACs for eligible Missouri utilities, the lack of a fuel adjustment mechanism in Missouri had been a major concern to the financial community because net energy costs have been highly volatile.

Because fuel adjustment clauses predominantly are part of the regulation of other U.S. utilities, continuing a fuel adjustment mechanism will keep the business risk of Ameren Missouri more comparable to the risks of other utilities. Without a fuel adjustment mechanism, the business risk of Ameren Missouri would be higher than that of other utilities, all else being equal. However, since most of the electric utilities used in the sample groups of comparable companies in Ameren Missouri's cost of equity studies are able to recover their fuel costs through fuel adjustment clauses, the reduced risk of implementing the proposed RAM in Missouri is already reflected in Ameren Missouri's base cost of equity recommendation (9.9%) in this case. Ameren Missouri witness Robert Hevert addresses the FAC and business risk in his direct testimony.

(O) A description of how responses to subsections (B) through (N) differ from responses to subsections (B) through (N) for the currently approved RAM;

Item (A) includes updated figures. There are no material changes to Items (B), (C), (G), (J), (K) or (T). Item (D) was changed to reflect the three Factor BFs included in the FAC tariff filed in this case and to remove reference to the "N" factor, which was removed from the FAC tariff. Minor updates were made to Items (E) and (F). Items (H) and (I) were augmented with references to a new Attachment C and updated to remove references to water for power to update descriptions of transmission and emission costs and off-system sales. Item (J) was updated to refer to net energy costs and in discussing increases and decreases in net energy costs. Item (L) was updated with a specific discussion of purchased power. Item (M) has includes updated numbers and reflects the three Factor BFs. Item (N) has been changed to refer to net energy costs and to reflect the ROE request in this case. Item (P) has been updated to more specifically described the resources in Attachment D. Item (Q) has been updated to describe the heat rate testing information provided in Attachment E. Item (R) has been updated to reflect more recent IRP information. Item (S) has been updated to reflect developments in environmental regulation.

(P) The supply side and demand side resources that the electric utility expects to use to meet its loads in the next four (4) true-up years, the expected dispatch of those resources, the reasons why these resources are appropriate for dispatch and the heat rates and fuel types for each supply-side resource; in submitting this information, it is recognized that supply and demand-side resources and dispatch may change during the next four (4) true-up years based upon changing circumstances and parties will have the opportunity to comment on this information after it is filed by the electric utility;

Attachment D to this Schedule lists the supply- and demand-side resources expected to meet the Ameren Missouri load requirements, including off-system sales, for the next four years (2016-2019). The data in the table lists the resource name, ownership, primary fuel type, average heat rate for the applicable period, and projected MWh provided by the resource for the four years. These resources are appropriate for inclusion as they are either (1) owned resources historically utilized to serve Ameren Missouri's requirements and expected to do so into the future (as evidenced by their inclusion in Ameren Missouri's integrated resource planning), (2) existing purchased power agreements, (3) demand side programs enacted as part of Ameren Missouri's MEEIA program, or (4) resource additions identified as part of Ameren Missouri's integrated resource planning efforts.

(Q) The results of heat rate tests and/or efficiency tests on all the electric utility's nuclear and non-nuclear steam generators, HRSG, steam turbines and combustion turbines conducted with the previous twenty-four (24) months;

Attachment E to this Schedule contains the results of the heat rate test results for the Company's currently-in-service generating units over the previous 24-months. All of the Company's units have been tested during this period.

(R) Information that shows that the electric utility has in place a long-term resource planning process, important objectives of which are to minimize overall delivered energy costs and provide reliable service;

On October1, 2014, Ameren Missouri made its most recently required triennial Integrated Resource Plan ("IRP") filing (EO-2015-0084), reflecting that important objectives of Ameren Missouri's IRP process are to minimize overall delivered energy costs and provide reliable service. This filing covers Ameren Missouri's long-term resource planning process and consists of multiple volumes. Ameren Missouri's IRP filing reflected analyses for a number of resource options and portfolios, and also examined the Company's capacity position and needs in detail. This information included Ameren Missouri's load forecasts as well as its analysis of available supply-side and demand-side resource options. The end result is a twenty-year resource plan and contingency options. The IRP filing was made in compliance with 4 CSR 240-22.010, et. seq. This very comprehensive Commission rule is designed to insure utilities provide energy services which "…are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies." 4 CSR 240-22.010(2). Ameren Missouri filed its 2016 IRP Annual Update report with the Missouri Public Service Commission (PSC) in March 2016. Ameren Missouri's next triennial IRP filing is due October 1, 2017.

(S) If emissions allowance costs or sales margins are included in the RAM request and not in the electric utility's environmental cost recovery surcharge, a complete explanation of forecasted environmental investments and allowances purchases and sales;

Ameren Missouri established a plan to comply with the new Cross States Air Pollution Rule (CSAPR) that was finalized by USEPA in July 2011. Ameren Missouri's strategy for SO_2 compliance was to continue operation of the wet scrubber system at Sioux Plant coupled with a purchase of ultra-low sulfur coal for the balance of our coal fired units at Labadie, Meramec and Rush Island. No additional capital projects were necessary or planned for SO_2 compliance over the next 5 years. NOx compliance was to be achieved through some capital investment at Labadie Plant for additional over-fire air capacity and through more aggressive NOx tuning on all units across the fleet.

CSAPR had two phases, Phase 1 going into effect January 1, 2012 and Phase 2, the second, more restrictive phase, starting January 2014. Ameren Missouri planned to bank both SO2 and NOx tons during the first phase and use these as necessary to comply with the second phase. As the SO2 bank was projected to be significantly larger than the NOx bank, swapping SO2 allocations for NOx was considered and a small trade was approved by the PSC late in 2011. The CSAPR was stayed by the United States Court of Appeals for the D.C. Circuit in December 2011. The EPA appealed to the United States Supreme Court and the D.C. Circuit ruling was overturned by the United States Supreme Court on April 29, 2014. The case was returned to the D.C. Circuit for further proceedings. The stay of the CSAPR was lifted in late 2014. The EPA with the approval of the D.C. Circuit Court tolled the effective dates of the two phases from 2012 for Phase 1 and 2014 for Phase 2 to 2015 for Phase 1 and 2017 for Phase 2. The CAIR rule expired at the end of 2014. The USEPA removed all remaining CAIR allowances from owner accounts.

Ameren Missouri began operating under the CSAPR on January 1, 2015. Since the CSAPR was a new program there were no previous allowance banks for companies to rely on for compliance in 2015. Ameren Missouri received approval from the Missouri Public Service Commission to manage its allowance bank of SO2 and NOx allowances under the CSAPR. In 2015, Ameren Missouri sold 2,000 annual NOx allowances from its expected surplus allocations. Ameren Missouri believes it will be in compliance with the current Phase 1 and Phase 2 limits of the CSAPR with its installed pollution control equipment and will likely be able to bank both SO2 and NOx allowances in 2016 and beyond.

(T) Any additional information that may have been ordered by the Commission to be provided in the previous general rate proceeding.

The Commission has not ordered any additional information to be provided in connection with a continuation of the FAC.

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Current Charge Detail for Statement 05/19/2016

Electric Charge - Residential	$31.80
Fuel Adjustment Charge	$0.53
Energy Efficiency Investment Charge	-$0.29
St. Louis City Municipal Charge	$1.34
Amount Due	**$33.38**

Electric Service from 04/18/2016 - 05/17/2016 29 Days

	Meter Number	Current Reading	Previous Reading	Current Usage	Reading Type
E	52668324	073984	073709	275 kWh	Actual

AMOUNT DUE	**$33.38**
Due Date:	**06/01/2016**
Account Number	0987654321
Customer Name	JANE DOE
Service Address	123 CENTRAL
Previous Statement	$50.43
Last Payment - 05/11/2016	$50.43

Cash Back For Saving Energy.

Ameren Missouri's BizSavers Energy Efficiency Program offers Standard Fast Track incentives for many types of projects — from lighting and refrigeration upgrades to electric water heating. Visit **AmerenMissouri.com/BizSavers** to check out our new incentives and to stay up-to-date on program developments.

Account Messages

Seasonal Rate Change - Your electric usage for the next four months will be billed at the summer rate which reflects the higher cost of generating electric power in the summer. Look for ways to control your summer bills by visiting AmerenMissouri.com/ActOnEnergy for tips and rebates.

A late payment charge of 1.5% will be added for any unpaid balance on all accounts after the delinquent date.

SPEEDPAY offers residential customers convenient payment options. You can pay your bill using MasterCard, VISA or American Express 24/7 - just call 1.866.268.3729. For recurring payments visit us at AmerenMissouri.com.

Direct Pay Makes Paying Bills Easier. To enroll, go to AmerenMissouri.com or call 1.800.552.7583 to request an enrollment form.

Pure Power lets your home or business support wind power and other forms of renewable energy in Missouri and the Midwest. Learn more at AmerenMissouri.com/purepower.

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> > See reverse for messages

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AMOUNT DUE	Due Date
$33.38	June 01, 2016
Amount After Delinquent Date 06/10/2016	**Account Number**
$33.88	0987654321
Amount Enclosed: $	

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JANE DOE
123 CENTRAL AVE
SAINT LOUIS, MO 63119

AMEREN MISSOURI
PO BOX 88068
CHICAGO IL 60680-1068

0220000 0009876543201 00033880 00033380 00033380

Schedule LMB-2 Attachment A

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Highest Customer Satisfaction with Business Electric Services in the Midwest among Large Utilities.

Ameren MISSOURI

Ameren Missouri received the highest numerical score among large utilities in the Midwest in the J.D. Power 2016 Electric Utility Business Customer Satisfaction Study, based on 21,852 responses from 14 companies measuring experiences and perceptions of consumers surveyed in March and November 2015. Your experiences may vary. Visit jdpower.com.

Address Changes or Corrections

Name ____________________

Address ____________________

City, State, Zip ____________________

Phone Number ____________________

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CREDIT CARD

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866.268.3729

MAIL
STUB & CHECK

IN PERSON
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Schedule LMB-2 Attachment A

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FOCUSED ENERGY. *For life.*

Account Number 1234567890
Customer Name **ABC Co.**
Service Address 123 MAIN ST
SAINT LOUIS, MO 63127

Current Detail for Statement 05/19/2016

Total Electric Charges	$1,441.70
Total Amount Due	**$1,441.70**

AMOUNT DUE	**$1,441.70**
Due Date	**06/01/2016**
Delinquent After	06/10/2016
Amount After Delinquent Date	$1,463.33
Previous Statement	$1,477.13
Total Payments	$1,477.13

Payment Received. Thank You.

