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Witness:	Marci L. Althoff
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2019-0335
Date Testimony Prepared:	July 3, 2019

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

DIRECT TESTIMONY

OF

MARCI L. ALTHOFF

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
July 2019

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DIRECT TESTIMONY

OF

MARCI L. ALTHOFF

FILE NO. ER-2019-0335

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Marci L. Althoff. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

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

A. I am employed by Ameren Services Company ("Ameren Services") as Manager, Finance Transformation. Ameren Services provides various corporate support services to Union Electric Company d/b/a Ameren Missouri ("Company" or "Ameren Missouri"), including settlement and accounting related to fuel, purchased power, and off-system sales.

Q. Please describe your educational and professional background.

A. I have a Master of Accountancy and Bachelor of Science degree in Accountancy from the University of Missouri, Columbia, Missouri. I am also a Certified Public Accountant in Missouri. I began my career with Ernst & Young LLP in their Assurance Services practice before joining Ameren Services Company as a Financial Specialist in Fuel and Gas Accounting in 2010. I was promoted to Supervisor, Fuel and Gas Accounting in 2012 where my responsibilities included review and approval of Ameren Missouri's fuel-related journal entries and the fuel adjustment clause ("FAC") entries and filings. In 2015, I was promoted to Manager, Power and Fuels Accounting and began sponsoring testimony for the FAC rate and true-up filings in 2017. In March 2019, I accepted a new role as Manager, Finance Transformation, but have retained responsibility for FAC-related filings. In addition to those FAC-related responsibilities, in my new role I am a leader on the Ameren Services team working to modernize our finance organizational structures, systems, and end-to-end processes with the goal of reducing cost to the ultimate benefit of customers.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to: (a) sponsor the continuation of Ameren Missouri's FAC, including the minimum filing requirements prescribed by the Commission’s FAC rules; and (b) address updating the net base energy costs ("B" in the FAC tariff sheets and sometimes referred to as "NBEC") that form the base against which changes in the Company’s Actual Net Energy Costs ("ANEC") are tracked in the FAC.

III. <u>FUEL ADJUSTMENT CLAUSE</u>

Q. Is the Company requesting to continue the FAC?

A. Yes. The considerations that supported the Commission's approval of the FAC initially and the Commission's continuation of it in the past five rate cases support its continuation now.

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

A. The FAC was first approved in late January 2009 in File No. ER-2008-0318, and became effective March 1, 2009. While there have been some changes, primarily to add more details to the FAC tariff sheets, the basic structure and operation of the FAC remains largely the same now as it was 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 rate case. For example, a filing to change the FAC rates will be made on or before August 1, 2019 to reflect changes in ANEC as compared to NBEC for the accumulation period of February 2019 to May 2019. Since the FAC's inception, 30 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, 2019, the recovery period will be the eight billing months of October 2019 through May 2020. Interest is applied to the sums recovered or returned. The FAC rates currently in effect were established starting with the June 2019 billing month and reflect a decrease in the FAC rates previously in effect because of decreases in ANEC as compared to the base established in the last general rate proceeding.

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

A. ANEC have decreased. ANEC for the 12 months ending with the true-up cut-off date in the last rate case (December 31, 2016) were approximately $610 million and, for the 12 months ending December 31, 2018, were approximately $517 million, a decrease of approximately 15%.

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

A. Continuing an FAC is governed by Section 386.266, RSMo, and Commission Rule 4 CSR 240-20.090, in particular 20.090(2)(A), which prescribes the minimum filing requirements for continuation of an FAC. These minimum filing requirements are provided in the attached Schedule MLA-D1.

Q. What are the specific reasons why 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, and those changes can impact the Company's ability to earn a fair return; 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.

While the Company's last electric general rate proceeding was resolved by a comprehensive settlement, in its *Report and Order* in the Company's last fully litigated electric rate case, the Commission recognized that all of these reasons continued to demonstrate the appropriateness of the Company's FAC.[1] With only one substantive change, which I will address later in my testimony, the Company's FAC was also continued in the last general rate proceeding by agreement of the settling parties which was approved by the Commission.

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

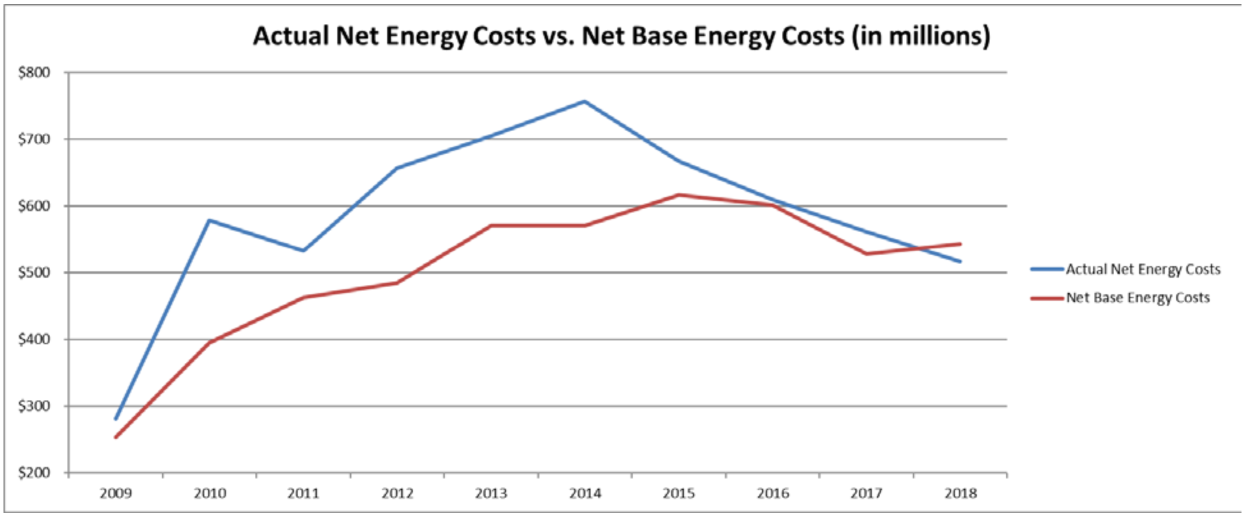
Q. Please elaborate.

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, these factors hold that the changes in costs or revenues that would be included in the FAC 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. 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 current FAC tariff), are still the Company's largest operations and maintenance ("O&M") expense representing approximately 48% of its total O&M costs in 2018. In addition, the Company's ANEC (the sum of Factors FC, PP, E, and R less OSSR in the FAC tariff) have changed substantially since the FAC was first established, from a low of approximately $280 million in 2009 to a high of approximately $756 million in 2014 followed by a reduction to approximately $517 million as of the end of 2018. Absent the FAC, those changes would have had an extremely material and detrimental impact on Ameren Missouri's financial performance between rate cases and when decreases have occurred those decreases would not have been timely passed through to customers.[2] The changes in ANEC through the end of 2018 are depicted in the chart below:

[2] 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.[3]

Q. Do 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 changes in the Company's ANEC over the past several years. As the chart above shows, ANEC has increased since the FAC was first established. Across these 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

[3] 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.").

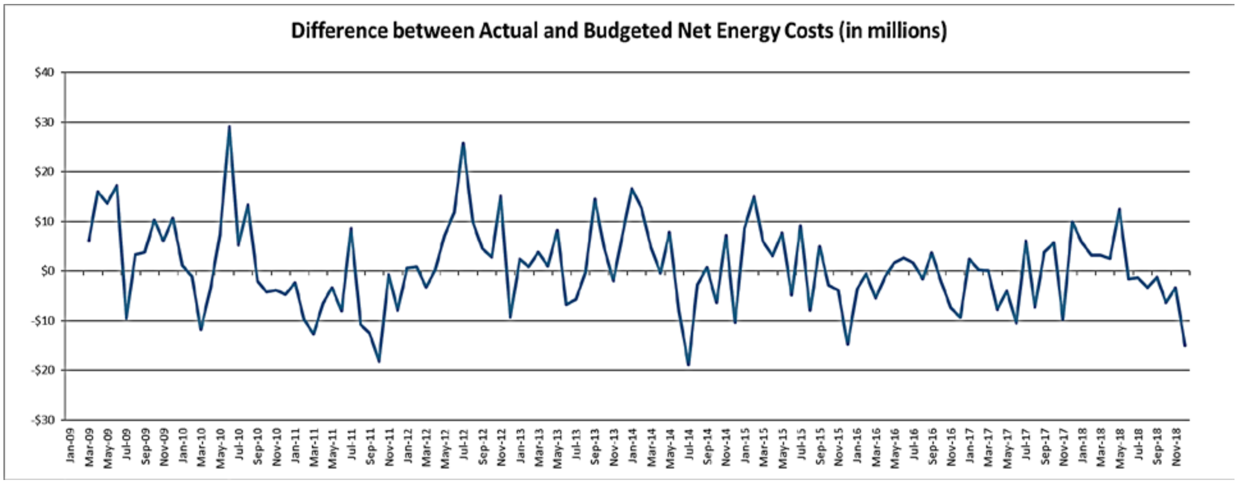
costs net of off-system sales, including transportation. Moreover, the national and international markets that set the prices for fuel and power also continue to be volatile. The volatility we see in the FAC could result in higher charges to customers, but it could result in a reduction of the FAC rates 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. The volatility and uncertainty of FAC components is discussed in greater detail in the direct testimony of Ameren Missouri witness Andrew Meyer.

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

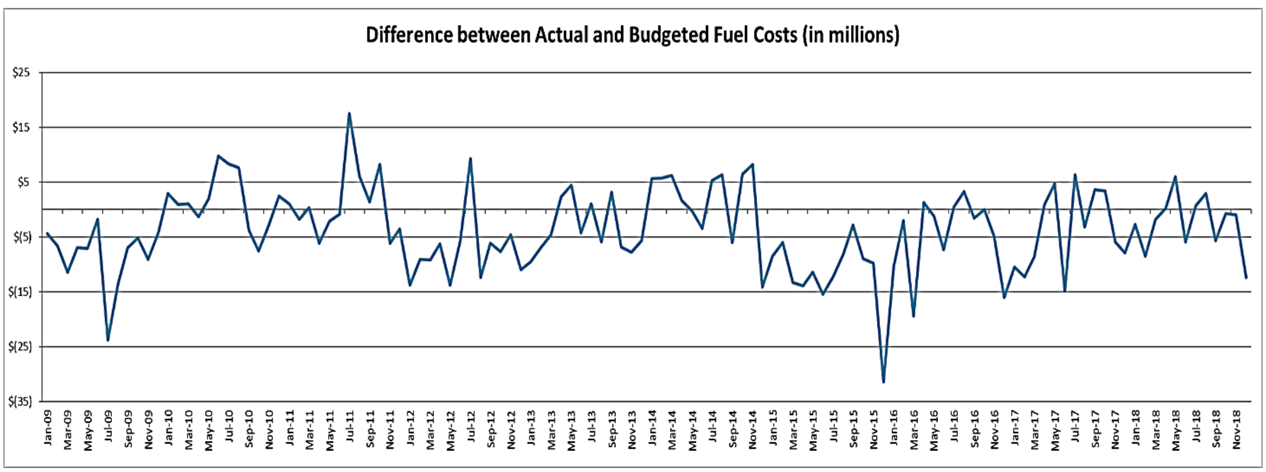
A. No, it does not. While the Company hedges a part of its price exposure, we have very little control over the volumetric components of ANEC. For example, as discussed in Mr. Meyer's direct testimony, the Company's fuel costs are a function of unit dispatch, which itself is a function of spot fuel and 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 the FAC.



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



One can readily see the volatility – 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 MLA-D2, it will take at least 12 months between the time when changes in ANEC occur and when those changes are fully[4] reflected in bills to customers. This is because, unlike the rules 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.

Q. Earlier, you referenced updated B (net base energy costs, sometimes referred to as NBEC) for this case, indicating that the Company has updated the B used to calculate the Base Factor ("BF")[5] in the FAC tariff to reflect the current level of B. 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. B 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 B has been updated to reflect more current levels of the costs and revenues reflected in the FAC.

In the Company's previous rate case, the Commission set the BF at 1.565 cents per kilowatt-hour ("kWh") for the summer and 1.536 cents per kWh for the winter, based on the NBEC in the revenue requirement in that case. We are proposing to update the BF to 1.266 cents per kWh for the summer and 1.208 cents per kWh for the winter. The

[4] The FAC does not provide "full" recovery because only 95 percent of the changes in net energy costs are reflected in FAC adjustments.
[5] Factor BF is determined by dividing the B (which is expressed in dollars) by the billing units to produce a rate.

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 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,"[6] 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.[7]

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. We have updated our minimum filing requirements for continuation of the FAC to meet the requirements set forth in Commission Rule 4 CSR 240-20.090, in

[6] *Report and Order*, File No. ER-2010-0036, p. 78.
[7] *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.").

particular 20.090(2)(A), which includes addressing as needed changes made to these requirements by the Commission's 2018 FAC rulemaking.

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

A. We are recommending some changes, all of which are reflected in an exemplar FAC tariff attached to my testimony as Schedule MLA-D3, which shows changes tracked against the FAC tariff currently in effect. None of the changes fundamentally change the components in the FAC as compared to what those components have generally been since the FAC was first approved in 2009. However, as I previously mentioned, we are proposing one substantive change to the tariff.

Q. What is the substantive change to the tariff that you are proposing?

A. We are proposing an amendment to the definition of FC to add back ash disposal costs and revenues and fuel additives. These costs and revenues have been included in Ameren Missouri's FAC since its inception but as a concession to the Office of the Public Counsel ("OPC") to obtain a comprehensive settlement of Ameren Missouri's last general rate proceeding, we agreed to exclude them from the FAC at that time. However, it was and remains our position that these are legitimate fuel costs and revenues that should be added back to the FAC. The Commission has been called upon once to decide the question of whether these costs and revenues should be included in the FAC, and its decision was that these are legitimate fuel costs and revenues that should remain in the FAC. This decision was issued in response to OPC's argument to exclude several different components of fuel costs based on its opinion of what the "purest" definition of fuel should be,[8] an argument the Commission rejected. The debate about this occurred in general rate cases for Kansas City Power & Light Company and KCPL Greater Missouri Operations Company (collectively, "KCPL") (File Nos. ER-2016-0285 and ER-2016-0286) occurring largely concurrently with Ameren Missouri's last general rate case. Both KCPL and the Staff took the position that the costs and revenues included in KCPL's FAC should remain as they were and the Commission agreed, the result being that these ash disposal costs and revenues remain in KCPL's FAC as they have always been. Such costs and revenues are also included in The Empire District Electric Company's FAC.

Q. What other changes to the FAC tariff are you proposing?

A. The second change we are recommending to the FAC tariff consists of amendments to the PP (purchased power) and OSSR (off-system sales) definitions to exclude costs and revenues associated with the Renewable Choice Program so that these costs and revenues are properly attributed to the correct customers and neither Ameren Missouri retail customers nor Ameren Missouri benefits from or is harmed by the Renewable Choice Program. Such a change was contemplated by the stipulation approved by the Commission in the Renewable Choice docket.

Third, we have added a calculation to allow for adjustments to the Fuel Adjustment Rate ("FAR") should a rate adjustment cap as prescribed by the "PISA statute"[9] (Section 393.1400, .1655) be necessary. This change is necessitated by the terms of the statute.

Fourth, as is always done when a rate case occurs and a request to renew the FAC is made, we have updated the "charge type" table to include Midcontinent Independent

[8] Mantle Direct, File No. ER-2015-0285, p. 6, ll. 20-21.
[9] "PISA" stands for "Plant-in-service accounting."

System Operator, Inc. ("MISO") charge/revenue type changes since the last rate case and Southwest Power Pool ("SPP") charge types consistent with those listed for the MISO and PJM Interconnection markets since from time-to-time we have transacted (and may in the future transact) in SPP when it is prudent to do so.

Fifth, we have added a "Factor T" to the FAC tariff sheets and removed transmission costs from Factor PP. As Mr. Meyer explains in his direct testimony, while we have continued to follow the Commission's decision on what constitutes "true purchased power" and have updated the percentage of transmission services costs and revenues arising from sales and purchases for load in the MISO market accordingly, simply determining a percentage and applying it to all transmission services costs and revenues fails to account for transmission services costs associated with off-systems sales of energy. There has never been any claim that such transmission costs are not properly includable in the FAC but in order to properly capture them it is necessary to specify them in the FAC. Using a Factor T was the most straightforward way to do so. As noted, Mr. Meyer addresses the reason this change should be made in greater detail in his direct testimony.

Sixth, recent discussions with the Staff have indicated that it would make sense to line-up changes in FAC rates (called the "Fuel Adjustment Rate" or "FAR" in Rider FAC) with calendar months instead of billing months. The minor changes necessary to do so have been reflected in Schedule MLA-D3. The reason for this change is to ensure that rates are published in effective tariff sheets prior to the provision of service that will be subject to those rates.