Electric Service Details — **Service from 04/18/2016 - 05/17/2016 (29 days)**

Electric Meter Read

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
78802679	04/18 - 05/17	29	Total kWh	Actual	48621.0000	46737.0000	1884.0000	10.0000	18840.0000
78802679	04/18 - 05/17	29	Total kW	Actual	3.8180	0.0000	3.8180	10.0000	38.1800

Usage Summary

Total kWh	18840.0000	Peak kW	38.2000
Total Billing Demand	100.0000	October Winter Base kW	100.0000
Winter Base Demand	38.2000	Base kWh Ratio	1.0000
Base kWh (HUD)	18840.0000	Seasonal kWh (HUD)	0.0000

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» See next page for service details.

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Amount Due	Due Date
$1,441.70	June 01, 2016
Amount After Delinquent Date 06/10/2016	**Account Number**
$1,463.33	1234567890

Amount Enclosed $ ____________________

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ABC Co.
123 MAIN ST
SAINT LOUIS, MO 63129

AMEREN MISSOURI
PO BOX 88068
CHICAGO IL 60680-1068

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Schedule LMB-2 Attachment B

Electric Service Details (Continued)

3M Large General Service

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Seasonal Energy Charge	0.00	kWh	@	$0.03800000	$0.00
Demand Charge	100.00	kW	@	$1.79000000	$179.00
Base Energy Charge / Hours Used	5,730.00	kWh	@	$0.06510000	$373.02
Base Energy Charge / Hours Used	7,640.00	kWh	@	$0.04830000	$369.01
Base Energy Charge / Hours Used	5,470.00	kWh	@	$0.03800000	$207.86
Customer Charge					$92.85
Fuel Adjustment Charge	18,840.00	kWh	@	$0.00191000	$35.98
Energy Efficiency Program Charge	18,840.00	kWh	@	$0.00040000	$7.54
Energy Efficiency Investment Charge	18,840.00	kWh	@	$0.00093800	$17.67
				Total Service Amount	**$1,282.93**

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Missouri State Sales Tax	$1,282.93		@	$0.04225000	$54.20
Missouri Local Sales Tax	$1,282.93		@	$0.02888000	$37.05
St Louis Co Municipal Charge	$1,282.93		@	$0.05263000	$67.52
				Total Tax Related Charges	**$158.77**
				Total Electric Charges	**$1,441.70**

Payments Since Previous Statement

DATE RECEIVED	AMOUNT
April 29, 2016	$1,477.13

Account Messages

A late payment charge of 1.5% will be added for any unpaid balance on all accounts after the delinquent date.

Seasonal Rate Change - Your electric usage for the next four months will be billed at the summer rate which reflects the higher cost of generating electric power in the summer. Look for ways to control your summer bills by visiting AmerenMissouri.com for tips on using energy efficiently.

Address Changes or Corrections

Name ______________________
Address ______________________
City, State, Zip ______________________
Phone Number ______________________

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Schedule LMB-2 Attachment B

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AMOUNT DUE	**$1,441.70**
Due Date	**06/01/2016**
Account Number	1234567890
Service Address	123 MAIN ST

Account Messages (Continued)

Direct Pay Makes Paying Bills Easier. To enroll, go to AmerenMissouri.com or call 1.800.552.7583 to request an enrollment form.

Cash Back For Saving Energy.

Ameren Missouri's BizSavers Energy Efficiency Program offers Standard Fast Track incentives for many types of projects — from lighting and refrigeration upgrades to electric water heating. Visit **AmerenMissouri.com/BizSavers** to check out our new incentives and to stay up-to-date on program developments.

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Schedule LMB-2 Attachment B

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ATTACHMENT C

INCLUSIONS:

For FC = Fuel cost and revenues associated with the Company's generating plants:

FAC Subparagraph #	**Maj**	**Min/RT**	**Activity Code**	**Description**
1 A:	501			Account 501 contains costs/revenues associated with the fuel used in the production of steam for the generation of electricity and also includes cost/revenues generated from the disposal or sale of coal ash.
		001 FB or FI		Costs/revenues for coal used by the coal fired units to generate electricity, such as: - coal commodity costs. - adjustments related to British Thermal Unit (BTU) and Sulfur Dioxide (SO2) quality for each shipment of coal actually received vs. what was contracted to be received. - hedging costs/revenues resulting from forward purchase contracts used to hedge coal purchase costs. - revenues and expenses resulting from fuel portfolio optimization activities which historically have consisted of coal commodity sales. - semi-annual inventory adjustments determined by use of an independent 3rd party to measure each coal pile to true-up the coal burn amounts.
		110 FB or FI		Transportation costs/revenues associated with coal used by the coal fired units to generate electricity, such as: - railroad, truck and barge transportation costs. - diesel surcharges for railroad transportation. - railcar repair and inspection costs. - railcar depreciation, railcar leases. - hedging costs/revenues resulting from forward purchase rail contracts and financial instruments to hedge diesel surcharges. - rail switching charges and demurrage charges associated with rail, truck, and barge transportation. - revenues and expenses resulting from transportation portfolio optimization activities which historically have consisted of such as railcar lease termination fees to allow lower cost leases - semi-annual inventory adjustments determined by use of an independent 3rd party to measure utilizing a global positioning system ("GPS") survey of each coal pile to true-up the coal burn amounts.

		002 FB 012 FI		Costs/revenues for startup oil used by the coal fired units to generate electricity such as oil commodity costs, truck transportation costs, and fuel portfolio optimization activities which historically have consisted of oil commodity sales.
		003 FB 013 FI		Cost/revenues associated with the gas used by the coal fired and natural gas fired units to generate electricity, such as: - gas commodity costs. - pipeline transportation and storage costs. - hedging costs/revenues resulting from forward purchase pipeline transportation contracts. - hedging costs/revenues resulting from forward purchase contracts, call options, and financial instruments used to hedge gas purchases.
		006 All RTs that DO NOT start with L		Coal ash disposal costs and revenues such as physical disposal costs, trucking services, and coal ash sales
B:	502			Account 502 contains cost/revenues associated with the fuel additives used as part of air quality control operations for coal fired generation
		002		Cost of powder activated carbon (including truck transportation costs) used as part of air quality control operations at the coal fired plants
		003		Cost of limestone (including truck transportation costs) used as part of air quality control operations at the coal fired plants
		Unknown at this time		Cost of Urea (including truck transportation costs) used as part of air quality control operations at the coal fired plants
C:	547			Account 547 contains costs/revenues associated with the fuel used in other power generation, including Combustion Turbine Generator (CTG) units.
		002 FB 012 FI		Costs/revenues for oil used in other power generation, which includes both natural gas fired and oil-fired CTGs to generate electricity, including oil commodity costs, truck transportation costs, and fuel portfolio optimization activities which have historically consisted of oil commodity sales.
		003 FB 013 FL		Costs/revenues of gas used in other power generation, which includes CTGs to generate electricity, such as: - gas commodity costs. - pipeline transportation, storage and capacity reserve costs. - fuel losses. - hedging costs/revenues associated with pipeline transportation contracts. - hedging costs/revenues associated with gas purchases. - revenues and expenses resulting from transportation portfolio optimization activities such as pipeline capacity releases and gas commodity sales.

2	518			Account 518 contains cost/revenues associated with the use of nuclear fuel used to generate electricity.
		002		Cost/revenues associated with nuclear fuel used to generate electricity such as: - Nuclear fuel costs (including conversion, enrichment, and fabrication, including safety evaluations and fuel assembly engineering evaluation and analysis, which are necessary to produce the fuel assemblies that are loaded into the reactor.) Monthly nuclear fuel costs recorded to the general ledger as fuel expense reflect an amortization of the total cost of the fuel assemblies to reflect consumption of fuel rods as the plant operates. - storage costs. - hedging costs/revenues associated with nuclear fuel purchases.
		005		Costs associated with the disposal of nuclear fuel waste.

EXCLUSIONS:

For FC = Fuel cost and revenues associated with the Company's generating plants:

FAC Subparagraph #	**Maj**	**Min/RT**	**Activity Code**	**Description**
	501			Costs/revenues associated with coal handling, labor, and materials and supplies inventory.
		000		
		001 Not FB or FI		
		005		
		006 All RTs that start with L		
		020		
		030		
	502	000		Costs/revenues associated with labor, materials and supplies inventory, and SO2 tracker amortization.
		600		
	547	004		Costs/revenues associated with landfill gas commodity.

Notes: Resource Type ("RT") = FB is utilized for managerial reporting and identifies the allocation of fuel costs related to the Company's native load, which are sales to MPSC tariffed customers.

Resource Type ("RT") = FI is utilized for managerial reporting and identifies the allocation of fuel costs related to the Company's remaining sales.

INCLUSIONS:

For E = Costs and revenues for SO_2 and NO_x emissions allowances:

FAC Subparagraph #	**Maj**	**Min/RT**	**Activity Code**	**Description**
	411.8	008		Gain from the disposition of emission allowances.
	411.9	009		Losses on the disposition of emissions allowances.
	509	Unknown at this time		Costs/revenues associated with consumption of emissions allowances such as purchase costs and hedging costs/revenues resulting from forward purchase contracts and financial instruments used to hedge emission allowance purchase costs.

INCLUSIONS:

For PP = Purchased power costs and revenues in Account 555 for:

FAC Subparagraph #	Maj	Min/RT	Activity Code	Description
1 A: i:	555	MIS		Major: 555 Costs directly related to Purchased Power Subaccount (Minor): MISO All MISO costs associated with the following items:
			PPBL	Net energy purchases allocated to native-load sales. Net energy purchases are the netted dollars for sales/purchases made each hour to the RTO settlements, resulting from Ameren Missouri's application of FERC Order 668/668A to the RTO settlements. This is done separately for the DA and RT markets. For managerial reporting purposes, these net energy purchases are then further allocated between interchange sales (PPIS) and native-load sales (PPBL). MISO looks at the generation and load for each hour and bills the net amount.
			PPIS	Net energy purchases allocated to all sales other than native-load sales. Net energy purchases are the netted dollars for sales/purchases made each hour to the RTO settlements, resulting from Ameren Missouri's application of FERC Order 668/668A to the RTO settlements. This is done separately for the DA and RT markets. For managerial reporting purposes, these net energy purchases are then further allocated between interchange sales (PPIS) and native-load sales (PPBL). MISO looks at the generation and load for each hour and bills the net amount.
ii.			MLOS	The component of the location marginal price (LMP) associated with energy losses. LMP is a price for Energy at a specified location in the transmission regions and is comprised of three components: Marginal Energy, Marginal Losses and Marginal Congestion.
iii. a.			MCNG	The component of the locational marginal price (LMP) associated with implicit system congestion. LMP is a price for Energy at a specified location in the transmission regions and is comprised of three components: Marginal Energy, Marginal Losses and Marginal Congestion.
b.			MFTR	Net costs associated with financial transmission rights (FTRs). Net settlement for FTR's, including the initial acquisition cost and periodic settlements. FTRs are a financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges that arise when the Transmission

				System is congested and differences in Marginal Congestion Components of Day-Ahead LMPs between two specific locations such as a generator and a load.
c.			MARR	Net costs associated with auction revenue rights (ARRs). ARRs are entitlements to a share of the revenues generated in the annual FTR Auction.
iv.			DCBL	Capacity purchased for native-load for contracts under 1 year. This capacity purchase may be through a bilateral contract with another party or in an RTO capacity market.
v.			MRSG	Revenue Sufficiency Guarantee. Allocation of costs to load serving entities arising from credits provided to resources committed and scheduled by MISO to ensure minimum recovery of production and operating reserve costs. This allows for recovery of "as offered" price of generation called on for reliability purposes. An "as offered" price typically includes an estimation of startup costs and costs incurred even if the generation does not provide energy. It could be a cost or a reduction to a previously assigned cost.
vi.			MRNU	Revenue Neutrality Uplift Charge. Revenue Neutrality Uplift is the mechanism through which MISO refunds excess revenues collected to Market Participants or collects revenue deficiencies from Market Participants.
vii.			MIDV	Net Inadvertent Distribution. Allocation of costs and revenues to load arising from MISO's resolution of net inadvertent energy. Inadvertent energy is the difference between MISO's scheduled and actual interchange with other balancing authorities.
viii. a.			RFRS	Ancillary Services – Regulating Reserve – Schedule 3 charges. Regulating Reserve charge is for capacity held in reserve by MISO as a frequency responsive resource, for the purpose of automatically and continuously adjusting its output to maintain the supply/demand balance in the MISO balancing authority area in accordance with applicable reliability standards. RFRS revenue for the Company's capacity reserved as a frequency responsive resource is recorded in account 447.
b.			PPIS	Energy purchased for net sales other than native-load related to the energy imbalance (between RT and DA) charges. MISO accounts for energy imbalance through the operation of the Real-Time Energy Market, which charges are included in the net energy amount reported in 1(A)(i) above.
c.			PPBL	Energy purchased for net native load sales related to the energy imbalance (between RT and DA) charges. MISO accounts for energy imbalance through the operation of the Real-Time Energy Market, which charges are included in the net energy amount reported in 1(A)(i) above.
			SPRS	Ancillary Services - Spinning Reserve - Schedule 5 charges.

				Spinning Reserve charge is for the portion of an operating resource capability which is held back (reserved) and able to be converted to energy within ten minutes of being instructed to deploy by MISO. SPRS revenue for the Company's resources offered as spinning reserve is recorded in account 447.
d.			SURS	Ancillary Services - Supplemental Reserve - Schedule 6 charges. Supplemental Reserve charge is for non-synchronized (off-line) resources which can be converted to energy within ten minutes of being instructed to deploy by MISO. SURS revenue for the Company's resources offered as ancillary services resources are recorded in account 447.
ix. a.			PPIS PPBL	MISO demand response resource costs which benefit net sales other than native-load. MISO demand response resource costs which benefit native-load sales.
b.			SC30	Schedule 30 Emergency demand response. Allocation by MISO of charges related to the commitment and dispatch of interruptible demand, behind-the-meter generation and other demand resources that are capable of helping meet the energy balance during NERC Energy Emergency.
B. i.	555	PMJ and SPP		Subaccount (Minor): PJM Interconnection and/or Southern Power Pool (SPP) - Regional Transmission Operators
			PPIS	Net energy purchases allocated to net sales other than native-load
			PPBL	Net energy purchased for native-load. Currently there are no such purchases but there could be if the Company purchased energy in SPP for its load flowing through Kansas City Power & Light Company's system.
			PLOS	The component of locational marginal price (LMP) associated with energy losses.
			PCNG	The component of the locational marginal price (LMP) associated with implicit system congestion.
			PRSG	Balancing Operating Reserve – Equivalent to Revenue Sufficiency Guarantee in MISO
			PFTR	Net costs associated with FTRs and ARRs
			PFRS	Ancillary services - Charges for Synchronized Reserve, Non-Synchronized Reserve, Day-Ahead Scheduling Reserve and Regulation services. Comparable to MISO Spinning Reserve, Supplemental Reserve and Regulating Reserve services.

			PIDV	Net Inadvertent Distribution - Allocation of costs and revenues to load arising from the RTO's resolution of net inadvertent energy. Inadvertent energy is the difference between PJM/SPP's scheduled and actual interchange with other balancing authorities.
ii. a.	555	All minors excluding MIS, PJM or SPP	PPLB	Net energy purchases allocated to native-load sales
			PPIS	Net energy purchases allocated to all sales other than native-load
b.	555	All minors excluding MIS, PJM or SPP	DCIS	Purchased capacity allocated to net sales other than native-load with a duration of one year or less.
			DCBL	Purchased capacity allocated to native-load sales with a duration of one year of less.
C.	555	XXX		Realized losses and costs (including broker commissions and fees) for financial swap transactions to mitigate volatility.

Notes:

DA means the Day-Ahead energy market.

RT means the actual delivered energy (Real Time)

Net off-system sales, interchange sale and net sales other than native load are the same thing.

EXCLUSIONS:

For PP = Purchased power costs and revenues excluded from Account 555:

Maj	Min	Activity Code	Description
555	MIS		Costs associated with MISO schedules specifically excluded from the FAC.
		SC24	Control area recovery
		SC34	Penalty Assessment
		MDEV	RTO uninstructed deviation
		PSIM	Product & Svc implementation
		REEA	Renewable energy/energy assistance

INCLUSIONS:

For PP = Purchased power costs and revenues in Account 565 for:

FAC Subparagraph #	**Maj**	**Min/RT**	**Activity Code**	**Description**
2. A.	565	MIS		Major: 565 Costs related to the Transmission of Electric by Others. Subaccount (Minor): MISO All MISO costs associated with the following items.
i.			TRUN	Purchase of unbundled transmission (Schedule 9 - Network Integration Transmission Service (NITS)) Electric service is traditionally provided by bundling the generation, transmission, and distribution services. Through unbundling, the services can be separated which results in separate pricing and different suppliers or sources for each of the components. NITS represents the transmission service portion, these are covered by our long-term reservation. Ameren Missouri has three MISO NITS reservations - one for its native load in the AMMO pricing zone; one for its native load in the Entergy Arkansas pricing zone and a separate reservation to serve the City of Perryville. Ameren Missouri's designated resources (Ameren Missouri's generation portfolio) is designated to serve these zones.
ii.			SC07	RTO amounts for Schedule 7 - Firm Point to Point Transmission Service Point to Point service uses the transmission system to transmit energy from one point to another. Point to Point can be Firm (service can NOT be interrupted) or Non-Firm (service can be interrupted). This is typically associated with bilateral contracts.
			SC08	RTO amounts for Schedule 8 - Non-Firm Point to Point Transmission Service Point to Point service uses the transmission system to transmit energy from one point to another. Point to Point can be Firm (service can NOT be interrupted) or Non-Firm (service can be interrupted). This is typically associated with bilateral contracts.
iii.			SC01	RTO amounts for Schedule 1 - Scheduling System Control & Dispatch Scheduling and administering the movement of power into, out of, through, or within the MISO Balancing Authority.
iv.			SC02	RTO amounts for Schedule 2 - Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.

v.				MISO Schedule 11 not currently in use. MISO uses Schedule 11 for Wholesale Distribution Service and Pass Through Charges, which are charges that may not be easily identified and associated with a particular schedule.
vi.			SC26	RTO amounts for Schedule 26 - Network Upgrades Transmission Expansion Transmission charge for Network Upgrade Charge from Transmission Expansion Plan under the Regional Expansion Criteria and Benefits (RECB) provisions of the Tariff which is composed of Attachment FF, Attachment GG and Schedule 26. MISO Attachment GG prescribes the revenue requirement calculation for Schedule 26 charges. Historically, the MISO Tariff has included the following types of projects eligible for regional allocation under Attachment GG: > Market Efficiency Projects > Generator Interconnections if they are 345kV > Certain reliability projects approved before 2013 (such as the Company's Lutesville-Heritage line) Cost allocation to pricing zones is performed when project approved based upon project type and voltage. > Market Efficiency - 20% allocated MISO-wide based on load - 80% allocated to Local Resource Zone based on benefits > Reliability projects approved prior to 2013 Tariff change - 345kv facilities – 20% allocated MISO-wide based on load - Remaining facilities allocated sub-regionally based on LODF (Line Outage Distribution Factor) > Generator Interconnections - Per terms of MISO Attachment X - Generally paid by generator
			S26A	RTO amounts for Schedule 26A - Multi Value Projects MVP is a transmission planning and cost allocation project category for projects that qualify based on multiple reliability and/or economic criteria affecting multiple transmission zones. MISO Attachment MM prescribes revenues to be collected under Schedule 26-A. Schedule 26A specifically involves a portfolio of Multi-Value Projects (MVPs) across MISO approved by the MISO Board in December 2011, whereas Schedule 26 is more regional in nature. • Must meet at least one of the following Criteria to be an MVP > Developed through MISO planning process and support energy policy > Provide multiple types of economic value across multiple pricing zones with benefit to cost ratio > 1 > Address at least one: - Projected NERC violation - Economic-based issue