Finally, we have updated BF amounts and Voltage Adjustment Factors for this case using, respectively, updated NBEC figures and an updated line loss study performed as required by the Commission's FAC rules. With regard to the Voltage Adjustment Factors, we have eliminated the transmission level factor because of the elimination of the 12(M) rate schedule. Company witness Michael Harding addresses the elimination of that rate schedule in his direct testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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)(A)1;

LOCAL PUBLIC HEARING NOTICE

Ameren Missouri has filed tariff sheets with the Missouri Public Service Commission (PSC) that would decrease the company's electric service revenues by approximately $800,000. The overall request would lower a typical residential customer's bill by approximately 0.03%, translating to an approximately $0.03 monthly decrease.

Ameren Missouri's rate filing also includes a request to continue its fuel adjustment clause ("FAC") 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 customers' bills. All of the reduction in base rates proposed in this case is caused by rebasing these net energy costs. In this case the reduction in costs due to the rebase of net energy costs is offset by net increases in other costs. If the net energy costs had not been rebased in this case, the base rates that would have been proposed in this case would have increased the typical residential customer's bill by 3.7%.

The permanent rate increase request, which is subject to regulatory approval, would take effect no later than May 30, 2020.

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(A)(2)2;

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

[1] Each item (A) …. (T) corresponds to the subparagraphs in 4 CSR 240-20.090(A)(2).

customers, and one in the billing format used by Ameren Missouri for its other customers).

(C) Proposed RAM tariff sheets in accordance with 4 CSR 240-20.090(2)(A)3;

Attached to the testimony to which this Schedule is attached as Schedule MLA-3 is Rider FAC - Fuel and Purchased Power Adjustment Clause, which are the proposed tariff sheets reflecting 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 detailed description of the design and intended operation of the proposed RAM in accordance with 4 CSR 240-20.090(2)(A)4;

As discussed in the testimony to which this Schedule is attached, Ameren Missouri is proposing to continue its existing 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 tariff sheets 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 eight 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 detailed explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity in accordance with 4 CSR 240-20.090(2)(A)5;

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

[2] Consistent with the Commission's *Order Approving Unanimous Stipulation and Agreement* in File No. ER-2016-0179, some transmission charges are excluded from the FAC. However, since some transmission charges (and revenues) remain in the FAC this schedule will refer to transportation including associated with purchased power.

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. 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 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 detailed explanation of how the proposed FAC shall be trued-up for over- and under-billing, or how the refundable portion of the proposed IEC shall be trued-up in accordance with 4 CSR 240-20.090(2)(A)6;

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 eight-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 detailed description of how the electric utility’s short-term borrowing rate will be defined and how it will be applied, during the accumulation period and the recovery period, to over- and under-billed amounts and prudence disallowances in accordance with 4 CSR 240-20.090(2)(A)7;

The short-term borrowing rate is developed separately for Ameren Missouri by the Ameren Services Company Treasury Department using the short-term borrowing balance outstanding at month end, the average daily short-term borrowing balance for the month, the weighted average short-term borrowing rate for the month, and the peak short-term borrowing amount for the month. The short-term borrowing instruments used in the development of the rate may include one or more of the following:

- Commercial paper
- Revolver (Credit Agreement) loans
- Term loans
- Regulated money-pool loans (Ameren Missouri Only)
- Non-regulated money pool loans (Ameren Corporation only)

The weighted average short-term borrowing rate is calculated based on the short-term borrowing balance for each instrument times the instrument's interest rate to calculate the daily interest. The average of the daily interest of all instruments is then divided by the average daily short-term borrowing balance of all instruments and multiplied by 360 days. In the event Ameren Missouri has no short-term borrowings for the month, then Ameren Corporation's weighted average short-term borrowing rate is used.

(H) A detailed description of how the proposed RAM is compatible with the requirement for prudence reviews in accordance with 4 CSR 240-20.090(2)(A)8;

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 240-20.090(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

[3] “S105” stands for 105 days after the end of the period covered by the settlement statement.

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.

(I) A detailed explanation of the fuel and purchased power costs, including transportation, that are to be considered for recovery under the proposed RAM with identification of the specific account and any other designation ordered by the Commission where the cost will be recorded on the electric utility's books and records in accordance with 4 CSR 240-20.090(2)(A)9;

These costs[4] are explained below 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 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.

Ash Disposal Costs. Cost to dispose of ash, net of ash revenues. These costs are expensed as incurred, with revenues reducing the total cost to dispose of ash.

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

[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.

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.

Fuel Additives. Cost of consumables such as urea, limestone and powder activated carbon used to operate Air Quality Control Systems (AQCS). 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 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. 100% of transmission costs to either transmit electric power sold to third parties (off-system sales), or to transmit electric power on a non-MISO system (excluding costs identified as administrative charges). In addition, 1.65% of transmission service charges recorded in FERC account 565 associated with Ameren Missouri's network transmission service (excluding costs identified as administrative charges) have been included, consistent with the methodology approved by the Commission in File No. ER-2016-0179.

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

(J) A detailed explanation of the fuel-related revenues that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the Commission where the cost will be recorded on the electric utility's books and records in accordance with 4 CSR 240-20.090(2)(A)10;

These revenues[6] are explained 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.

Transmission Revenues. 1.65% of transmission revenues recorded in FERC account 456.1 have been included, consistent with the methodology approved by the Commission in File No. ER-2016-0179.

(K) A detailed 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 in accordance with 4 CSR 240-20.090(2)(A)11;

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.

(L) A detailed explanation of any rate volatility mitigation features designed in the proposed RAM in accordance with 4 CSR 240-20.090(2)(A)12;

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 decreases that will occur as a result of the three periodic FAC adjustments each year.

[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.

Moreover, as discussed in Item (M) 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.

(M) A detailed explanation of any feature of the proposed RAM and any existing electric utility policy, procedure, or practice that ensures only prudent fuel and purchased power costs and fuel-related revenues are recovered through the proposed RAM, including, but not limited to, utilization of competitive bidding or other sourcing or sales practices in accordance with 4 CSR 240-20.090(2)(A)13;

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.

Fuel and Power Accounting

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

Coal, Oil, and Fuel Additives. 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 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, urea, limestone and activated carbon costs. All inventory, receivable, and payable accounts associated with coal, oil, and fuel additives 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 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.

Transmission of Electricity. MISO bills transmission customers and distributes revenues to transmission owners, including Ameren Missouri, directly through monthly revenue (MR) and monthly cost (MC) files. The MR and MC files are received from the MISO website via secure FTP. A Transmission Policy Specialist creates a monthly summary showing revenues and expenses by schedule for each market participant. The Transmission Policy Specialist researches any exceptions and determines whether the exception requires a dispute to be filed with MISO. Once satisfied, the Transmission Policy Specialist sends the validated MR and MC file to Power Accounting. Power Accounting uses the MR and MC monthly summary file to record monthly transmission revenues and expenses in the general ledger based on the MISO schedule and market participant. 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.

Fuel and Power Procurement

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. The Company performs a control process daily to validate appropriate transactional processing.

(N) A detailed explanation of any change to the electric utility's business risk resulting from implementation of the proposed RAM, in addition to any other changes in business risk the electric utility may experience in accordance with 4 CSR 240-20.090(2)(A)14;

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 level of efficiency for each of the electric utility's generating units within twenty-four (24) months preceding the filing in accordance with 4 CSR 240-20.090(2)(A)15;

The Company is supplying the results of the heat rate tests and monitoring for the Company's currently-in-service generating units over the previous 24-months as part of its workpapers being provided in connection with its direct case filing. The results will be in a separate workpaper specifically denominated as such.

(P) Information that shows that the electric utility has in place a long-term resource planning process in accordance with 4 CSR 240-20.090(2)(A)16;

On September 25, 2017, Ameren Missouri made its most recently required triennial Integrated Resource Plan ("IRP") filing (EO-2018-0038), 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 ensure 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 2018 IRP Annual Update report with the Missouri Public Service Commission (PSC) in March 2018 and its 2019 IRP Annual Update report in March 2019. Ameren Missouri's next triennial IRP filing is due October 1, 2020.

(Q) A detailed explanation of Ameren Missouri's emissions management policy, and its forecasted environmental investments, emissions allowances purchases, and emission allowances sales in accordance with 4 CSR 240-20.090(2)(A)17;

Ameren Missouri has an established a plan to comply with the new Cross State Air Pollution Rule (CSAPR) that was initially finalized by USEPA in July 2011 and subsequent revisions. Ameren Missouri's strategy for SO2 compliance is to continue operation of the wet flue gas desulfurization (FGD), or "scrubber" systems, at the Sioux energy center coupled with purchase of ultra-low sulfur coal for the balance of our coal fired units at Labadie, Meramec and Rush Island. Also note that beginning in April 2016 only natural gas is fired in Meramec units 1 and 2 that results in a significant reduction in emissions from those units. No additional capital projects are necessary or planned for SO_2 compliance over the next five years. Ameren Missouri's strategy for NO_x compliance was to continue operation of low NO_x burner (LNB) and over-fire air (OFA) systems at the coal-fired energy centers as well as neural net optimization systems to enhance NO_x emission reduction. In addition, the installed selective noncatalytic reduction (SNCR) systems at the Sioux Energy Center were tuned and available for use if needed for additional NO_x reduction.

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 SO_2 and NO_x tons during the first phase and use these as necessary to comply with the second phase. As the SO_2 bank was projected to be significantly larger than the NO_x bank, swapping SO_2 allocations for NO_x 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 SO_2 and NO_x allowances under the CSAPR. Ameren Missouri is in compliance with the current Phase 2 limits of the CSAPR with its installed pollution control equipment, low sulfur coal and natural gas and currently has sufficient allowances for compliance in future years.

(R) Graphs for each month of the preceding five years showing the monthly equivalent availability factor, forced outage rate, and the length and timing of each planned outage for each of the Company's generating units are contained in Attachment D in accordance with 4 CSR 240-20.090(2)(A)18;[8]

(T) The Company authorizes the Staff to release to all parties to this case its previous five years of historical surveillance monitoring reports in accordance with 4 CSR 240-20.090(2)(A)19.

[8] The Company's direct case workpapers to be provided to the parties to this case contain the data underlying these graphs.

Ameren MISSOURI

- AmerenMissouri.com
- 1.800.552.7583
- PO Box 790352 St. Louis, MO 63179-0352

for correspondence only

Ways to Reach Us

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Current Charge Detail for Statement 04/04/2017

Electric Energy Charge - Residential	$20.33
Electric Customer Charge - Residential	$8.13
Fuel Adjustment Charge	$0.29
Energy Efficiency Investment Charge	$0.92
St. Louis City Municipal Charge - Service	$1.24
Current Charge	**$30.91**
Budget Bill Adjustment	$33.09
Budget Bill Amount	**$64.00**
Amount Due	**$64.00**

Current Charge Details

AMOUNT DUE	**$64.00**
Due Date:	**04/26/2017**
Account Number	1234567890
Customer Name	JOHN DOE
Service Address	1234 MAIN STREET
Previous Statement	$64.00
Last Payment - 03/30/2017	$64.00

Total Amount Due

Your Budget Billing balance is ahead $165.21 after paying this bill.

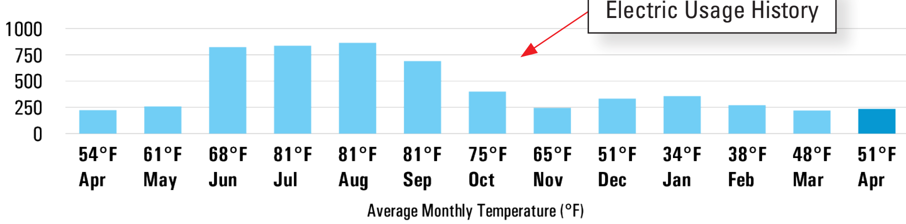
Electric Service from 03/03/2017 - 04/03/2017 31 Days

	Meter Number	Current Reading	Previous Reading	Current Usage	Reading Type
E	39365701	019761	019526	235 kWh	Actual

Service

Electric Service Details April Statement

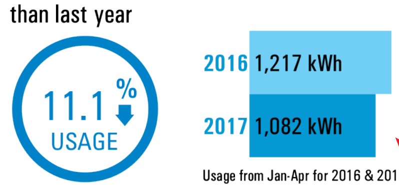
Electric Usage in Kilowatt Hours (kWh)



Electric Usage History

Electric Usage Summary (kWh)

So far this year, you're using **11.1% less** than last year



Usage from Jan-Apr for 2016 & 2017

Electric Usage Summary

13073
00069 2252084 000069 000137 0001/0001
INTERNAL USE ONLY

Save $100 On An Eligible Smart Thermostat.

Purchase an eligible smart thermostat and get $100 cash back, plus so much more. Benefits include:

- Ability to control the temperature from your mobile phone
- Smart technology that autoprograms your temperature preferences and adjusts for when you are home or away

Visit **AmerenMissouri.com/products** to find a retailer near you.

Energy Savings Tips

> > See reverse for messages

Please return this portion with your payment.

Ameren MISSOURI

Amount Due & Due Date

AMOUNT DUE	Due Date
$64.00	April 26, 2017
Delinquent Amount After Due Date	**Account Number**
$64.96	1234567890
Amount Enclosed: $	

☐ Check if you have address changes on back.

>000069 2252084 0002 092139 10Z

JOHN DOE
1234 MAIN STREET
ANYTOWN, USA 12345-6789

Remittance Address

AMEREN MISSOURI
PO BOX 88068
CHICAGO IL 60680-1068

Attachment A

0220000 002070101106 00064960 00064000 00064000

Ameren MISSOURI

- AmerenMissouri.com
- 1.800.552.7583
- PO Box 790352 St. Louis, MO 63179-0352

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Account Messages

The Missouri Public Service Commission has approved a 3.5% overall increase in Ameren Missouri's electric rate levels that took effect on April 1, 2017. For information about these changes, please visit AmerenMissouri.com or contact customer service at 1.800.552.7583. Your electric service charges for this billing period are being prorated. Proration occurs when part of your bill is calculated on old rates and part of your bill is calculated on new rates.

Account Messages

We have replaced the Electric Charge line item on your energy statement with two descriptive, separate line items. These are not new charges. The Electric Customer Charge line item reflects the fixed cost of providing you service while the Electric Energy Charge line item varies with your electricity consumption. Visit AmerenMissouri.com/statement for more information.

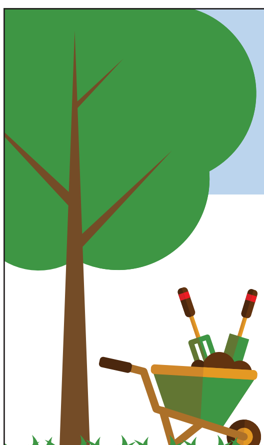
A late payment charge of 1.5% will be added for any unpaid balance on all accounts after the due date.

SPEEDPAY offers 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.

Your Budget Billing plan will settle with next month's bill. Any difference between your actual usage and the estimated amount billed will be reflected as 'Budget Bill Adjustment' on your next bill.



Spring Has Sprung.

Spring is here and the warmer weather makes it a good time for yard work and other outdoor activities. No matter what's on your agenda, electrical safety should be an important part of your plans.

Call Before You Dig. Protect yourself and your utility services by calling **8.1.1.** before planting trees, gardens or digging in your yard. Having underground lines properly marked helps prevent service disruptions and injuries.

Right Tree, Right Place. Planting the right species of tree in the right place prevents interference with your service and ensures trees are an asset to you and your community. Find planting tips at **AmerenMissouri.com/trees.**

Be Aware. Be Prepared. If your property is damaged by storms, don't remove debris near or touching power lines. Assume all downed lines are energized and call us at **1.800.552.7583** to report the location.

Address Changes or Corrections

Address Change

Name ______________________________

Address ______________________________

City, State, Zip ______________________________

Phone Number ______________________________

AmerenMissouri.com/WaysToPay

ONLINE E-CHECK

PHONE 866.268.3729

IN PERSON FIND A PAY STATION AT AMERENMISSOURI.COM/PAYSTATION

ONLINE CREDIT CARD

MAIL STUB & CHECK

Attachment A

Ameren MISSOURI

- AmerenMissouri.com
- 1.877.426.3736
- PO Box 88068 Chicago, IL 60680-1068

Ameren payment processing center

FOCUSED ENERGY. For life.

Account Number **2501009818**
Customer Name COMMUNITY SOLAR SAMPLE BILL
Service Address 1481 HAWKINS RD
FENTON, MO 63026

Current Detail for Statement 10/16/2018

Total Electric Charges	$668.55
Total Amount Due	**$668.55**

AMOUNT DUE	**$668.55**
Due Date	**10/26/2018**
Amount After Due Date	$678.58
Previous Statement	$2,162.52
Total Payments	$2,162.52

Payment Received. Thank You.

Electric Service Details **Service from 10/15/2018 - 11/14/2018 (30 days)**

Electric Meter Read

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
80982455	10/15 - 11/14	30	Total kWh	Actual	14738.0000	14078.0000	660.0000	10.0000	6600.0000
80982455	10/15 - 11/14	30	Peak kW	Actual	3.2480	0.0000	3.2480	10.0000	32.4800

Usage Summary

Total kWh	6600.0000	Solar kWh	300.0000
Seasonal kWh-Solar	0.0000	Current Base kWh	6300.0000

13073
00001 6019327 000001 000001 0001/0001

» See next page for service details.

Keep this portion for your records.

Please return this portion with your payment.

Ameren MISSOURI

☐ Check if you have address changes on back.