				• MISO-wide allocation across MISO based on load > Attachment MM format is very similar to Attachment GG > Energy market settlement > Currently MISO North load until end of transition period and then 8 year phase-in for MISO South AMMO Zone was approximately 7.5% of MISO North load in 2014
			SC37	RTO amounts for Schedule 37 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for American Transmission System, Inc. (ATSI) Zone (no charges currently) Transmission charge that provides the mechanism for recovering a portion of the MTEP Projects constructed or approved by the MISO Board of Directors (approved prior to ATSI exit from MISO) for construction by ATSI upon ATSI's integration into PJM.
			SC38	RTO amounts for Schedule 38 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for Duke Energy Ohio (DEO) and Duke Kentucky (DEK) (no charges currently) Transmission charge that provides the mechanism for recovering a portion of the MTEP Projects constructed or approved by the MISO Board of Directors (approved prior to DEO/DEK exit from MISO) for construction by DEO/DEK upon DEO/DEK's integration into PJM.
vii.			SC33	RTO amounts for Schedule 33 - Black Start Service Charge to facilitate reliable and complete system restoration following a shut down of the bulk power Transmission System. Blackstart Service enables Transmission Operators to designate specific generation facilities as Blackstart Units whose location and capabilities are required to assist in re-energizing a specific portion of the Transmission System following a system-wide blackout.
viii.			SC41	Charge to Recover Costs of Entergy Storm Securitization Charges from Entergy Operating Companies' Pricing Zones MISO mechanism for collecting storm securitization charges from reservations sinking in Entergy. These transmission charges possess the characteristic of, and are of the nature of, the transmission charges assessed to Ameren Missouri by Entergy to serve Ameren Missouri load using Entergy transmission prior to Entergy joining MISO.
			S42A	Charge to Recover Accrued and Paid Interest Associated with Prepayments From Entergy Operating Companies' Pricing Zones MISO mechanism for collecting accrued and paid interest associated with prepayments for network upgrades to the Entergy Operating Companies. These transmission charges possess the characteristic of, and are of the nature of, the transmission charges assessed to Ameren Missouri by Entergy

				to serve Ameren Missouri load using Entergy transmission prior to Entergy joining MISO.
			S42B	Credit Associated with AFUDC From Entergy Operating Companies' Pricing Zones MISO mechanism for collecting AFUDC credits from network upgrades to the Entergy Operating Companies. These transmission charges possess the characteristic of, and are of the nature of, the transmission charges assessed to Ameren Missouri by Entergy to serve Ameren Missouri load using Entergy transmission prior to Entergy joining MISO.
			SC45	Cost Recovery of NERC Recommendations or Essential Action Transmission charge that provides a mechanism for Transmission Owners who are Registered Entities registered under the NERC Functional Model to recover costs for NERC Recommendations or Essential Action projects eligible under Attachment FF, Attachment GG and Schedule 45.
			SC47	Entergy Operating Companies MISO Transition Cost Recovery MISO mechanism for recovery of the deferred operation and maintenance costs and accrued carrying charges accumulated by the Entergy Operating Companies related to their integration into MISO. This schedule became effective June 1, 2014.
B.	565	All others		Major: 565 Cost of Transmission of Electric by Others Subaccount (Minor): Used to distinguish Non-MISO counterparties to transactions for FERC Form reporting (ex: 565PJM)
i. & ii.			TRUN	Purchase of unbundled transmission (Network Transmission Service) - see definition above. This includes both NITS and point-to-point transmission charges in RTO's other than MISO.
			PITR	PJM or SPP transmission charges
iii.			SSCD	Charges for Scheduling System Control & Dispatch Scheduling and administering the movement of power into, out of, through, or within the Balancing Authority.
iv.			RSVC	Charges for Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.

EXCLUSIONS:

For PP = Purchased power costs and revenues excluded from Account 565. (none)

INCLUSIONS:

For OSSR: Costs and revenues in FERC Account 447:

FAC Subparagraph #		**Maj**	**Subaccount (Minor)**	**Activity Code**	**Description**
1.		447			Major: 447 Revenues related to net off-system sales Subaccount (Minor): refers to various counterparties, Minor XXX is for all hedging activity
			All minors	DERE	Sale of Capacity to various counterparties as identified by the subaccount (Minor) Minor MIS is used for transactions in MISO. Minor PJM is used for transactions in the PJM. Minor SPP is for transactions in the Southern Power Pool. Revenue for MIS, PJM, and SPP minors include capacity sales in the RTO's capacity market and for bilateral contracts. Except where carved out below, all other Minors represent bilateral deals with counterparties. Revenue from the sale of capacity under contract to municipals in included in this activity code.
2.			All minors Except XXX	ENER	Sale of Energy to various counterparties as identified by the subaccount (Minor) Minor MIS is used for transactions in MISO. Minor PJM is used for transactions in the PJM. Minor SPP is for transactions in the Southern Power Pool. Except where carved out below, all other Minors represent bilateral deals with counterparties
				SCON	Sales of Energy to various counterparties for Resale as identified by the subaccount (Minor)
3.	A.	447	MIS	RFRS	Subaccount (Minor) MISO Ancillary Services - Regulating Reserve - Schedule 3 credits Regulating Reserve refers to capacity held in reserve as directed by MISO by a frequency responsive resource owned by Ameren Missouri, for the purpose of automatically and continuously adjusting its output to maintain the supply/demand balance in the MISO balancing authority area in accordance with applicable reliability standards. RFRS costs are recorded in account 555.

				ASMP	Ancillary regulating reserve service balancing charge - Schedule 3 (reduction in revenue) Recapture of ancillary regulating reserve revenues received for Ameren Missouri generating units not deployed.
	B.			ENER	Sale of Energy MISO accounts for energy imbalance through the operation of the Real-Time Energy Market, which charges are included in the net energy amount reported in 2 above
	C.			SPRS	Ancillary Services - Spinning Reserve - Schedule 5 credits Spinning Reserve refers to a portion of an operating resource capability which is held back (reserved) by Ameren Missouri. Spinning reserve must be able to be converted to energy within ten minutes of being instructed by MISO to deploy. SPRS costs are recorded in account 555.
				ASMP	Ancillary spinning reserve service balancing charge - Schedule 5 (reduction in revenue) Recapture of ancillary spinning reserve revenues from received for Ameren Missouri generating units not deployed
	D.			SURS	Ancillary Services - Supplemental Reserve - Schedule 6 credits Supplemental Reserve refers to a non-synchronized (off-line) Ameren Missouri resource which can be converted to energy within ten minutes of being instructed by MISO to deploy. SURS costs are recorded in account 555.
				ASMP	Ancillary supplemental reserve service balancing charge - Schedule 6 (reduction in revenue) Recapture of ancillary supplemental reserve revenues from for Ameren Missouri generating units not deployed
4.	A.			ENER	Sale of Energy Price volatility make-whole payments are credits provided to generators for following MISO dispatch instructions which result in them being out of economic order. These credits are made to make the generator whole against financial loss which would otherwise arise from following these instructions.
	B.			ENER	Sale of Energy Revenue sufficiency guarantee make-whole payments are credits provided to generators to make them whole to their as offered costs, when

					MISO issues a start instruction to a generator when energy prices in the market are not sufficient to cover the generator's as offered costs.
5.		447	XXX	ENER	Hedging costs/revenues resulting from forward purchase contracts, call options, and financial instruments used to hedge power transactions.
			002	ADMN	Broker fees related to power hedging activity
			998	ADMN	Supplier fees associated participation in Illinois Power Agency procurements.

Schedule LMB-2 Attachment D HC

is **HIGHLY CONFIDENTIAL** in its entirety.