Amount Due	Due Date
$668.55	October 26, 2018
Delinquent Amount After Due Date	**Account Number**
$678.58	2501009818

Amount Enclosed $ ______________

>000001 6019327 0001 092139 10Z

COMMUNITY SOLAR SAMPLE BILL
COMMUNITY SOLAR SAMPLE BILL
PO BOX 790352
SAINT LOUIS, MO 63179-0352

AMEREN MISSOURI
PO BOX 88068
CHICAGO IL 60680-1068

Attachment B

80000000 2501009810800 000066855000 0000668550

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- AmerenMissouri.com
- 1.877.426.3736
- PO Box 88068 Chicago, IL 60680-1068

Ameren payment processing center

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Electric Service Details (Continued)

2M Sm Gen Svc - 3 Ph w/Dmd

Threshold -Peak Demand   Community Solar

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Base Energy Charge	6,300.00	kWh	@	$0.08360000	$526.68
Seasonal kWh-Solar	0.00	kWh	@	$0.04820000	$0.00
Community Solar Energy Charge	300.00	kWh	@	$0.13090000	$39.27
Customer Charge					$21.43
Fuel Adjustment Charge	6,600.00	kWh	@	$0.00196000	$12.94
Energy Efficiency Program Charge	6,300.00	kWh	@	$0.00010000	$0.63
Energy Efficiency Investment Charge	6,600.00	kWh	@	$0.00449900	$29.69
Federal Tax Rate Reduction	6,600.00	kWh	@	-$0.00581000	$-38.35
				Total Service Amount	**$592.29**

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Missouri State Sales Tax	$592.29		@	$0.04225000	$25.02
Missouri Local Sales Tax	$592.29		@	$0.03388000	$20.07
St Louis Co Municipal Charge - Service	$592.29		@	$0.05263000	$31.17
				Total Tax Related Charges	**$76.26**
				Total Electric Charges	**$668.55**

Payments Since Previous Statement

DATE RECEIVED	AMOUNT
November 04, 2018	$2,162.52

Questions? Contact Ameren Missouri at **1.877.426.3736** or visit **AmerenMissouri.com**.

Address Changes or Corrections

Name ____________________

Address ____________________

City, State, Zip ____________________

Phone Number ____________________

AmerenMissouri.com/WaysToPay

ONLINE E-CHECK

PHONE 866.268.3729

IN PERSON FIND A PAY STATION AT AMERENMISSOURI.COM/ PAYSTATION

ONLINE CREDIT CARD

MAIL STUB & CHECK

Attachment B

Ameren Missouri
Account and Sub-account Descriptions

For FC = Fuel cost and revenues associated with the Company's generating plants in FERC accounts 501, 502, 547 and 518

INCLUSIONS:

FAC Subparagraph #	Major	MIN/RT	Activity Code	Description
1 A:	501			FERC Account 501 contains costs/revenues associated with the fuel used in the production of steam for the generation of electricity.
		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 railcar lease termination fees to allow for 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.
		006 016 *All RTs that DO NOT start with L		Costs/revenues associated with coal ash disposal such as: - physical disposal costs. - trucking services. - coal ash sales.
B:	502			FERC 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.
		007		Cost of Urea (including truck transportation costs) used as part of air quality control operations at the coal fired plants.
C:	547			FERC 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 / FI		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			FERC 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.
		005		Costs associated with the disposal of nuclear fuel waste.

EXCLUSIONS:

FAC Subparagraph #	Major	Minor/Resource Type	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 (labor related)		
		016 * All RTs that start with L (labor related)		
		020		
		030		
	502			Costs/revenues associated with labor, materials and supplies inventory, and SO2 tracker amortization.
		000		
		006		
	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.
Activity Code ("ACTV") is not used to distinguish costs for inclusion in the FAC for FERC accounts 501, 518 or 547.

Attachment C

Ameren Missouri
Account and Sub-account Descriptions

For PP = Purchased power costs and revenues in FERC account 555:

INCLUSIONS:

FAC Subparagraph #	Major	Minor	Activity Code	Description
A: i:	555	MIS		FERC Account-555 contains costs directly related to Purchased Power Subaccount: (Minor) = MIS All MISO costs associated with the below listed 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.		MIS or PRY	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.		MIS	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.
			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.
c.			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.			DRAU	A MISO charge for Real Time Demand Response Allocation Uplift. This is a charge type used to collect Demand Response Compensation when the LMP Demand Response Resource exceeds the Net Benefits Price Threshold.
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:				Subaccount (Minor): PJM Interconnection and/or SPP (Southern Power Pool) - Regional Transmission Operators
		PJM and SPF	PPIS	Net energy purchases allocated to net sales other than native-load
		PJM and SPF	PPBL	Net energy purchased for native-load.
		PJM	PLOS	The component of locational marginal price (LMP) associated with energy losses.
		PJM	PCNG	The component of the locational marginal price (LMP) associated with implicit system congestion.
		PJM	PRSG	Balancing Operating Reserve – Equivalent to Revenue Sufficiency Guarantee in MISO
		PJM	PFTR	Net costs associated with FTRs and ARRs
		PJM	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.

		SPP	MLOS	The component of locational marginal price (LMP) associated with energy losses (corresponding to MISO losses).
		SPP	MCNG	The component of the locational marginal price (LMP) associated with implicit system congestion (corresponding to MISO congestion).
		SPP	MRSG	Reliability Unit Commitment Make Whole Payment (corresponding to Revenue Sufficiency Guarantee in MISO).
		SPP	MRNU	Revenue Neutrality Uplift Charge, (corresponding to MISO RNU).
		PJM and SPP	RFRS	Ancillary services - Charges for Reserve and Regulation services (corresponding to MISO Regulating Reserve).
		PJM and SPP	SPRS	Ancillary services - Charges for Spinning Reserve (corresponding to MISO Spinning Reserve).
		PJM and SPP	SURS	Ancillary services - Charges for Supplemental Reserve (corresponding to MISO Supplemental Reserve).
ii: a.		All minors excluding MIS, PJM or SPP		Subaccount (Minor): Used to primarily distinguish counterparties for managerial reporting All non-MISO, PJM and SPP costs associated with the below listed items/activity codes:
			PPBL	Net energy purchases allocated to native-load sales
			PPIS	Net energy purchases allocated to all sales other than native-load
b.			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
C:		XXX		Realized losses and costs (including broker commissions and fees) for financial swap transactions to mitigate volatility.

EXCLUSIONS:

FAC Subparagraph #	Major	Minor	Activity Code	Description
	555	MIS		Costs associated with MISO schedules that are specifically excluded
			SC24	Control area recovery
			SC34	Penalty Assessment
			MDEV	RTO uninstructed deviation
			PSIM	Product & Svc implementation
			REEA	Renewable energy/energy assistance
	555	*Various*	*Various*	Amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff will be distinguished by business division (**TBD**).

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.

Ameren Missouri
Account and Sub-account Descriptions

For T = Transmission costs and revenues in FERC accounts 565 and 456.1:

INCLUSIONS:

FAC Subparagraph	Major	Minor	Activity Code	Description
1:	565			Transmission service costs to (a) transmit excess electric power sold to third parties to locations outside of MISO (off-system sales)(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule) or; (b) transmit electric power on a non-MISO system are distinguished by business division (**TBD**)
2:	565			Transmission service costs directly attributable to Ameren Missouri's network transmission service (excluding (a) amounts associated with portions of Purchased Power Agreements dedicated to specific customers under the Renewable Choice Program tariff and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule) are distinguished by business division (**TBD**)
1 and 2 A:	565	MIS		FERC Account 565 contains costs related to the Transmission of Electricity by Others. Subaccount (Minor): MIS 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 Perry. 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
			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
			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
			S26C	RTO Amounts for Schedule 26-C: Cost Recovery for Targeted Market Efficiency Projects (TMEP) Constructed by MISO Transmission Owners Transmission charge that provides the mechanism for recovery of the revenue requirements for TMEPs constructed by MISO Transmission Owners. The TMEPs are an interregional transmission project type between MISO and PJM intended to reduce historical congestion along the border between MISO and PJM to benefit customers and improve coordination between the two RTOs.
			S26D	RTO Amounts for Schedule 26-D: Cost Recovery for Targeted Market Efficiency Projects (TMEP) Constructed by PJM Interconnection, LLC Transmission Owners Transmission charge that provides the mechanism for recovery of the revenue requirements for TMEPs constructed by PJM Transmission Owners. The TMEPs are an interregional transmission project type between MISO and PJM intended to reduce historical congestion along the border between MISO and PJM to benefit customers and improve coordination between the two RTOs.

			SC37	RTO amounts for Schedule 37 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for American Transmission System, Inc. (ATSI) Zone 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) 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.
1 and 2 B:	565	All others		Subaccount (Minor): Used to distinguish Non-MISO counterparty transactions for FERC Form reporting (ex: 565PJM and 565SPP)
			SC26	SPP Base Plan Zonal Charge - The remainder of the costs of facilities, after the Base Plan Regional Charge, which is allocated to the zone in which each facility is located. (Corresponds to MISO Schedule 26.)

			S26A	SPP Base Plan Regional Charge - Charges to facilities whose costs are shared in whole or in part on a regional postage stamp basis. (Corresponds to MISO Schedule 26A.)
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 transmission charges related to Network Integration Transmission Service, Transmission Enhancement, Non-Firm Point-to-Point Transmission Service, Black Start Service and Expansion Cost Recovery.
			SC08	Non Firm Point to Point Transmission Service. (Corresponds to MISO Schedule 8.)
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.
			SC02	Charges for Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.
3 A & B:	456			FERC Account: 456.1 Revenues from Transmission of Electricity of Others Subaccount (Minor): Primarily used to distinguish counterparty; Subaccount (Activity Code) used to distinguish transmission revenues All MISO and Non-MISO revenues associated with the below listed
			MISO	This is considered a miscellaneous MISO transmission revenue transaction and is not covered by other activity codes listed herein as it is not a recurring item.
			SC24	RTO Schedule 24 - Control area recovery for cost recovery for providing balancing services as the Local Balancing Authority.

i:			TSEN	Transmission Sales related to Network Transmission Services (Schedule 9) - Network 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) are designated to serve these loads
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.
3 A 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

			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
			SC37	RTO amounts for Schedule 37 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for American Transmission System, Inc. (ATSI) Zone 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) 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
			S42A	Charge to Recover Accrued and Paid Interest Associated with Prepayments From Entergy Operating Companies' Pricing Zones
			S42B	Credit Associated with AFUDC From Entergy Operating Companies' Pricing Zones
			SC45	Cost Recovery of NERC Recommendations or Essential Action
			SC47	Entergy Operating Companies MISO Transition Cost Recovery

Note: All FERC account 456.1 values are recorded in the general ledger under account 456. The activity code within Ameren's general ledger code block is used to distinguish those amounts that are specific to FERC account 456.1, and are includable in Rider FAC, and those that are specific to FERC account 456 which are excluded from Rider FAC.

EXCLUSIONS:

FAC Subparagraph	Major	Minor	Activity Code	Description
	456			Revenues associated with FERC account 456.1 which are on MISO schedules specifically excluded from the FAC.
			SC10	RTO Schedule 10 - Cost Recovery Adder
	456			Revenues that are not currently part of FERC account 456.1 and therefore are not included in the FAC calculation.
			DFAC	Wholesale Distribution Connection Facility revenues
			ACOS	Accounting Offset
			GRTX	Gross Receipts Tax
			ARSS	Asset Recovery - Scrap & Salvage
			LMPM	Property Management
			MFTR	RTO Financial Transmission Rights
			MRNU	RTO Revenue Neutrality Uplift
			NENR	Non-Energy Revenues
			PLND	Distribution Planning/Asset Performance
			REEA	Renewable Energy/Energy Assistance
			RFRS	RTO Ancillary Regulation & Frequency Reserve
			RQGR	Customer Requests - Government Relocation
			SCOF	Customer Sales - Off System
			SCON	Customer Sales - On System
			SPRS	RTO Ancillary Spinning
			SURS	RTO Ancillary Supplemental
			TXPY	Tax Payments

Ameren Missouri
Account and Sub-account Descriptions

For E = Costs and revenues for SO and NO_x emissions allowances in FERC accounts 411.8, 411.9 and 509

INCLUSIONS:

FAC Subparagraph #	Major	Minor	Activity Code	Description
	411	008		FERC Account 411.8 contains gains from the disposition of emission allowances.
		009		FERC Account 411.9 contains losses on the disposition of emissions allowances.
	509	000		FERC Account 509 contains 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.

Note: Activity Code ("ACTV") is not used to distinguish costs for inclusion in the FAC for FERC accounts 411.8, 411.9 or 509.

For R = Net insurance recoveries for costs/revenues included in Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included Rider

INCLUSIONS:

FAC Subparagraph #	Maj	Min/RT	Activity Code	Description
	To be determined	To be determined	To be determined	Net insurance recoveries for costs/revenues included in Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included Rider FAC.

Attachment C

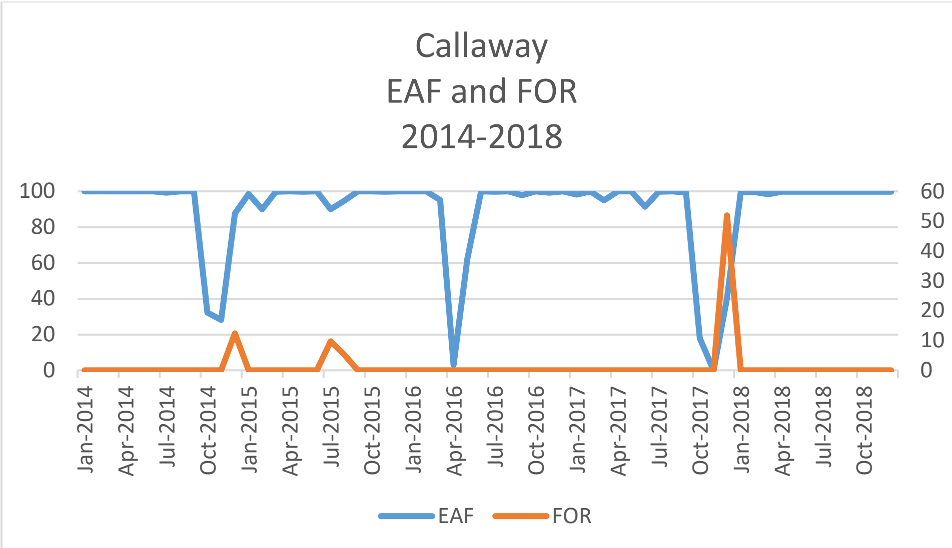
For OSSR = Costs and revenues in FERC account 447:

INCLUSIONS:

FAC Subparagraph #	Major	Minor	Activity Code	Description
1:	447			FERC Account 447 contains revenues related to net off-system sales Subaccount (Minor): used to distinguish 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 X	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)
		998	ADMN	Supplier fees associated participation in Illinois Power Agency procurements.
3:		All minors	SRMP	An ancillary service charge type which is used to account for revenues associated with dispatch interval adjustments that are needed, using a 10-minute forecast of Net Load plus forecast uncertainty, in order to ensure sufficient system ramp capability.
A:			RFRS	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.
			NRGA	Ancillary Services – Regulating Reserve Service A MISO charge for Real Time Net Regulation Adjustment Amount. This charge type represents charges or credits to a Resource providing deployed Regulation Service such that the Resource is indifferent to deploying Energy above or below its Dispatch Target for Energy to provide the Regulation Services.
			DEDC	Ancillary Services – Regulating Reserve Service This is a "Real Time Excessive/Deficient Energy Deployment Charge" which is a MISO charge that represents the charge to an Asset Owner owning Generation where the Asset Owner's unit fails to follow MISO setpoint instructions for 4 consecutive intervals within 1 hour without an exception.
			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
			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.
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 for Ameren Missouri generating units not deployed.
4 A:			PMWP	Price volatility Make Whole Payment A MISO charge for Real Time Price Volatility Make-Whole Payment Amount. This charge provides compensation for market conditions that would erode the margin earned.
B:			DMWP	Day-Ahead RSG Make Whole Payment A MISO charge for Day Ahead Revenue Sufficiency Guarantee Make Whole Payment. This is a charge type for the guaranteed recovery of production offers for Resources committed by MISO for the Day-Ahead Market.
			RMWP	Real-Time RSG Make Whole Payment A MISO charge for Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount. This is a charge type for the guaranteed recovery of production offers for Resources committed by MISO for the Real-Time market.
5:		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

EXCLUSIONS:

FAC Subparagraph #	Major	Minor	Activity Code	Description
	447	*Various*	*Various*	Amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff and (c) amounts associated with generation assets that began commercial operation after the date BF was determined and that were dedicated to specific customers under the Renewable Choice Program tariff when it began commercial operation) distinguished by business division (**TBD**).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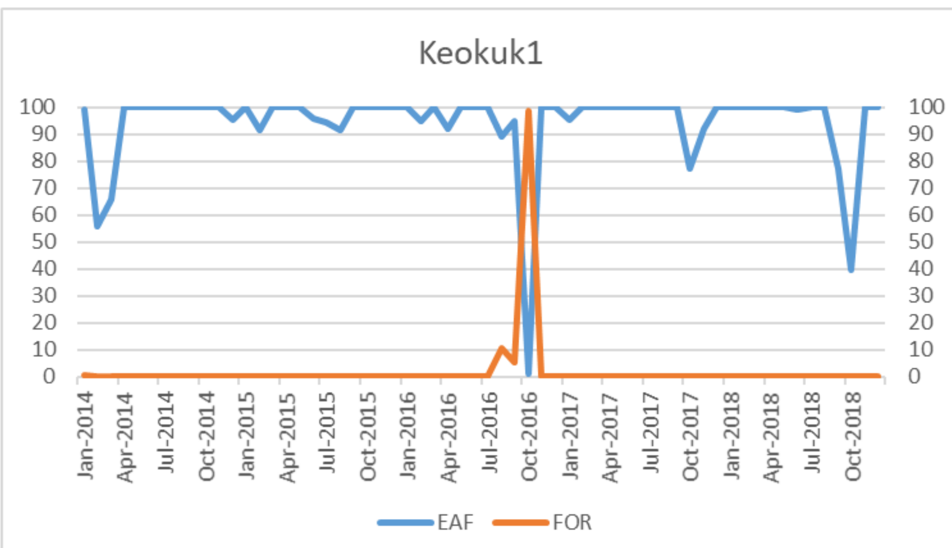
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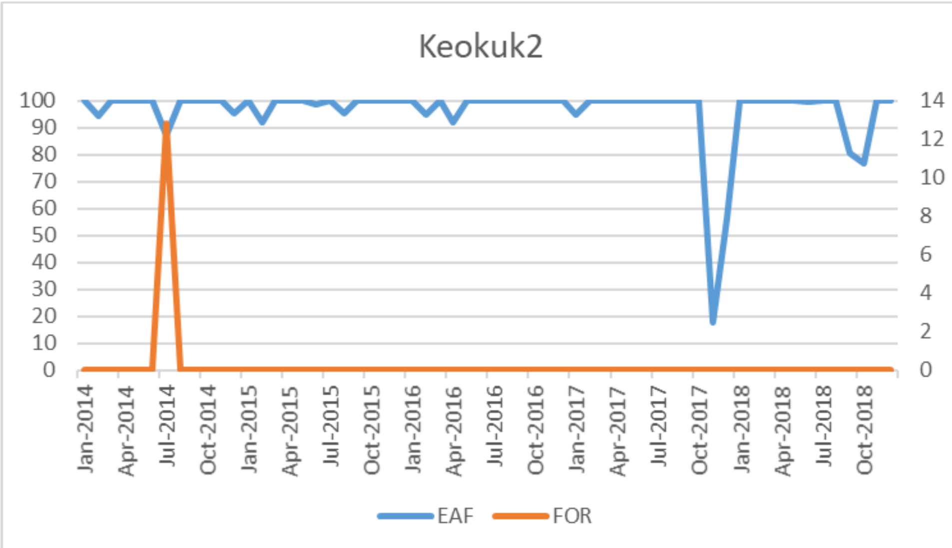
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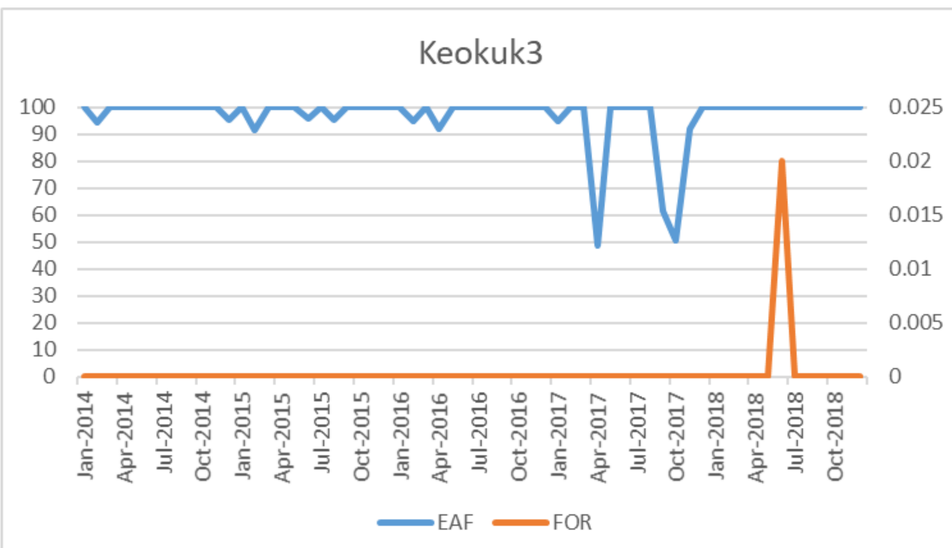
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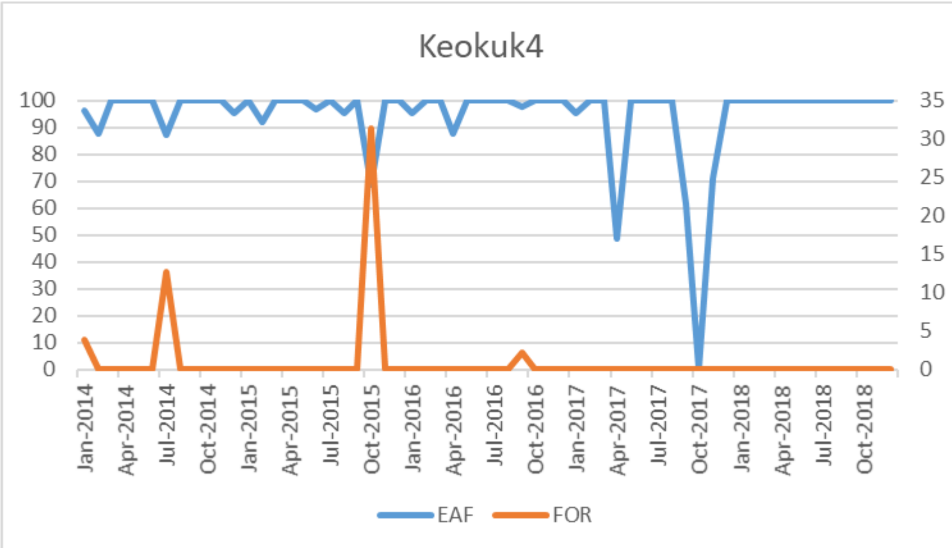

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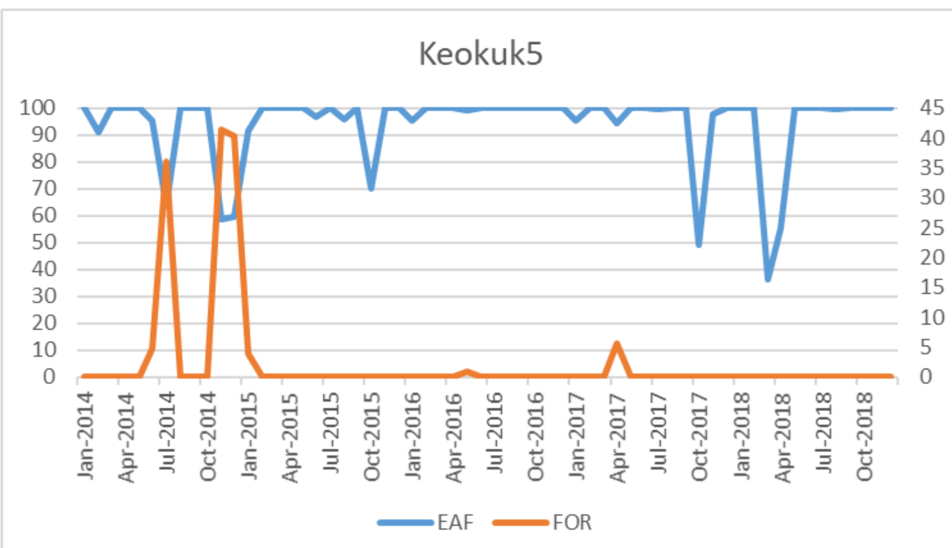

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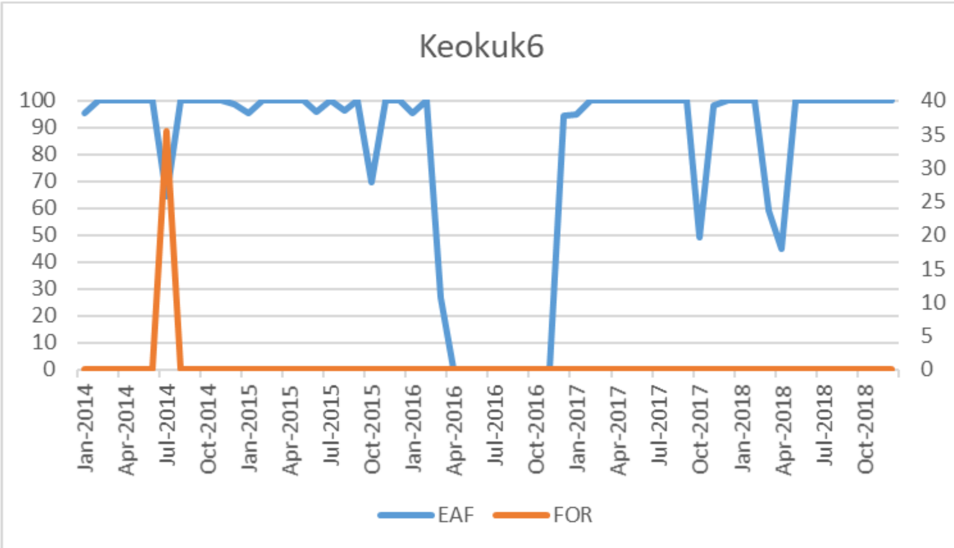
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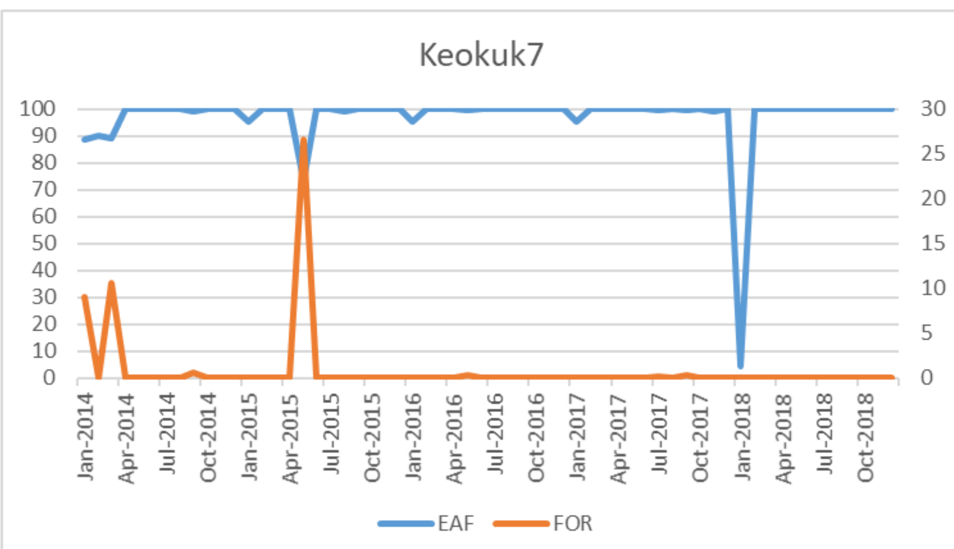
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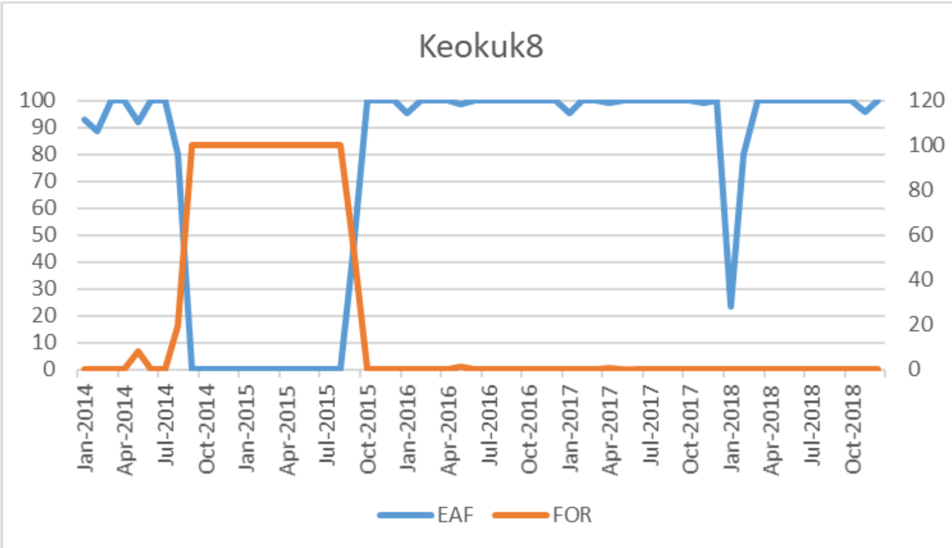