Heat Rate Result/Report Index

Unit	Date of Report	Date of Test	Case No.
Callaway	June 2009	June 2009	ER-2010-0036
	June 2010	June 2010	ER-2011-0028
	1-30-2012	1-30-2012	ER-2012-0166
	6-19-2013	6-6-2013	ER-2014-0258
	6-20-2014	June 15-16, 2014	ER-2014-0258
	6-23-2015	May 27-28, 2015	ER-2016-0179
Labadie	11-12-2008	October 2008	ER-2010-0036
	12-30-2008	November 2008	ER-2010-0036
	2-26-2009	December 2008 & January 2009	ER-2010-0036
	3-12-2009	February 2009	ER-2010-0036
	4-9-2009	March 2009	ER-2010-0036
	5-8-2009	April 2009	ER-2010-0036
	6-15-2009	May 2009	ER-2010-0036
	7-10-2009	June 2009	ER-2010-0036
	7-14-2010	June 2010	ER-2011-0028
	1-17-2012	December 2011	ER-2012-0166
	8-13-2012	July 2012	ER-2014-0258
	9-7-2012	August 2012	ER-2014-0258
	10-16-2012	September 2012	ER-2014-0258
	11-2-2012	October 2012	ER-2014-0258
	12-13-2012	November 2012	ER-2014-0258
	1-4-2013	December 2012	ER-2014-0258
	2-27-2013	January 2013	ER-2014-0258
	4-9-2013	February and March 2013	ER-2014-0258
	5-14-2013	April 2013	ER-2014-0258
	6-18-2013	May 2013	ER-2014-0258
	7-5-2013	June 2013	ER-2014-0258
	8-20-2013	July 2013	ER-2014-0258
	9-24-2013	August 2013	ER-2014-0258
	10-30-2013	September 2013	ER-2014-0258
	11-27-2013	October 2013	ER-2014-0258
	12-13-2013	November 2013	ER-2014-0258
	1-8-2014	December 2013	ER-2014-0258
	4-23-2014	January and February 2014	ER-2014-0258
	5-16-2014	March and April 2014	ER-2014-0258
	7-7-2014	May and June 2014	ER-2016-0179
	9-24-2014	July and August 2014	ER-2016-0179
	11-17-2014	September and October 2014	ER-2016-0179
	1-29-2015	November and December 2014	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
	3-6-2015	January and February 2015	ER-2016-0179
	5-22-2015	March and April 2015	ER-2016-0179
	7-31-2015	May and June 2015	ER-2016-0179
	9-21-2015	July and August 2015	ER-2016-0179
	11-24-2015	September and October 2015	ER-2016-0179
	1-22-2016	November and December 2015	ER-2016-0179
	3-18-2016	January and February 2016	ER-2016-0179
	5-23-2016	March and April 2016	ER-2016-0179
Meramec	11-14-2008	October 2008	ER-2010-0036
	3-26-2009	February 2009	ER-2010-0036
	4-8-2009	March 2009	ER-2010-0036
	6-5-2009	May 2009	ER-2010-0036
	7-14-2009	June 2009	ER-2010-0036
	7-27-2010	June 2010	ER-2011-0028
	1-21-2011	December 2011	ER-2012-0166
	8-20-2012	July 2012	ER-2014-0258
	9-8-2012	August 2012	ER-2014-0258
	10-15-2012	September 2012	ER-2014-0258
	11-10-2012	October 2012	ER-2014-0258
	12-11-2012	November 2012	ER-2014-0258
	1-5-2013	December 2012	ER-2014-0258
	2-12-2013	January 2013	ER-2014-0258
	5-3-2013	February and April 2013	ER-2014-0258
	6-19-2013	May 2013	ER-2014-0258
	7-26-2013	June 2013	ER-2014-0258
	8-20-2013	July 2013	ER-2014-0258
	9-24-2013	August 2013	ER-2014-0258
	10-11-2013	September 2013	ER-2014-0258
	1-17-2014	4^{th} Quarter 2013	ER-2014-0258
	2-19-2014	January 2014	ER-2014-0258
	3-14-2014	February 2014	ER-2014-0258
	4-11-2014	March 2014	ER-2014-0258
	5-13-2014	April 2014	ER-2014-0258
	6-16-2014	May 2014	ER-2014-0258
	7-16-2014	June 2014	ER-2016-0179
	8-18-2014	July 2014	ER-2016-0179
	9-16-2014	August 2014	ER-2016-0179
	10-14-2014	September 2014	ER-2016-0179
	11-12-2014	October 2014	ER-2016-0179
	1-16-2015	November and December 2014	ER-2016-0179
	2-13-2015	January 2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
	4-10-2015	February and March 2015	ER-2016-0179
	7-17-2015	April, May, and June 2015	ER-2016-0179
	8-19-2015	July 2015	ER-2016-0179
	9-16-2015	August 2015	ER-2016-0179
	10-22-2015	September 2015	ER-2016-0179
	1-8-2016	4th Quarter 2015	ER-2016-0179
	5-18-2016	January, February, March, April 2016	ER-2016-0179
Rush Island	9-2-2008	August 2008	ER-2010-0036
	11-12-2008	October 2008	ER-2010-0036
	1-12-2009	December 2008	ER-2010-0036
	3-3-2009	February 2009	ER-2010-0036
	4-9-2009	March 2009	ER-2010-0036
	5-18-2009	April 2009	ER-2010-0036
	6-23-2009	May 2009	ER-2010-0036
	7-22-2009	June 2009	ER-2010-0036
	7-25-2010	May 2010	ER-2011-0028
	1-31-2012	December 2011	ER-2012-0166
	8-17-2012	July 2012	ER-2014-0258
	9-10-2012	August 2012	ER-2014-0258
	10-15-2012	September 2012	ER-2014-0258
	11-15-2012	October 2012	ER-2014-0258
	12-10-2012	November 2012	ER-2014-0258
	1-15-2013	December 2012	ER-2014-0258
	3-15-2013	January and February 2013	ER-2014-0258
	4-3-2013	March 2013	ER-2014-0258
	6-19-2013	April and May 2013	ER-2014-0258
	8-21-2013	June and July 2013	ER-2014-0258
	9-6-2013	August 2013	ER-2014-0258
	10-9-2013	September 2013	ER-2014-0258
	11-5-2013	October 2013	ER-2014-0258
	12-17-2013	November 2013	ER-2014-0258
	1-11-2014	December 2013	ER-2014-0258
	3-25-2014	January – February 2014	ER-2014-0258
	4-15-2014	March 2014	ER-2014-0258
	5-19-2014	April 2014	ER-2014-0258
	6-5-2014	May 2014	ER-2014-0258
	7-8-2014	June 2014	ER-2016-0179
	8-8-2014	July 2014	ER-2016-0179
	9-24-2014	August 2014	ER-2016-0179
	10-13-2014	September 2014	ER-2016-0179
	12-30-2014	October and November 2014	ER-2016-0179
	1-21-2015	December 2014	ER-2016-0179
	2-24-2015	January 2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
	3-24-2015	February 2015	ER-2016-0179
	5-13-2015	March and April 2015	ER-2016-0179
	7-24-2015	May and June 2015	ER-2016-0179
	8-22-2015	July 2015	ER-2016-0179
	9-8-2015	August 2015	ER-2016-0179
	10-26-2015	September 2015	ER-2016-0179
	12-14-2015	October and November 2015	ER-2016-0179
	3-28-2016	January and February 2016	ER-2016-0179
	5-16-2016	March and April 2016	ER-2016-0179
Sioux	11-26-2008	October 2008	ER-2010-0036
	1-8-2009	November and December 2008	ER-2010-0036
	2-26-2009	January 2009	ER-2010-0036
	3-19-2009	February 2009	ER-2010-0036
	4-9-2009	March 2009	ER-2010-0036
	5-9-2009	April 2009	ER-2010-0036
	6-24-2009	May 2009	ER-2010-0036
	7-16-2009	June 2009	ER-2010-0036
	7-27-2010	June 2010	ER-2011-0028
	10-26-2011	July, August and September 2011	ER-2012-0166
	9-25-2012	July and August 2012	ER-2014-0258
	11-28-2012	September and October 2012	ER-2014-0258
	1-11-2012 (should be 2013)	November and December 2012	ER-2014-0258
	3-20-2012 (should be 2013)	January and February 2013	ER-2014-0258
	5-31-2013	March and April 2013	ER-2014-0258
	7-31-2013	May and June 2013	ER-2014-0258
	10-10-2013	3rd Quarter 2013	ER-2014-0258
	1-29-2014	4th Quarter 2013	ER-2014-0258
	4-7-2014	1st Quarter 2014	ER-2014-0258
	7-30-2014	2nd Quarter 2014	ER-2016-0179
	12-17-2014	3rd Quarter 2014	ER-2016-0179
	3-4-2015	4th Quarter 2014	ER-2016-0179
	4-20-2015	1st Quarter 2015	ER-2016-0179
	9-22-2015	2nd Quarter 2015	ER-2016-0179
	12-11-2015	3rd Quarter 2015	ER-2016-0179
	1-27-2016	4th Quarter 2015	ER-2016-0179
	5-12-2016	1st Quarter 2016	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
Audrain 1 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-12-2010	ER-2011-0028
	1-17-2012	8-9-2011	ER-2012-0166
	8-26-14	7-17-13	ER-2016-0179
	7-30-2015	7-29-2015	ER-2016-0179
Audrain 2 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-12-2010	ER-2011-0028
	1-17-2012	8-9-2011	ER-2012-0166
	8-26-14	7-17-13	ER-2016-0179
	7-30-2015	7-29-2015	ER-2016-0179
Audrain 3 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-15-2010	ER-2011-0028
	1-17-2012	8-10-2011	ER-2012-0166
	8-26-14	7-17-13	ER-2016-0179
	7-30-2015	7-29-2015	ER-2016-0179
Audrain 4 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-16-2010	ER-2011-0028
	1-17-2012	8-10-2011	ER-2012-0166
	8-26-2014	8-19-2014	ER-2014-0258 (DR 272.2)
	7-30-2015	7-29-2015	ER-2016-0179
Audrain 5 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-13-2010	ER-2011-0028
	1-17-2012	8-11-2011	ER-2012-0166
	8-26-2014	7-24-2014	ER-2014-0258 (DR 272.2)
	8-5-2015	8-4-2015	ER-2016-0179
Audrain 6 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-13-2010	ER-2011-0028
	1-17-2012	8-11-2011	ER-2012-0166
	8-26-2014	7-24-2014	ER-2014-0258 (DR 272.2)
	8-5-2015	8-4-2015	ER-2016-0179
Audrain 7 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-14-2010	ER-2011-0028
	1-17-2012	8-12-2011	ER-2012-0166
	8-26-2014	7-24-2014	ER-2014-0258 (DR 272.2)
	8-26-2015	8-25-2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
Audrain 8 CTG	6-23-2009	6-23-2009	ER-2010-0036
	8-9-2010	7-14-2010	ER-2011-0028
	1-17-2012	8-12-2011	ER-2012-0166
	8-26-2014	7-24-2014	ER-2014-0258 (DR 272.2)
	8-12-2015	8-11-2015	ER-2016-0179
Fairgrounds CTG	8-10-2010	6-24-2010	ER-2011-0028
	1-17-2012	8-2-2011	ER-2012-0166
	10-14-2014	7-19-2013	ER-2014-0258 (DR 272.2)
	8-28-2015	8-26-2015	ER-2016-0179
Goose Creek 1 CTG	6-23-2009	6-23-2009	ER-2010-0036
	12-15-10	8-10-10	ER-2016-0179
	1-17-2012	8-3-2011	ER-2012-0166
	1-14-2014	7-15-2013	ER-2014-0258
	4-27-2015	4-27-2015	ER-2016-0179
Goose Creek 2 CTG	6-25-2009	6-25-2009	ER-2010-0036
	12-15-10	8-10-10	ER-2016-0179
	1-17-2012	8-3-2011	ER-2012-0166
	1-14-2014	7-15-2013	ER-2014-0258
	7-24-2015	7-23-2015	ER-2016-0179
Goose Creek 3 CTG	6-25-2009	6-25-2009	ER-2010-0036
	12-15-10	8-11-10	ER-2016-0179
	1-17-2012	8-3-2011	ER-2012-0166
	1-14-2014	8-7-2013	ER-2014-0258
	7-29-2015	7-28-2015	ER-2016-0179
Goose Creek 4 CTG	6-25-2009	6-25-2009	ER-2010-0036
	12-15-10	8-11-10	ER-2016-0179
	1-17-2012	8-3-2011	ER-2012-0166
	1-14-2014	8-7-2013	ER-2014-0258
	7-29-2015	7-28-2015	ER-2016-0179
Goose Creek 5 CTG	6-25-2009	6-25-2009	ER-2010-0036
	12-15-10	8-12-10	ER-2016-0179
	1-17-2012	8-3-2011	ER-2012-0166
	1-14-2014	7-10-2013	ER-2014-0258
	8-19-2015	8-18-2015	ER-2016-0179
Goose Creek 6 CTG	12-15-10	8-12-10	ER-2016-0179
	1-17-2012	7-20-2011	ER-2012-0166
	1-14-2014	7-10-2013	ER-2014-0258
	4-27-2015	4-27-2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
Howard Bend CTG	1-17-2012	2-15-2011	ER-2012-0166
Retired February, 2015	11-13-2012	8-8-2012	ER-2014-0258
Kinmundy 1 CTG	8-9-2010	8-3-2010	ER-2011-0028
	1-17-2012	6-7-2011	ER-2012-0166
	10-22-2014	8-21-2014	ER-2014-0258 (DR 272.2)
	8-17-2015	8-17-2015	ER-2016-0179
Kinmundy 2 CTG	8-9-2010	8-3-2010	ER-2011-0028
	1-17-2012	6-7-2011	ER-2012-0166
	10-22-2014	8-4-2014	ER-2014-0258 (DR 272.2)
	8-14-2015	8-14-2015	ER-2016-0179
Kirksville CTG	8-9-2010	6-23-2010	ER-2011-0028
	8-9-2010	6-23-2010	ER-2012-0166
	11-13-12	6-21-12	ER-2016-0179
	3-14-2014	7-17-2013	ER-2014-0258
	9-4-2015	9-3-2015	ER-2016-0179
Maryland Heights CTG 1	3-18-2014	8-5-2013	ER-2014-0258
	5-19-2015	5-1-2015	ER-2016-0179
Maryland Heights CTG 2	3-18-2014	8-5-2013	ER-2014-0258
	5-19-2015	5-13-2015	ER-2016-0179
Maryland Heights CTG 3	3-18-2014	8-5-2013	ER-2014-0258
	5-19-2015	5-13-2015	ER-2016-0179
Meramec 1 CTG	2-2-2011	8-31-2010	ER-2012-0166
	11-13-2012	8-16-2012	ER-2014-0258
	1-15-2014	7-15-2013	ER-2014-0258
	8-18-2015	8-18-2015	ER-2016-0179
Meramec 2 CTG	2-2-11	8-9-10	ER-2016-0179
	1-17-2012	6-6-2011	ER-2012-0166
	1-14-2014	7-16-2013	ER-2014-0258
	3-26-2015	3-5-2015	ER-2016-0179
Mexico CTG	8-10-2010	6-21-2010	ER-2011-0028
	1-17-2012	7-18-2011	ER-2012-0166
	10-14-2014	7-17-2013	ER-2014-0258 (DR 272.2)
	7-27-2015	7-24-2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
Moberly CTG	8-10-2010	6-22-2010	ER-2011-0028
	1-17-2012	7-21-2011	ER-2012-0166
	10-14-2014	5-21-2013	ER-2014-0258 (DR 272.2)
	7-24-2015	7-22-2015	ER-2016-0179
Moreau CTG	5-17-2010	8-28-2009	ER-2011-0028
	1-17-2012	8-2-2011	ER-2012-0166
	10-14-2014	7-19-2013	ER-2014-0258 (DR 272.2)
	7-29-2015	7-28-2015	ER-2016-0179
Peno Creek Unit 1 CTG	6-24-2009	6-24-2009	ER-2010-0036
	12-15-10	7-28-10	
	1-17-2012	7-17-2011	ER-2012-0166
	3-14-14	2-11-14	ER-2016-0179
	5-18-2015	3-5-2015	ER-2016-0179
Peno Creek Unit 2 CTG	6-24-2009	6-24-2009	ER-2010-0036
	12-15-10	7-28-10	
	1-17-2012	7-17-2011	ER-2012-0166
	3-14-14	2-11-14	ER-2016-0179
	5-18-2015	3-5-2015	ER-2016-0179
Peno Creek Unit 3 CTG	6-24-2009	6-24-2009	ER-2010-0036
	12-15-10	7-28-10	
	1-17-2012	7-17-2011	ER-2012-0166
	3-14-14	2-11-14	ER-2016-0179
	5-18-2015	3-5-2015	ER-2016-0179
Peno Creek Unit 4 CTG	6-24-2009	6-24-2009	ER-2010-0036
	5-17-2010	4-9-2010	ER-2011-0028
	1-17-2012	7-17-2011	ER-2012-0166
	3-14-14	2-11-14	ER-2016-0179
	5-18-2015	3-5-2015	ER-2016-0179
Pinckneyville 1 CTG	6-24-2009	6-24-2009	ER-2010-0036
	8-9-2010	7-27-2010	ER-2011-0028
	1-17-2012	7-11-2011	ER-2012-0166
	8-27-2014	6-18-2014	ER-2014-0258 (DR 272.2)
	5-19-2015	5-17-2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
Pinckneyville 2 CTG	6-24-2009	6-24-2009	ER-2010-0036
	8-9-2010	7-27-2010	ER-2011-0028
	1-17-2012	7-11-2011	ER-2012-0166
	8-27-2014	6-18-2014	ER-2014-0258 (DR 272.2)
	5-19-2015	5-17-2015	ER-2016-0179
Pinckneyville 3 CTG	6-24-2009	6-24-2009	ER-2010-0036
	8-9-2010	7-28-2010	ER-2011-0028
	1-17-2012	7-11-2011	ER-2012-0166
	8-27-2014	6-18-2014	ER-2014-0258 (DR 272.2)
	5-19-2015	5-17-2015	ER-2016-0179
Pinckneyville 4 CTG	6-24-2009	6-24-2009	ER-2010-0036
	8-9-2010	7-28-2010	ER-2011-0028
	1-17-2012	7-11-2011	ER-2012-0166
	8-27-2014	6-18-2014	ER-2014-0258 (DR 272.2)
	5-19-2015	5-17-2015	ER-2016-0179
Pinckneyville 5 CTG	6-24-2009	6-24-2009	ER-2010-0036
	8-9-2010	7-27-2010	ER-2011-0028
	1-17-2012	7-11-2011	ER-2012-0166
	8-27-2014	4-25-2014	ER-2014-0258 (DR 272.2)
	7-24-2015	7-23-2015	ER-2016-0179
Pinckneyville 6 CTG	6-24-2009	6-24-2009	ER-2010-0036
	8-9-2010	7-27-2010	ER-2011-0028
	1-17-2012	7-11-2011	ER-2012-0166
	8-27-2014	4-30-2014	ER-2014-0258 (DR 272.2)
	8-5-2015	8-4-2015	ER-2016-0179
Pinckneyville 7 CTG	6-24-2009	6-24-2009	ER-2010-0036
	1-17-2012	12-6-2011	ER-2012-0166
	8-27-2014	8-19-2014	ER-2014-0258 (DR 272.2)
	8-13-2015	8-12-2015	ER-2016-0179
Pinckneyville 8 CTG	6-24-2009	6-24-2009	ER-2010-0036
	1-17-2012	3-4-2011	ER-2012-0166
	8-27-2014	4-30-2014	ER-2014-0258 (DR 272.2)
	8-14-2015	8-13-2015	ER-2016-0179