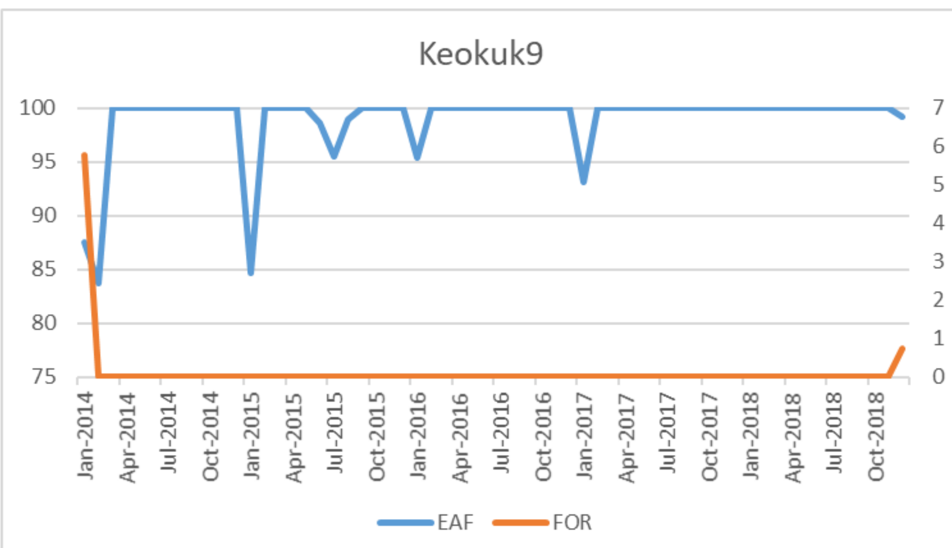

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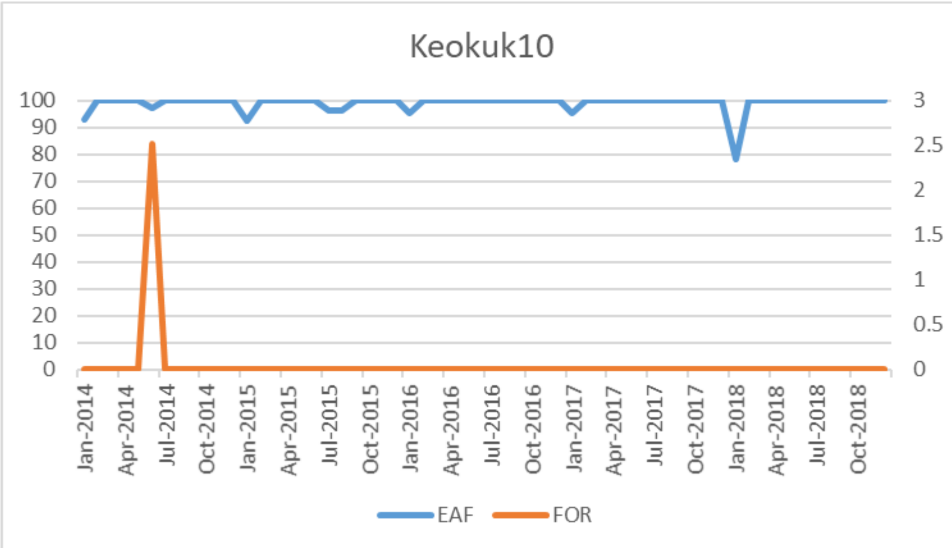
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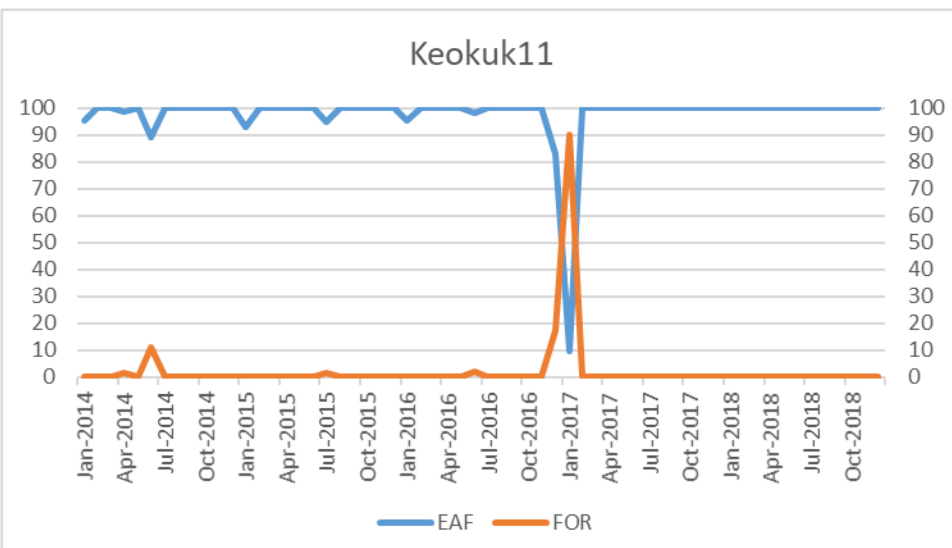
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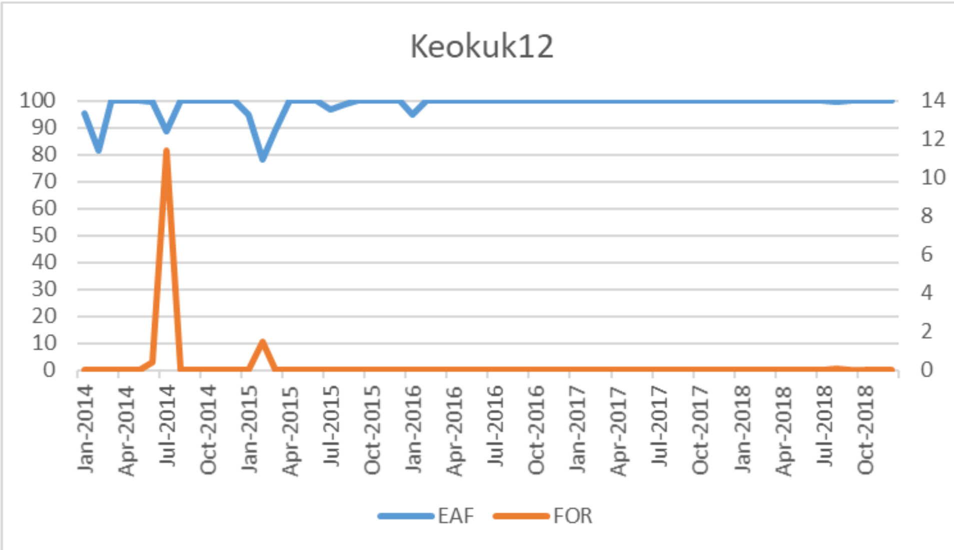
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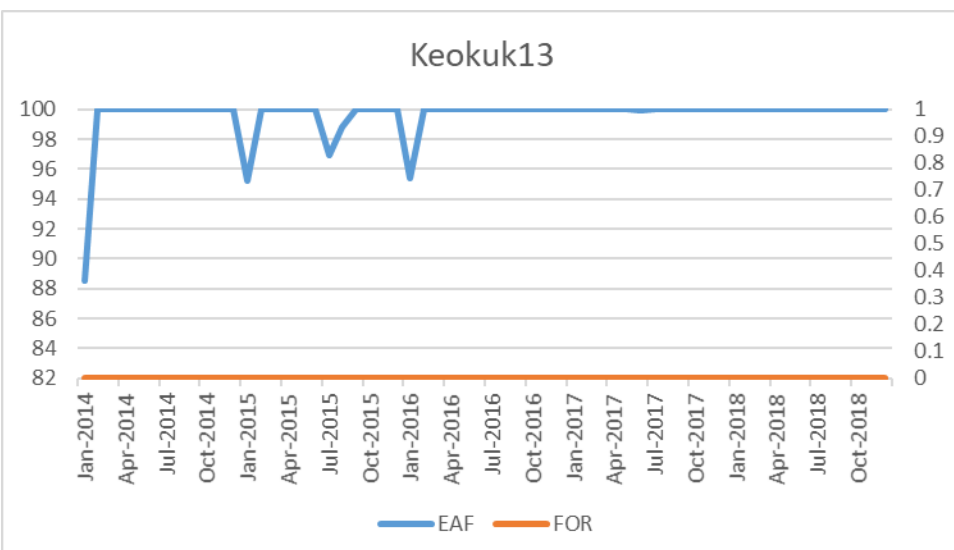
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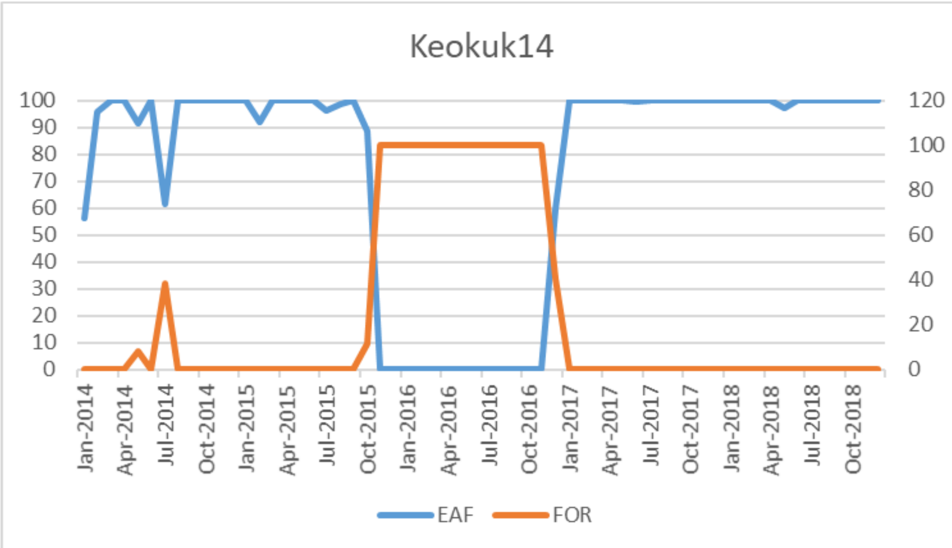
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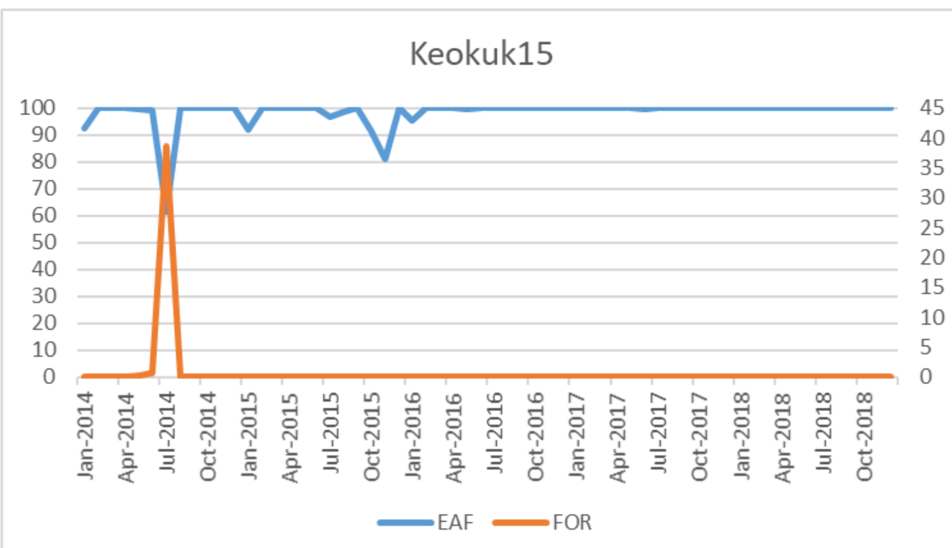
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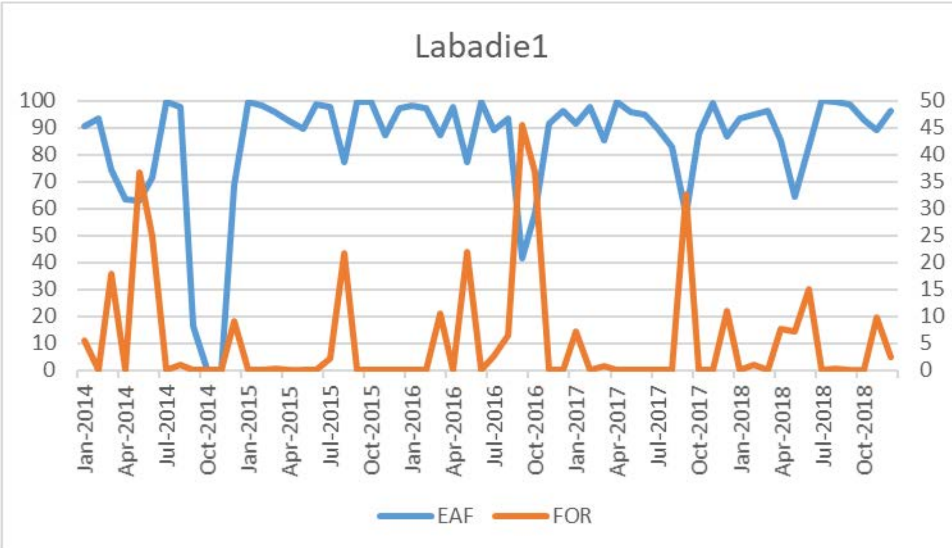
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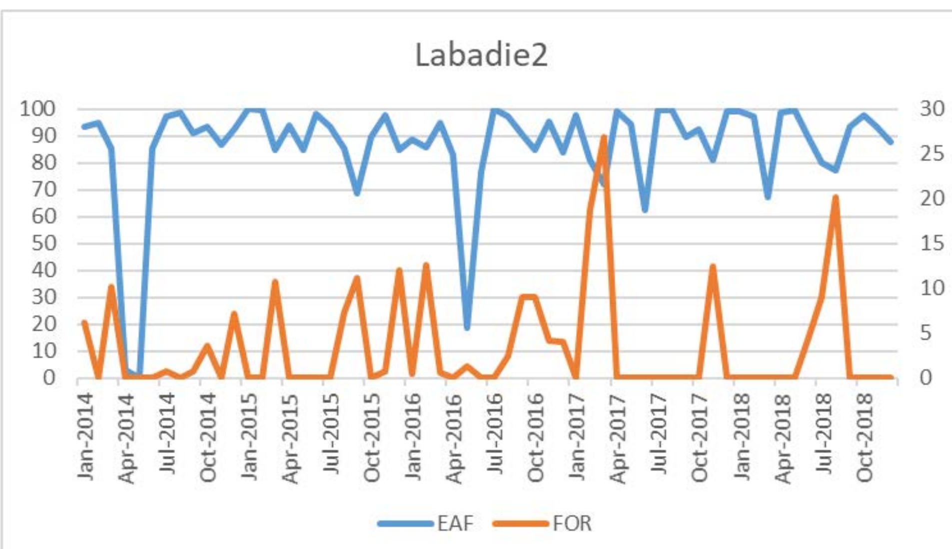
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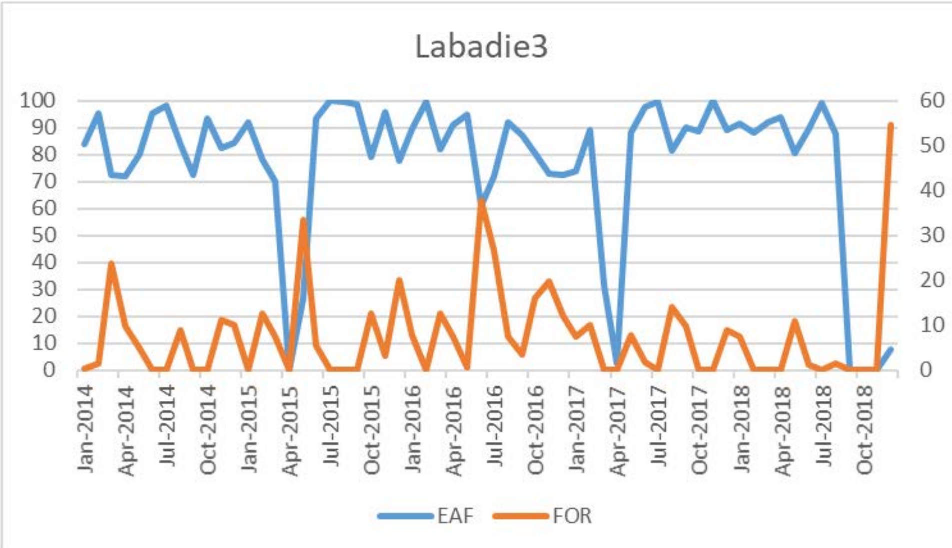
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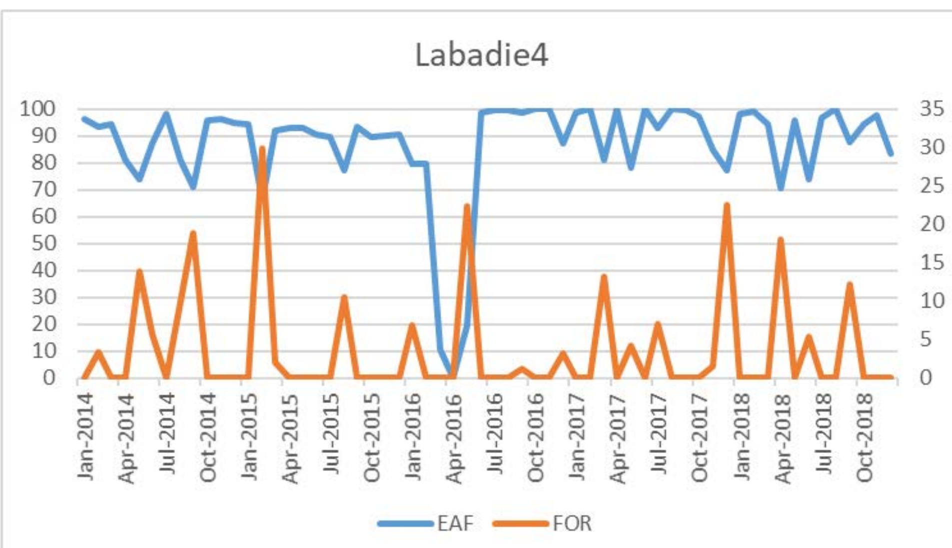
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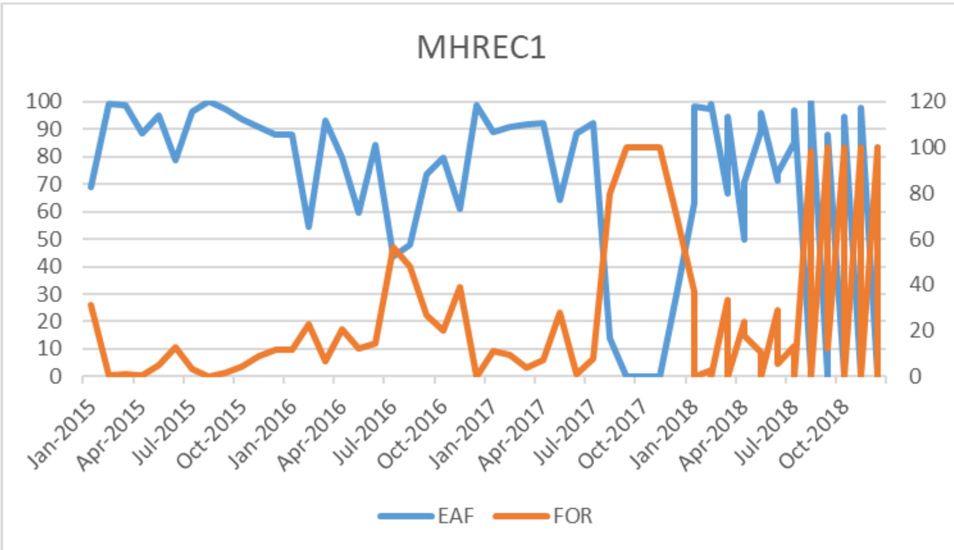
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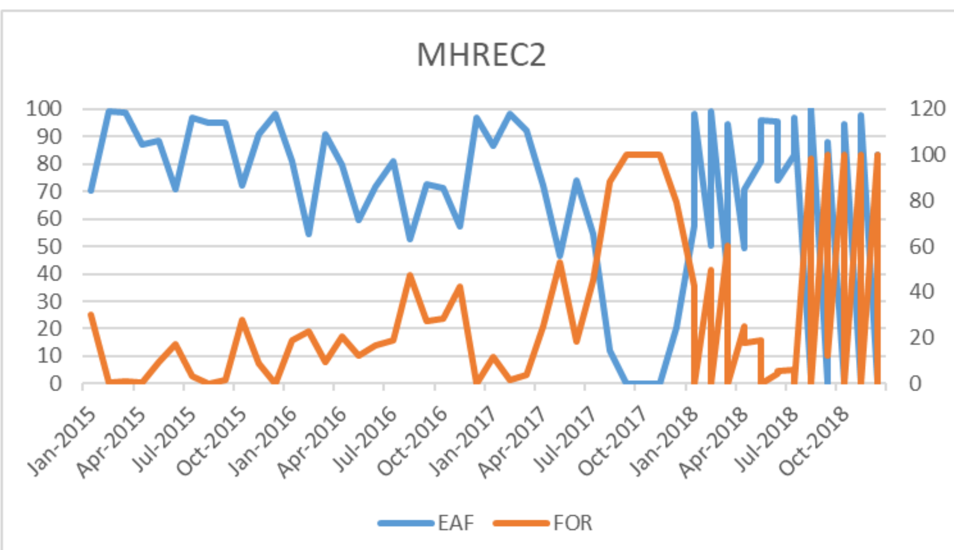
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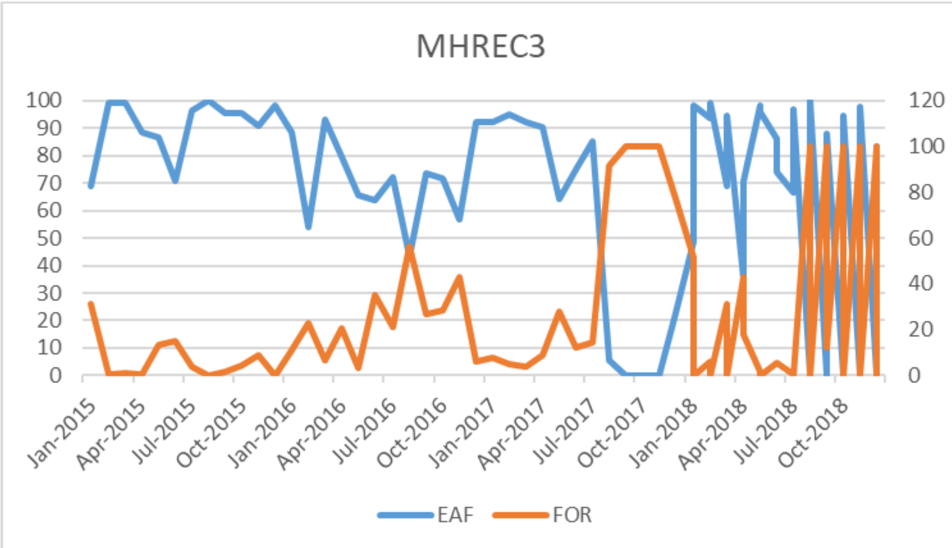
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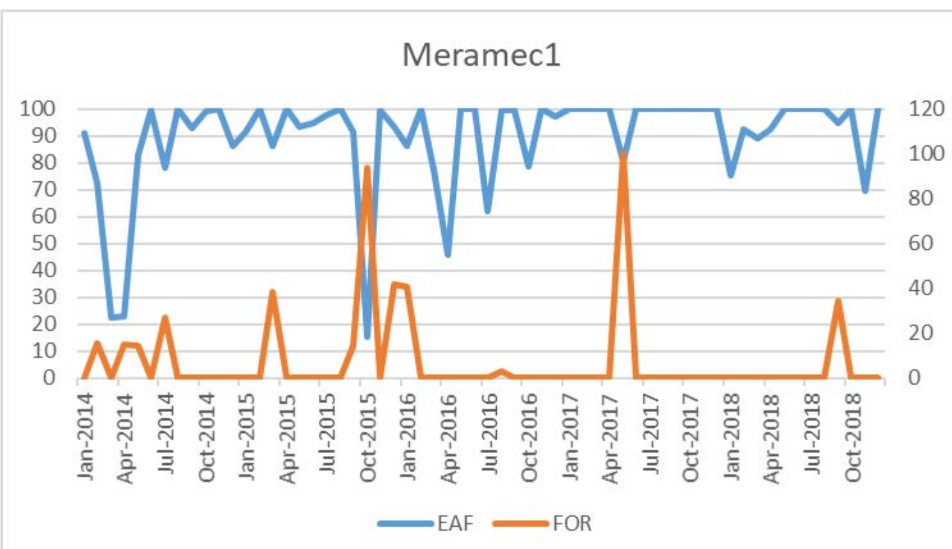
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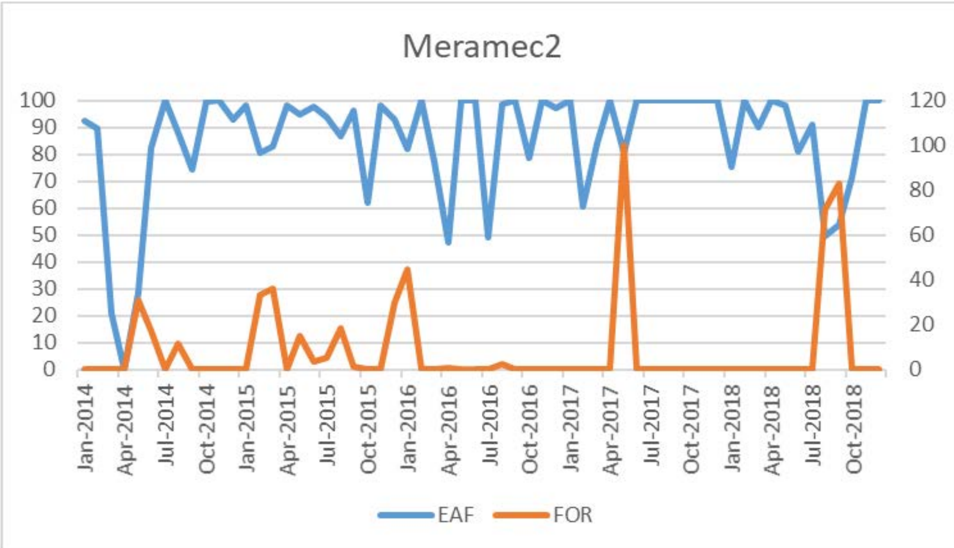
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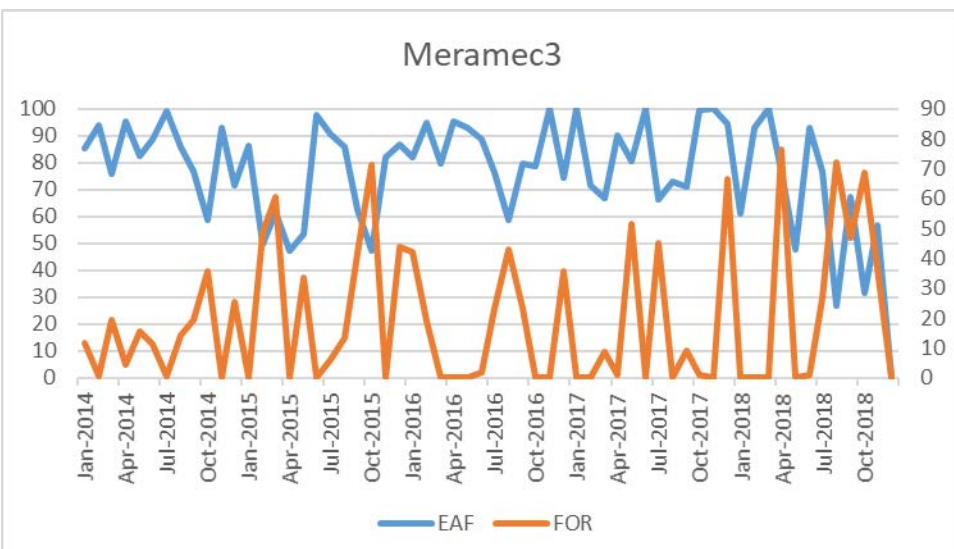
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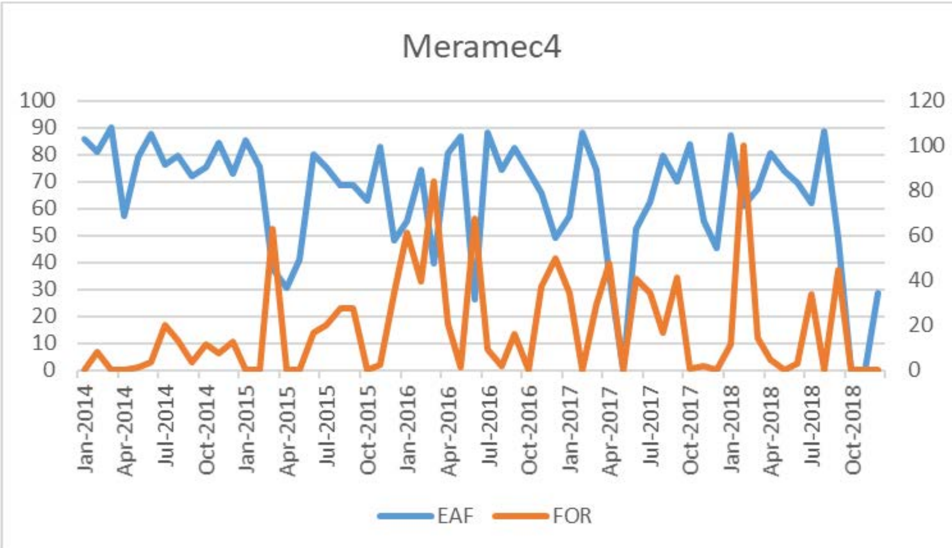

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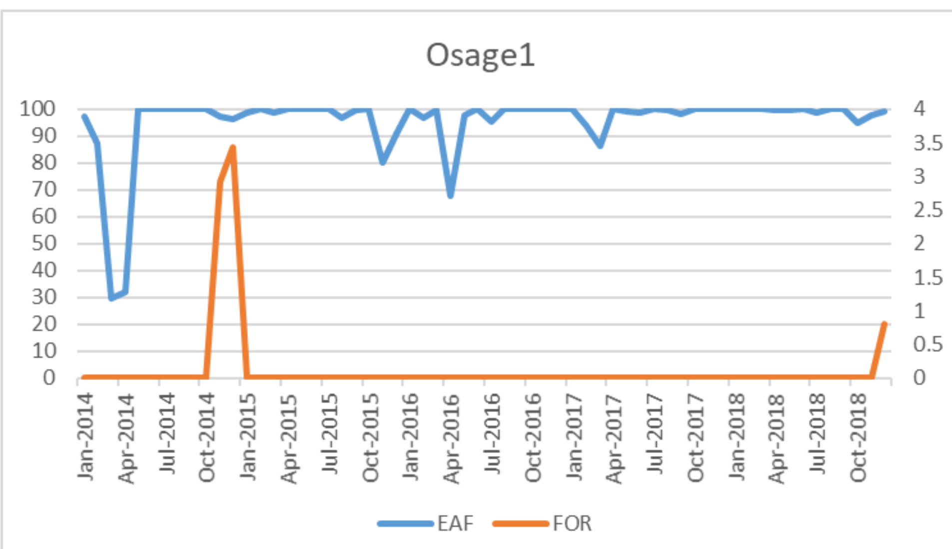

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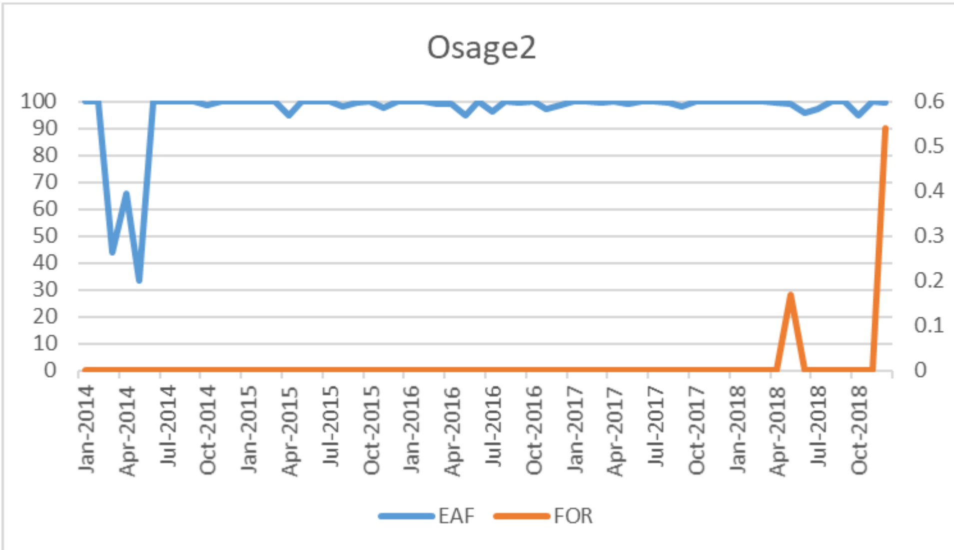

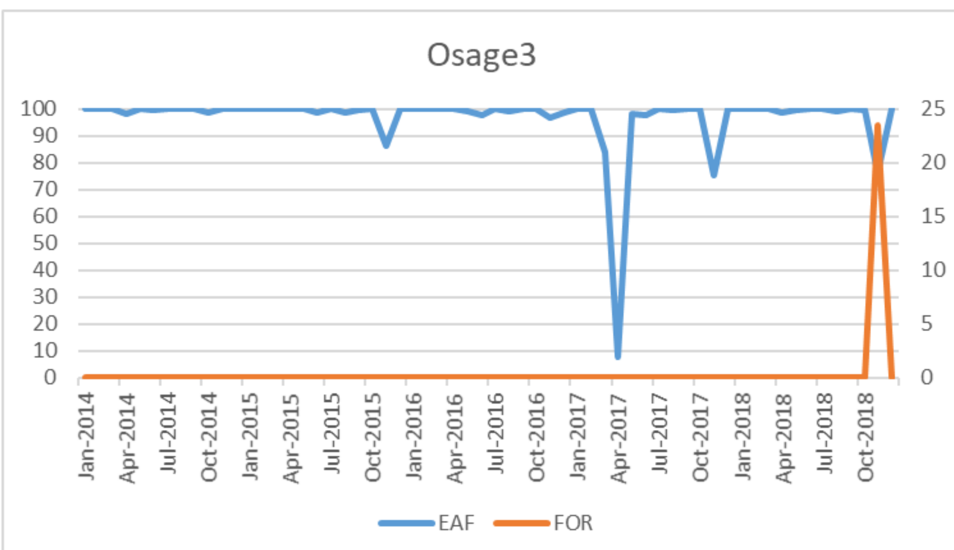

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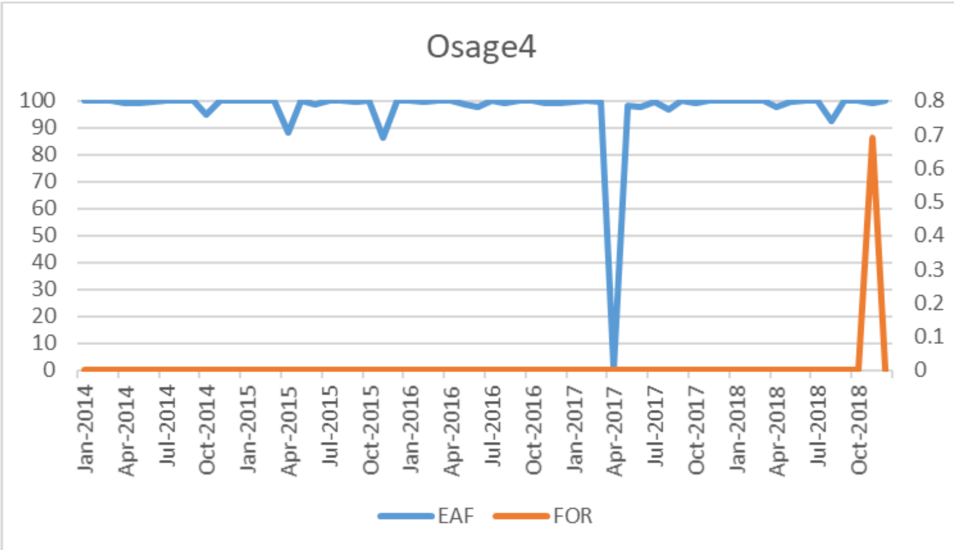

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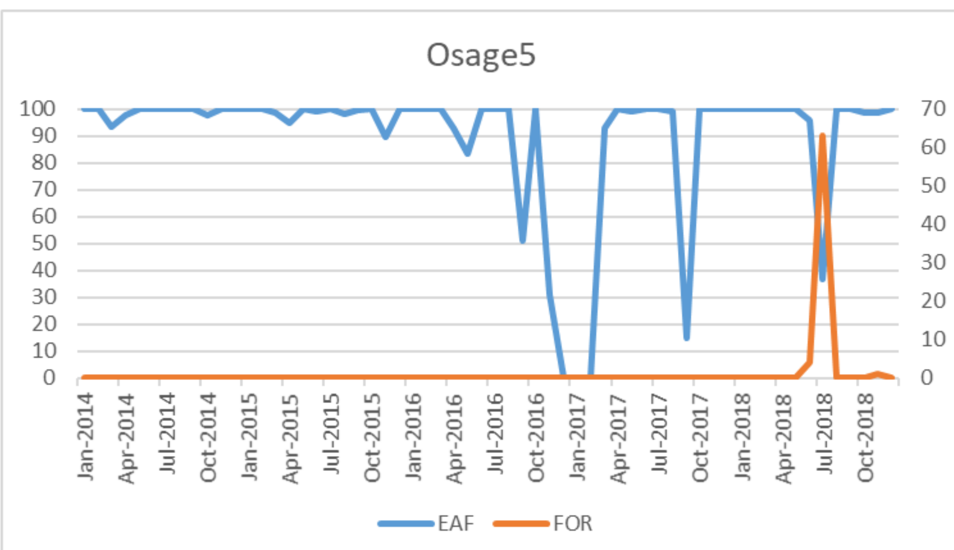