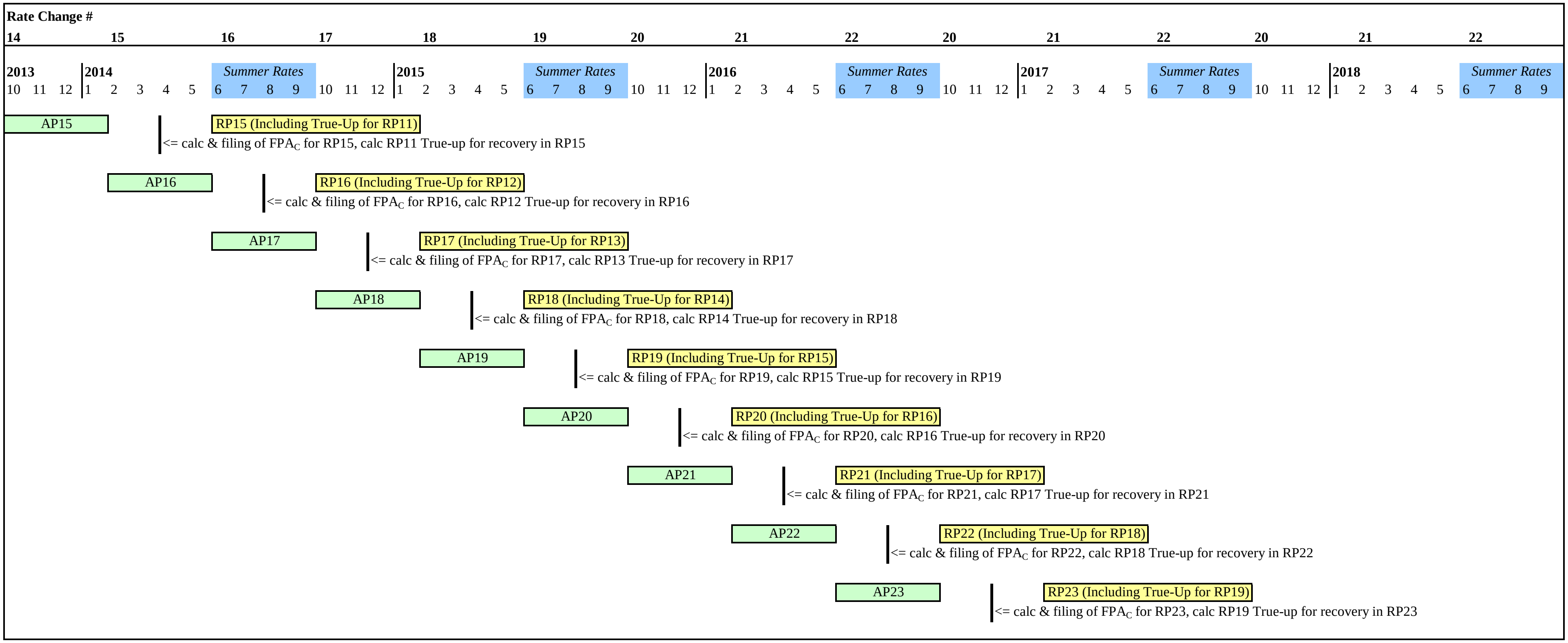
Unit	Date of Report	Date of Test	Case No.
Raccoon Creek 1 CTG	12-15-10	8-16-10	ER-2016-0179
	01-17-2012	6-7-2011	ER-2012-0166
	8-27-2014	8-22-2014	ER-2014-0258 (DR 272.2)
	8-18-2015	8-17-2015	ER-2016-0179
Raccoon Creek 2 CTG	6-25-2009	6-25-2009	ER-2010-0036
	12-15-10	8-16-10	ER-2016-0179
	01-17-2012	6-7-2011	ER-2012-0166
	8-6-2014	8-27-2014	ER-2014-0258 (DR 272.2)
	8-13-2015	8-12-2015	ER-2016-0179
Raccoon Creek 3 CTG	12-15-10	8-17-10	ER-2016-0179
	01-17-2012	6-7-2011	ER-2012-0166
	7-22-2014	8-27-2014	ER-2014-0258 (DR 272.2)
	8-12-2015	8-11-2015	ER-2016-0179
Raccoon Creek 4 CTG	6-25-2009	6-25-2009	ER-2010-0036
	12-15-10	8-17-10	ER-2016-0179
	01-17-2012	6-7-2011	ER-2012-0166
	8-6-2014	8-27-2014	ER-2014-0258 (DR 272.2)
	8-14-2015	8-13-2015	ER-2016-0179
Venice Unit 2 CTG	6-22-2009	6-22-2009	ER-2010-0036
	12-15-10	8-25-10	ER-2016-0179
	01-17-2012	7-17-2011	ER-2012-0166
	3-14-2014	2-10-2014	ER-2014-0258
	5-18-2015	3-5-2015	ER-2016-0179
Venice Unit 3 CTG	6-22-2009	6-22-2009	ER-2010-0036
	12-15-10	8-24-10	ER-2016-0179
	01-17-2012	6-6-2011	ER-2012-0166
	8-27-2014	8-20-2014	ER-2014-0258 (DR 272.2)
	7-20-2015	7-13-2015	ER-2016-0179
Venice Unit 4 CTG	6-22-2009	6-22-2009	ER-2010-0036
	12-15-10	8-24-10	ER-2016-0179
	01-17-2012	6-7-2011	ER-2012-0166
	8-27-2014	8-20-2014	ER-2014-0258 (DR 272.2)
	7-24-2015	7-14-2015	ER-2016-0179