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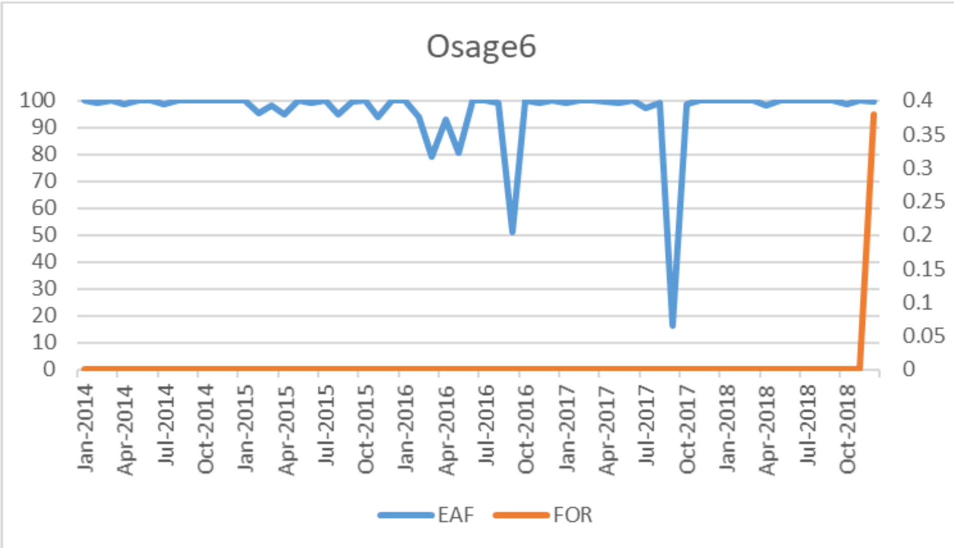

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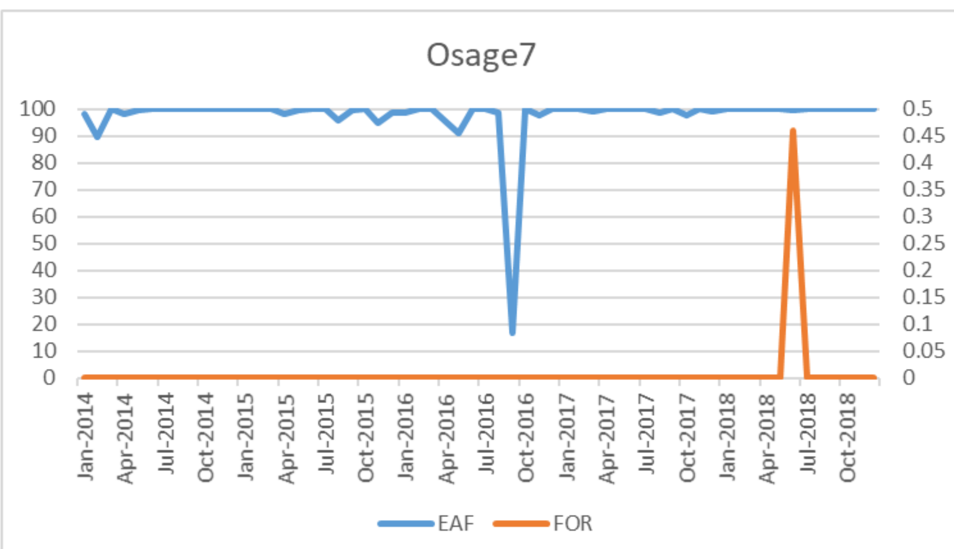

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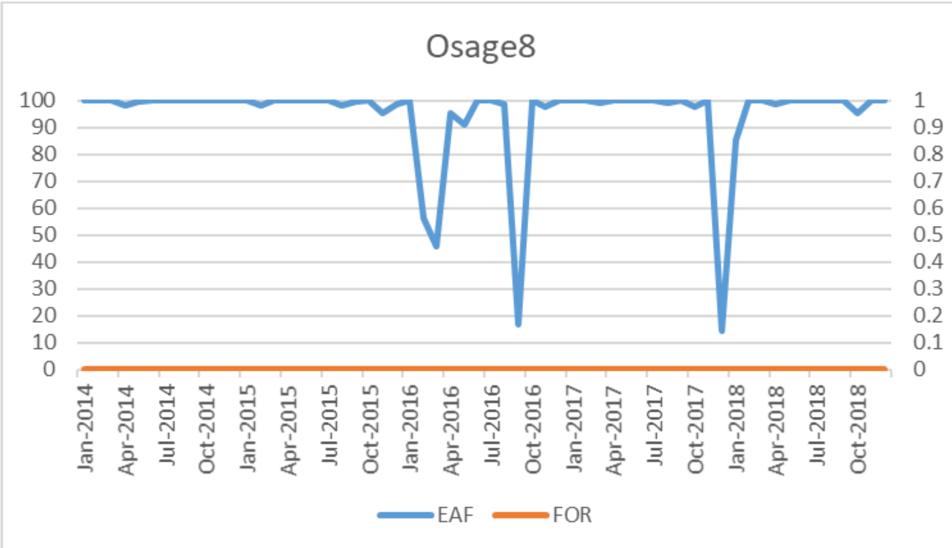
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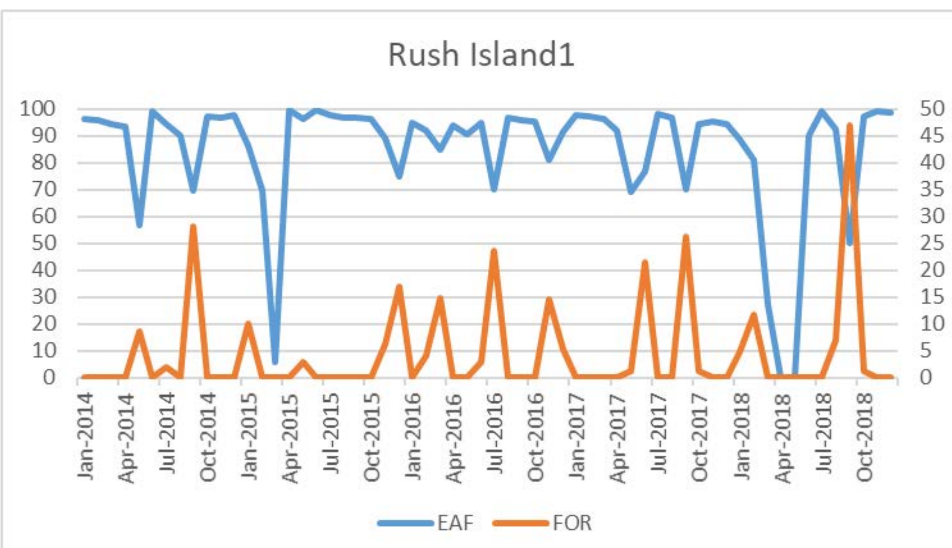
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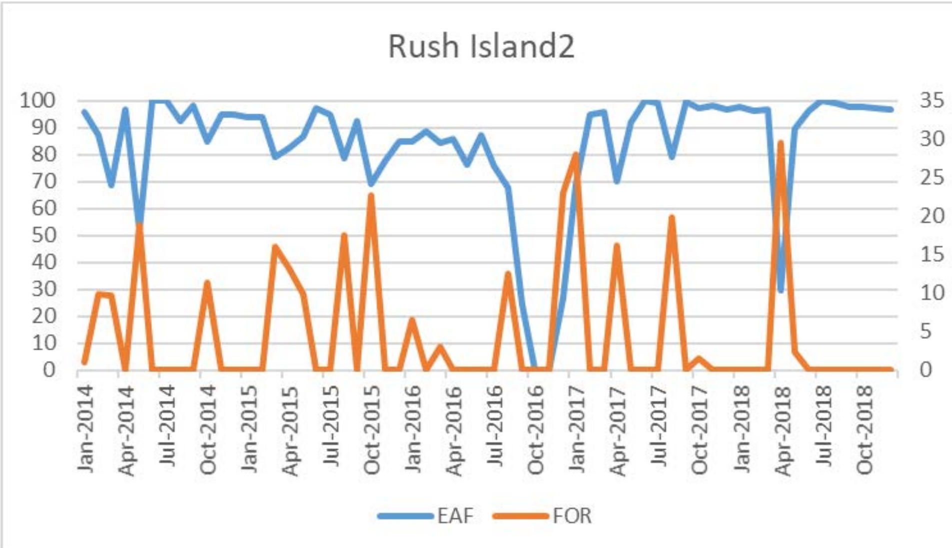

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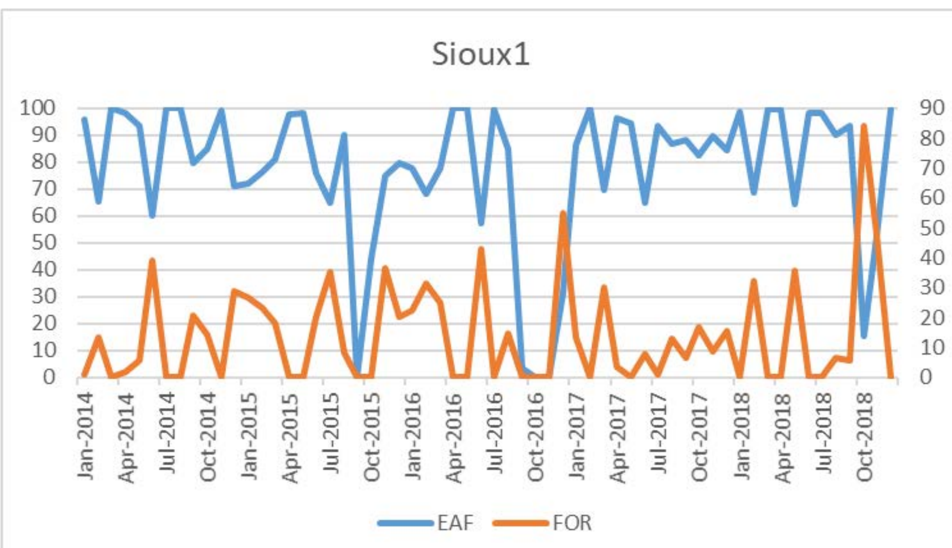

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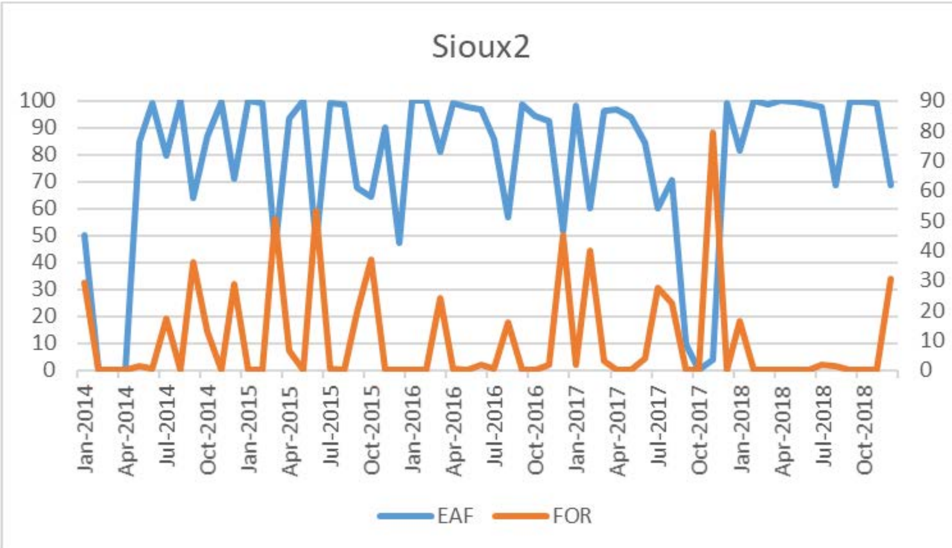

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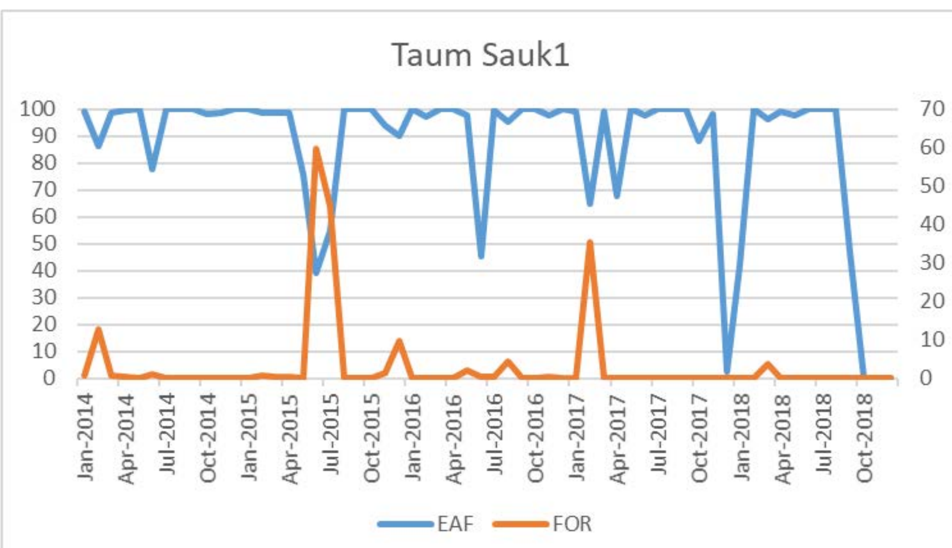

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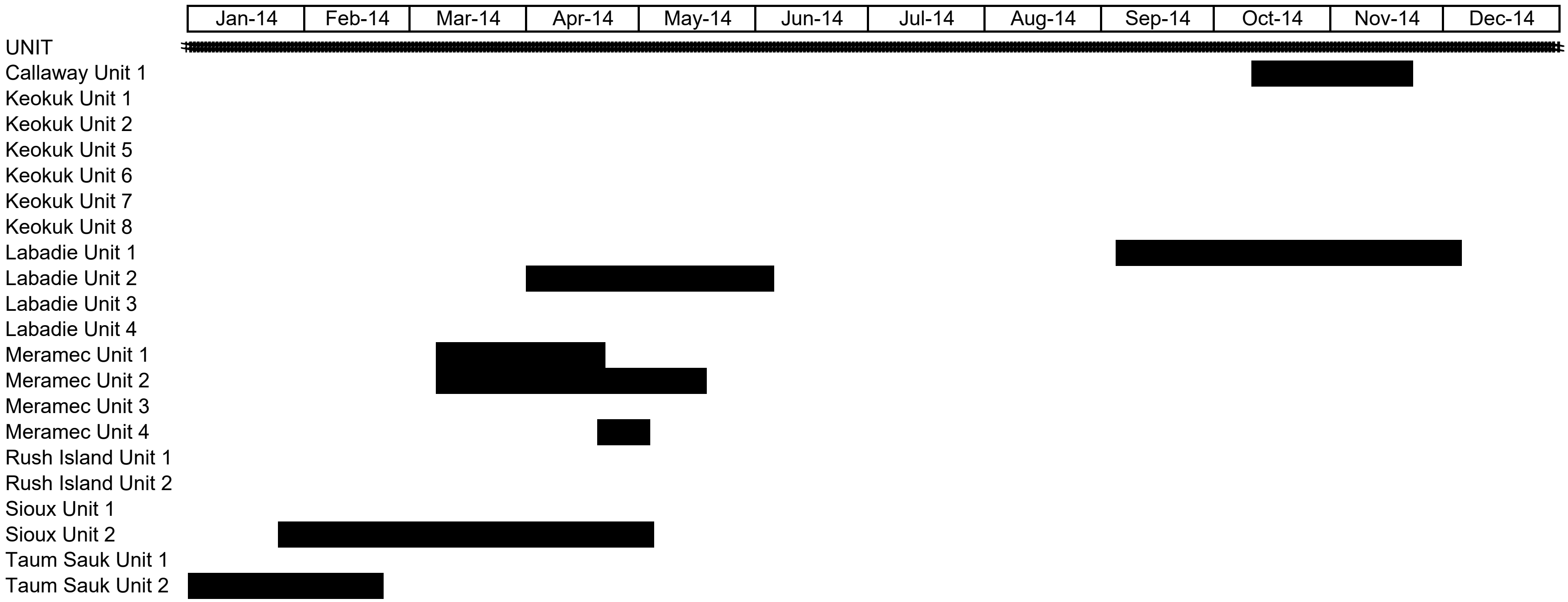
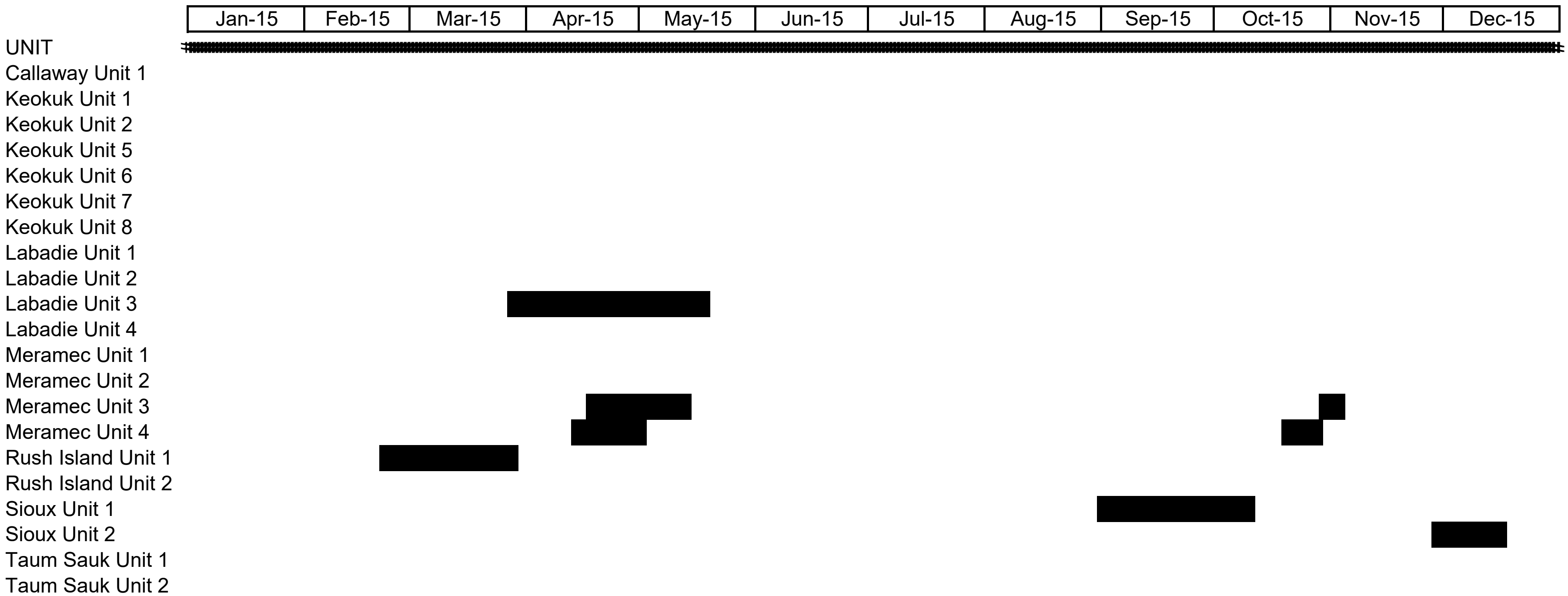