Unit	Date of Report	Date of Test	Case No.
<u>Venice Unit 5 CTG</u>	12-15-10	8-26-10	ER-2016-0179
	01-17-2012	7-19-2011	ER-2012-0166
	10-22-2014	8-22-2014	ER-2014-0258 (DR 272.2)
	8-18-2015	8-17-2015	ER-2016-0179
<u>Viaduct CTG</u>	8-9-2010	8-5-2010	ER-2011-0028
Retired			

Schedule LMB-2 Attachment E HC

Pages 12 – 82 are **HIGHLY CONFIDENTIAL** in their entirety.

Illustration of Ameren Missouri's FAC with Seasonal NBFC/NBEC and Rate Changes



Schedule LMB-3

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

APPLICABILITY

* This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 11(M), 12(M), and 13(M).

* Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC~~)) and Net Base Energy Costs~~)), and the amount of those costs recovered in base rates (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing no later than sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% \pm I \pm P \pm T]/S_{RP}$$

Where:

ANEC = FC + PP + E – OSSR

FC = Fuel costs and revenues associated with the Company's generating plants. These consist of the following:

1. For fossil fuel plants:

   A. the following costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account 501 for: coal commodity, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, oil costs, ash disposal costs and revenues, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

   B. the following costs and revenues reflected in FERC Account 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and powder activated carbon; and

   ~~*~~C. the following costs and revenues reflected in FERC Account 547, excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center. Such costs and revenues include natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

~~*~~2. The following costs and revenues in FERC Account 518 (Nuclear Fuel Expense)for: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

PP = Purchased power costs and revenues and consists of the following:

~~*~~1. The following costs and revenues for purchased power reflected in FERC Account 555, excluding all charges under Midwest Independent Transmission System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and excluding generation capacity charges for contracts with terms in excess of one (1) year. Such costs and revenues include:

~~*Indicates Change.~~

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

A. MISO costs or revenues for MISO’s energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:
   i. Energy;

   ii. Losses;

   ~~*~~iii. Congestion management:
      a. Congestion;
      b. Financial Transmission Rights; and
      c. Auction Revenue Rights;

   iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;

   v. Revenue sufficiency guarantees;

   vi. Revenue neutrality uplift;

   vii. Net inadvertent energy distribution amounts;

   ~~*~~viii. Ancillary Services:
      a. Regulating reserve service (MISO Schedule 3, or its successor);
      b. Energy imbalance service (MISO Schedule 4, or its successor);
      c. Spinning reserve service (MISO Schedule 5, or its successor);and
      d. Supplemental reserve service (MISO Schedule 6, or its successor); and

   ~~*~~ix. Demand response:
      a. Demand response allocation uplift; and
      b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;

   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

~~* Indicates Change.~~

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

*2. ~~Three~~One and ~~one-half~~86/100 percent (~~3.5~~1.86%) of~~ the~~ transmission service costs reflected in FERC Account 565. Such transmission service costs include:

A. MISO costs and revenues associated with:
   i. network transmission service (MISO Schedule 9 or its successor);
   ii. point-to-point transmission service (MISO Schedules 7 and 8 or their successors);
   iii. System control and dispatch, (MISO Schedule 1 or its successor);
   iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);
   v. MISO Schedule 11 or its successor;
   vi. MISO Schedules 26, 26A, 37 and 38 or their successors; and
   vii. MISO Schedule 33;
   **viii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs associated with:
   i. network transmission service;
   ii. point-to-point transmission service;
   iii. System control and dispatch; and
   iv. Reactive supply and voltage control.

*
* Indicates Change. ~~**Indicates Addition.~~

Schedule LMB-4

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

E = Costs and revenues for SO_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

* OSSR = Costs and revenues in FERC Account 447 for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   A. Regulating reserve service (MISO Schedule 3, or its successor);
   B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   C. Spinning reserve service (MISO Schedule 5, or its successor); and
   D. Supplemental reserve service (MISO Schedule 6, or its successor);
4. Make-whole payments, including:
   A. Price volatility; and
   B. Revenue sufficiency guarantee; and
5. Hedging.

~~Adjustment For Reduction of Service Classification 12(M) or 13(M) Billing Determinants:~~

~~*Should the level of monthly billing determinants under Service Classifications 12(M) or 13(M) fall below the level of normalized 12(M) or 13(M) monthly billing determinants as established in Case No. ER-2014-0258, an adjustment to OSSR shall be made in accordance with the following levels:~~

~~a) A reduction of less than 40,000,000 kWh in a given month~~

~~- No adjustment will be made to OSSR.~~

~~*b) A reduction of 40,000,000 kWh or greater in a given month~~
~~- An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction, or (2) off-system sales revenues up to the reduction of 12(M) or 13(M) revenues compared to normalized 12(M) or 13(M) revenues as determined in Case No. ER-2014-0258.~~

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

For purposes of factors FC, E, and OSSR, "hedging" is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities) minus realized gains associated with mitigating volatility in the Company's cost of fuel, off-system sales and emission allowances, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

* Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which MISO or another centrally administered market (e.g., PJM or SPP) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the MISO or another centrally administered market (e.g. PJM or SPP) implement a market settlement charge type or schedule not listed in the FAC Charge Type ~~Exhibit filed with the Commission in File No. ER-2014-0258 on May 6, 2015~~Table included in this Rider (a "new charge type"):

*A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party's right to challenge the inclusion as outlined in E. below;

*B. The Company will make a filing with the Commission giving the Commission notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

~~*~~E. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. A party wishing to challenge the inclusion of a charge type shall include in its filing the reasons why it believes the Company did not show that the new charge type possesses the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

~~**~~F. ~~-~~A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, within 30 days of the

~~*Indicates Change. ** Indicates Addition.~~

FAR DETERMINATION (Cont'd.)

filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = BF x S_{AP}

~~*BF = The Base Factor, which is equal to~~*NBEC = the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR~~) divided by corresponding normalized retail kWh as adjusted for applicable losses.~~). The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case.~~ The BF applicable to June through September calendar months (BF_{SUMMER}) is \$0.01796 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is \$0.01729 per kWh.~~

**BF = NBEC divided by corresponding normalized retail kWh used to determine the revenue requirement in the Company's most recent rate case, as adjusted for applicable losses. The BF applicable to June through September calendar months (BF_{SUMMER}) is \$0.01679 per kWh. The BF applicable to October through January calendar months ($BF_{WINTER-1}$) is \$0.01739 per kWh and applicable to February to May calendar months ($BF_{WINTER-2}$) is \$0.01587.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node~~), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) or 13(M) OSSR adjustment above~~) plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company’s load settled at its MISO CP node (AMMO.UE or successor node).

*Indicates Change.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

T = True-up amount as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

$$FAR = FAR_{RP} + FAR_{(RP-1)}$$

where:

FAR = Fuel Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under– or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*The Initial Rate Component For the Individual Service Classifications shall be determined by multiplying the FAR in accordance with the foregoing by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.~~0575~~0545
Primary Voltage Service (VAF_{PRI})	1.~~0252~~0234
Transmission Voltage Service (VAF_{TRAN})	~~0.9917~~1.0327

Customers served by the Company under Service Classification No. 13(M), Industrial Aluminum Smelter (IAS) Service shall be capped such that their FAR_{IAS}, adjusted for applicable voltage service, does not exceed $0.00200/kWh, with FAR_{IAS} to be determined as follows:

FAR_{IAS} = the lesser of $0.00200/kWh or the Initial Rate Component For Transmission Customers

Where the Initial Rate Component for Transmission Customers is greater than $0.00200/kWh, then a Per kWh FAR Shortfall Adder shall apply to each of the respective Initial Rate Components to be determined as follows:

Per kWh FAR Shortfall Adder = (((Initial Rate Component For Transmission Customers– FAR_{IAS}) x S_{IAS}) / (S_{RP} – S_{RP-IAS}))

Where:

S_{IAS} = Estimated Recovery Period IAS kWh sales at the retail meter

S_{RP-IAS} = Estimated Recovery Period IAS kwh sales at the Company’s MISO CP Node (AMMO.UE or successor node)

The FAR Applicable to the Individual Service Classifications shall be determined as follows:

FAR_{SEC} = Initial Rate Component For Secondary Customers + (Per kWh FAR Shortfall Adder x VAF_{SEC})

FAR_{PRI} = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAF_{PRI})

FAR_{TRAN} = Initial Rate Component For Transmission Customers + (Per kWh FAR Shortfall Adder x VAF_{TRAN})

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in T above. Interest on the true-up adjustment will be included in I above.

*Indicates Change.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

TRUE-UP (Cont'd.)

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

***FAC CHARGE TYPE TABLE**

MISO Energy & Operating Reserve Market Settlement Charge Types and Capacity Market Charges and Credits

DA Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;
DA Financial Bilateral Transaction Congestion Amount;
DA Financial Bilateral Transaction Loss Amount;
DA Loss Rebate on Carve-out GFA;
DA Loss Rebate on Option B GFA;
DA Non-Asset Energy Amount;
DA Ramp Capability Amount;
DA Regulation Amount;
DA Revenue Sufficiency Guarantee Distribution Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;
DA Spinning Reserve Amount;
DA Supplemental Reserve Amount;
DA Virtual Energy Amount;
FTR Annual Transaction Amount;
FTR ARR Revenue Amount;
FTR ARR Stage 2 Distribution;
FTR Full Funding Guarantee Amount;
FTR Guarantee Uplift Amount;
FTR Hourly Allocation Amount;
FTR Infeasible ARR Uplift Amount;
FTR Monthly Allocation Amount;
FTR Monthly Transaction Amount;
FTR Yearly Allocation Amount;
FTR Transaction Amount;
Net Revenue from Voluntary Capacity Auction;
Net Purchase for Voluntary Capacity Auction;

RT Asset Energy Amount;
RT Congestion Rebate on Carve-out GFA;
RT Contingency Reserve Deployment Failure Charge Amount;
RT Demand Response Allocation Uplift Charge;
RT Distribution of Losses Amount;
RT Excessive Energy Amount;
RT Excessive\Deficient Energy Deployment Charge Amount;
RT Financial Bilateral Transaction Congestion Amount;
RT Financial Bilateral Transaction Loss Amount;
RT Loss Rebate on Carve-out GFA;
RT Miscellaneous Amount;
RT Ramp Capability Amount;
Real Time MVP Distribution;
RT Net Inadvertent Distribution Amount;
RT Net Regulation Adjustment Amount;
RT Non-Asset Energy Amount;
RT Non-Excessive Energy Amount;
RT Price Volatility Make Whole Payment;
RT Regulation Amount;
RT Regulation Cost Distribution Amount;
RT Resource Adequacy Auction Amount;
RT Revenue Neutrality Uplift Amount;
RT Revenue Sufficiency Guarantee First Pass Dist Amount;
RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;

MISO Tranmission Service Settlement Schedules

MISO Schedule 1 (System control & dispatch);
MISO Schedule 2 (Reactive supply & voltage control);
MISO Schedule 7 & 8 (point to point transmission service);
MISO Schedule 9 (network transmission service);
MISO Schedule 11 (Wholesale Distribution);
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);
MISO Schedule 33 (Black Start Service);

MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

MISO Charge Types Which Appear On MISO Settlement Statements Represent Administrative Charges And Are Specifically Excluded From The FAC

DA Market Administration Amount;
DA Schedule 24 Allocation Amount;
FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;

RT Market Administration Amount;
RT Schedule 24 Allocation Amount;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

* Indicates Addition.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
***FAC CHARGE TYPE TABLE (Cont'd.)**

PJM Market Settlement Charge Types

Auction Revenue Rights;
Balancing Operating Reserve;
Balancing Operating Reserve for Load Response;
Balancing Operating Reserve for Load Response;
Balancing Spot Market Energy;
Balancing Transmission Congestion;
Balancing Transmission Losses;
Capacity Resource Deficiency;
Capacity Transfer Rights;
Day-ahead Economic Load Response;
Day-Ahead Load Response Charge Allocation;
Day-ahead Operating Reserve;
Day-ahead Operating Reserve for Load Response;
Day-ahead Spot Market Energy;
Day-ahead Transmission Congestion;
Day-ahead Transmission Losses;
Demand Resource and ILR Compliance Penalty;
Emergency Energy;
Emergency Load Response;
Energy Imbalance Service;
Financial Transmission Rights Auction;
Generation Deactivation;
Generation Resource Rating Test Failure;
Inadvertent Interchange;
Incremental Capacity Transfer Rights;
Interruptible Load for Reliability;
Load Reconciliation for Inadvertent Interchange;
Load Reconciliation for Operating Reserve Charge;
Load Reconciliation for Regulation and Frequency Response Service;
Load Reconciliation for Spot Market Energy;
Load Reconciliation for Synchronized Reserve;
Load Reconciliation for Synchronous Condensing;
Load Reconciliation for Transmission Congestion;
Load Reconciliation for Transmission Losses;
Locational Reliability;
Miscellaneous Bilateral;
Non-Unit Specific Capacity Transaction;
Peak Season Maintenance Compliance Penalty;
Peak-Hour Period Availability;
PJM Customer Payment Default;
Planning Period Congestion Uplift;
Planning Period Excess Congestion;
Ramapo Phase Angle Regulators;
Real-time Economic Load Response;
Real-Time Load Response Charge Allocation;
Regulation and Frequency Response Service;
RPM Auction;
Station Power;
Synchronized Reserve;
Synchronous Condensing;
Transmission Congestion;
Transmission Losses;

PJM Transmission Service Charge Types

Black Start Service;
Day-ahead Scheduling Reserve;
Direct Assignment Facilities;
Expansion Cost Recovery;
Firm Point-to-Point Transmission Service;
Internal Firm Point-to-Point Transmission Service;
Internal Non-Firm Point-to-Point Transmission Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service Offset;
Non-Firm Point-to-Point Transmission Service;
Non-Zone Network Integration Transmission Service;
Other Supporting Facilities;
PJM Scheduling, System Control and Dispatch Service Refunds;
PJM Scheduling, System Control and Dispatch Services;
Qualifying Transmission Upgrade Compliance Penalty;
Reactive Services;

* Indicates Addition.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
*FAC CHARGE TYPE TABLE (Cont'd.)

PJM Transmission Service Charge Types (Cont'd.)

Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;
Load Reconciliation for Reactive Services;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service;
Network Integration Transmission Service (exempt);
Reactive Supply and Voltage Control from Generation and Other Sources Service;
Transmission Enhancement;
Transmission Owner Scheduling, System Control and Dispatch Service;
Unscheduled Transmission Service;

PJM Charge Types Which Appear On The Settlement Statements Represent Adminstrative Charges Are Specifically Excluded From The FAC

Annual PJM Building Rent;
Annual PJM Cell Tower;
FERC Annual Charge Recovery;
Load Reconciliation for FERC Annual Charge Recovery;
Load Reconciliation for North American Electric Reliability Corporation (NERC);
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding;
Load Reconciliation for Reliability First Corporation (RFC);
Market Monitoring Unit (MMU) Funding;
Michigan - Ontario Interface Phase Angle Regulators;
North American Electric Reliability Corporation (NERC);
Organization of PJM States, Inc. (OPSI) Funding;
PJM Annual Membership Fee;
PJM Settlement, Inc.;
Reliability First Corporation (RFC);
RTO Start-up Cost Recovery;
Virginia Retail Administrative Fee;

* Indicates Addition.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Calculation of Fuel Adjustment Rate for the Billing Months of ~~June 2016~~XXXXXX 2017 through ~~September 2016~~XXXXX 2017)

*Calculation of Current Fuel Adjustment Rate (FAR):

	Accumulation Period Ending:		~~January 31, 2016~~
1.	Actual Net Energy Cost = (ANEC) (FC+PP+E-OSSR)		$~~198,934,394~~
2.	~~Net Base Energy Cost~~ (B) = (BF x S_{AP})	-	$~~208,577,055~~
2.1	Base Factor (BF)		~~$0.01729/~~$/kWh
2.2	Accumulation Period Sales (S_{AP})		~~12,063,450,248~~ kWh
3.	Total Company Fuel and Purchased Power Difference	=	~~-$9,642,661~~$
3.1	Customer Responsibility	x	95%
4.	Fuel and Purchased Power Amount to be Recovered	=	~~-$9,160,528~~$
4.1	Interest (I)	-	$~~489,598~~
4.2	True-Up Amount (T)	+	$~~8,656,997~~
4.3	Prudence Adjustment Amount (P)	±	$~~0~~
5.	Fuel and Purchased Power Adjustment (FPA)	=	~~-$13,933~~$
6.	Estimated Recovery Period Sales (S_{RP})	÷	~~23,442,797,648~~ kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$0.00000/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	~~-$~~$0.~~00002~~00000/kWh
9.	Fuel Adjustment Rate (FAR)	=	~~-$~~$0.~~00002~~00000/kWh

Initial Rate Component For the Individual Service Classifications

10.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.~~0575~~0545
11.	Initial Rate Component for Secondary Customers		~~-$~~$0.~~00002~~00000/kWh
12.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.~~0252~~0234
13.	Initial Rate Component for Primary Customers		~~-$~~$0.~~00002~~00000/kWh
14.	Transmission Voltage Adjustment Factor (VAF_{TRAN})		~~0.9917~~1.0327
15.	Initial Rate Component for Transmission Customers		~~-$~~$0.~~00002~~00000/kWh

FAR Applicable to the Individual Service Classifications

16.	FAR for Industrial Aluminum Smelter Service (FAR_{IAS}) (The lesser of $0.00200/kWh or Line 15)		~~-$~~$0.~~00002~~00000/kWh
17.	Difference (Line 15 – Line 16)	=	$0.00000/kWh
18.	Estimated Recovery Period Metered Sales for IAS (S_{IAS})		0 kWh
19.	FAR Shortfall Adder (Line 17 x Line 18)		$0
20.	Per kWh FAR Shortfall Adder (Line 19 / (Line 6 – S_{RP-IAS}))	=	$0.00000/kWh
21.	FAR for Secondary Customers (FAR_{SEC}) (Line 11 + (Line 20 x Line 10))	=	~~-$~~$0.~~00002~~00000/kWh
22.	FAR for Primary Customers (FAR_{PRI}) (Line 13 + (Line 20 x Line 12))	=	~~-$~~$0.~~00002~~00000/kWh
23.	FAR for Transmission Customers (FAR_{TRAN}) (Line 15 + (Line 20 x Line 14))	=	~~-$~~$0.~~00002~~00000/kWh

*Indicates Change.