Attachment D



Attachment D

UNIT	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
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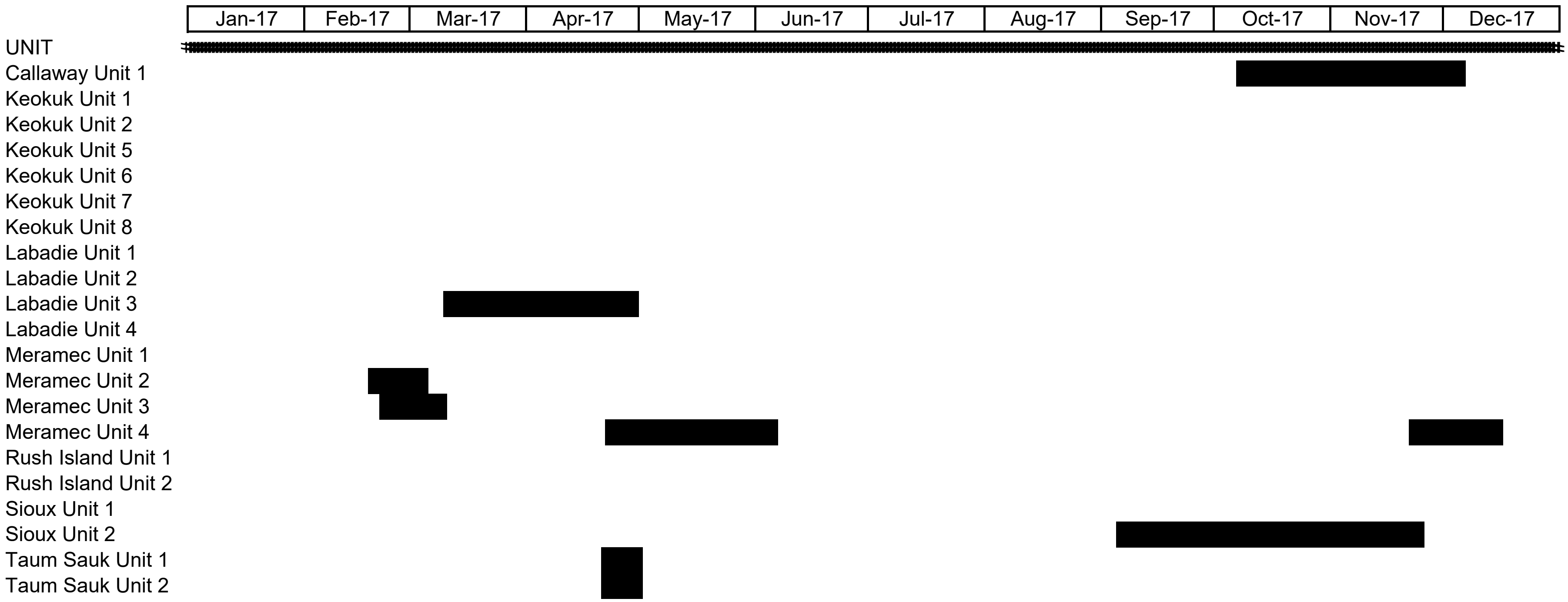
Keokuk Unit 1												
Keokuk Unit 2												
Keokuk Unit 5												
Keokuk Unit 6												
Keokuk Unit 7												
Keokuk Unit 8												
Labadie Unit 1												
Labadie Unit 2					[redacted]							
Labadie Unit 3												
Labadie Unit 4			[redacted]									
Meramec Unit 1				[redacted]								
Meramec Unit 2				[redacted]								
Meramec Unit 3												
Meramec Unit 4												
Rush Island Unit 1												
Rush Island Unit 2									[redacted]			
Sioux Unit 1									[redacted]			
Sioux Unit 2												
Taum Sauk Unit 1						[redacted]						
Taum Sauk Unit 2						[redacted]						

Attachment D



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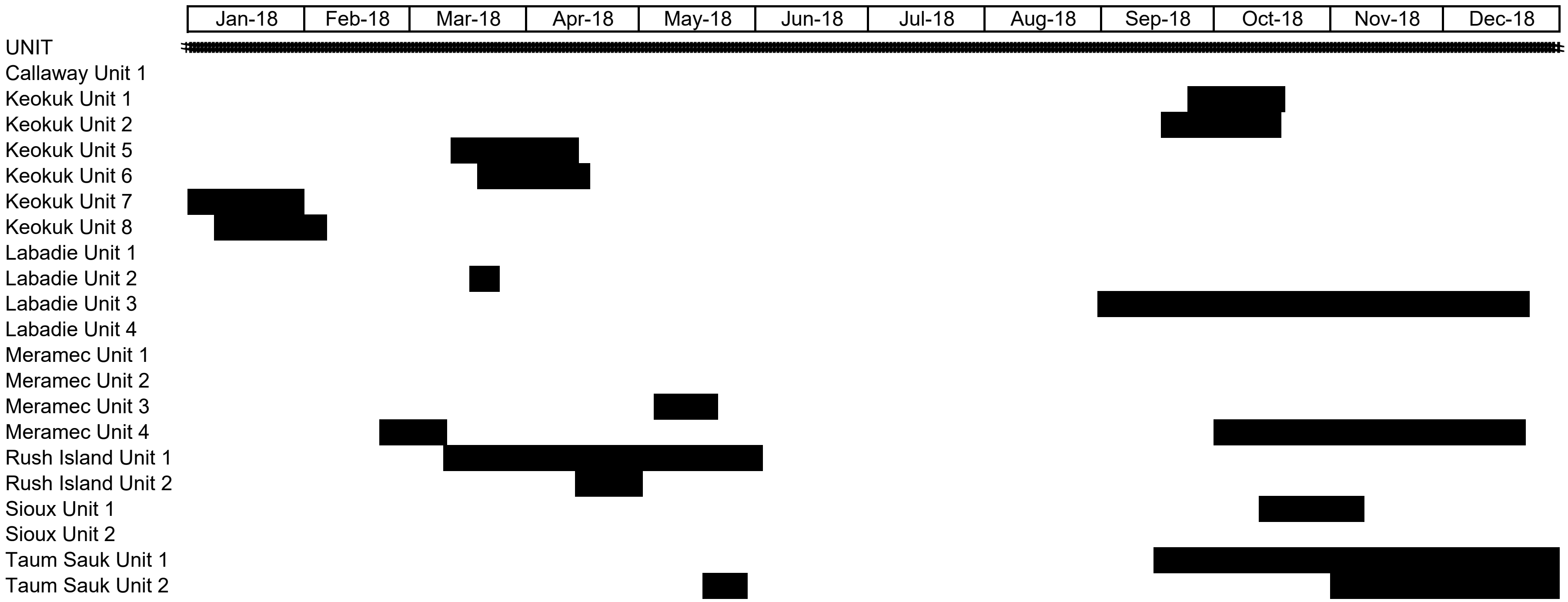
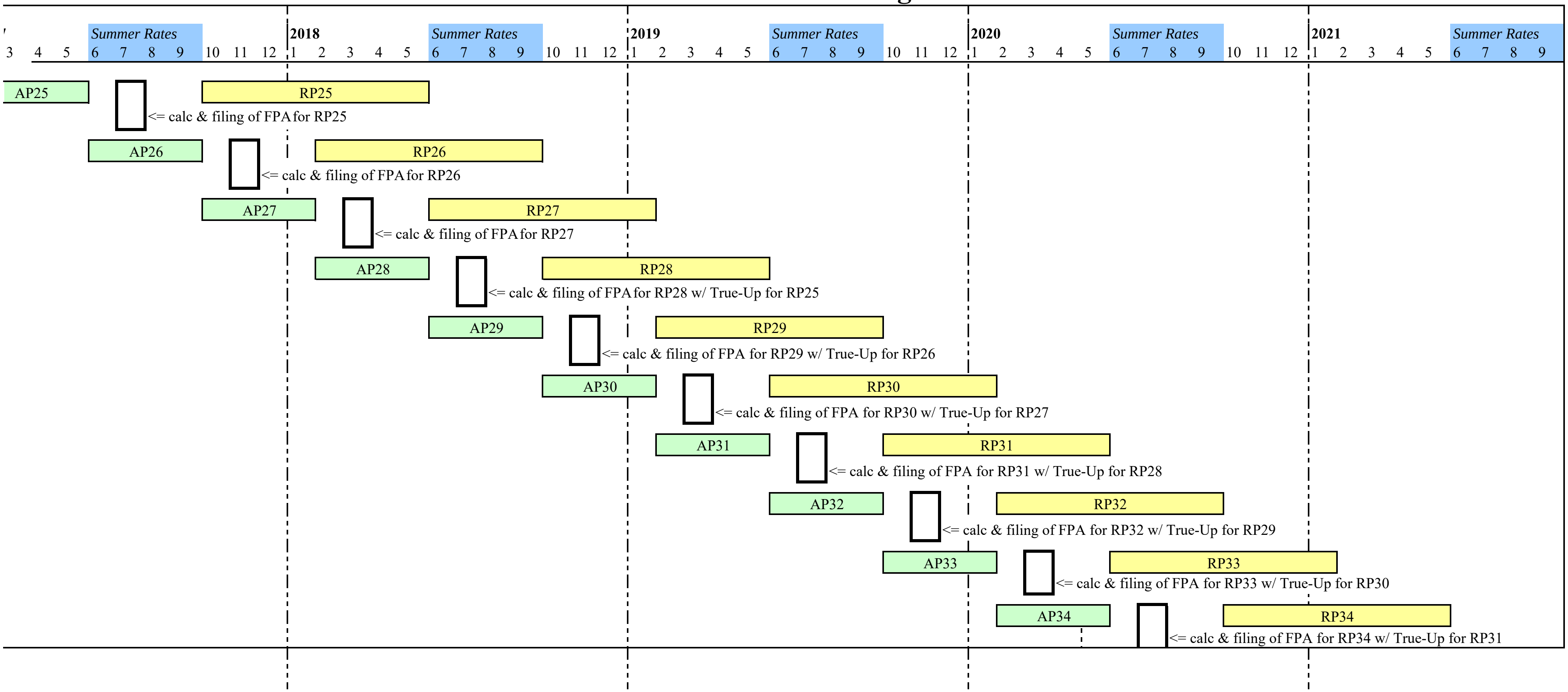


Attachment D

Illustration of AmerenUE's FAC with Seasonal NBFC and Rate Changes



Schedule MLA-D2

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),~~ and ~~12~~11(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 (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~~calendar 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~~day 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:

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

Where:

* ANEC = FC + PP + T + E ± R – OSSR

* FC = Fuel costs and revenues associated with the Company’s generating plants ~~that are listed in Federal Energy Regulatory Commission ("FERC") Account 151 and recorded in FERC Accounts 501 or 547, and all costs and revenues that are recorded in FERC Account 518. These include~~ consisting of the following:

1. For fossil fuel plants:

*A. the following costs and revenues (including applicable taxes) arising from steam plant operations recorded in FERC Account 501: coal commodity, gas, alternative fuels, 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, fuel additive costs included in commodity or transportation costs, oil costs, ash disposal costs and revenues, and expenses resulting from fuel and transportation portfolio optimization activities; ~~and~~

*~~B~~**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 (including applicable taxes) arising from non-steam plant operations recorded in FERC Account 547: 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, but excluding fuel costs related to the Company’s landfill gas generating plant known as Maryland Heights Energy Center; and

*2. The following costs and revenues (including applicable taxes) arising from nuclear plant operations: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

*Indicates Change. **Indicates Addition.

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.)

*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 (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, (b) all charges under Midcontinent Independent 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:

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);

*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.)

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

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.~~T =

*1) One ~~and 71/100~~hundred percent (~~1.71~~100%) of transmission service costs reflected in FERC Account 565 ~~and one and 71/100 percent (1.71%) of transmission revenues reflected in FERC Account 456.1 (~~to either:

a. transmit excess electric power sold to third parties to locations outside of MISO (off-system sales)(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule)or;

b. transmit electric power on a non-MISO system,

**2) One and 65/100 percent (1.65%) of transmission service costs reflected in FERC Account 565 directly attributable to Ameren Missouri's network transmission service (excluding (a) amounts associated with portions of Purchased Power Agreements dedicated to specific customers under the Renewable Choice Program tariff and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule),and

*Indicates Addition. **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.)

~~).~~ *3) One and 65/100 percent (1.65%) of transmission revenues reflected in FERC Account 456.1(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule).

Such transmission service costs and revenues included in Factor ~~PPT~~T 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, 26C, 26D, 37 and 38 or their successors;
- vii. MISO Schedule 33; and
- viii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs and revenues associated with:

- i. Network transmission service;
- ii. Point-to-point transmission service;
- iii. System control and dispatch; and
- iv. Reactive supply and voltage control.

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.

** R = Net insurance recoveries for costs/revenues included in this Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included in this Rider FAC.

* Indicates Change

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

*OSSR = Costs and revenues in FERC Account 447 (excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff and (c) amounts associated with generation assets that began commercial operation after the date BF was determined and that were dedicated to specific customers under the Renewable Choice Program tariff when it began commercial operation) 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.

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.

* 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.)

*Costs and revenues not specifically detailed in Factors FC, PP, T, E, R or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, T 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, T or OSSR for the costs or revenues to be considered specifically detailed in Factors PP, T 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 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, T 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, T 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, T 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, T 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, T 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, T 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, T 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.

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.)

listed in Factors PP, T or OSSR, as the case may be, within 30 days of the 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, T, 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, T, 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 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), plus transmission costs and revenues (constistent with term T), 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.~~01565~~01266 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.~~01536~~01208 per kWh.

*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 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.

Schedule MLA-D3

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~~TUP") 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~~*TUP = 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} + $FAR_{(RP-1)}$~~The lower of (a) PFAR and (b) RAC.

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.

**PFAR = The Preliminary FAR, which is the sum of FAR_{RP} and $FAR_{(RP-1)}$

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}.

*Indicates Change. **Indicates Addition.

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.)

~~*To determine the~~

**RAC = Rate Adjustment Cap: applies to the FAR ~~applicable to~~ rate and shall apply so long as the ~~individual~~rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the baseline rate as determined under Section 393.1655.4 by the 2.85% Compound Annual Growth Rate compounded for the amount of time that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655, and dividing that result by the weighted average voltage adjustment factor 1.0476%.

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

Secondary Voltage Service (VAF_{SEC})	1.~~0549~~0570
Primary Voltage Service (VAF_{PRI})	1.~~0238~~0194
~~Transmission Voltage Service (VAF_{TRAN})~~	~~0.9921~~

** Customers served by the Company under Service Classification No. 11(M), Large Primary Service, shall have their rate capped such that their FARLPS does not exceed RACLPS, where

** RAC_{LPS} = Rate Adjustment Cap Applicable to LPS Class: applies to the FAR rate applicable to customers in the LPS class and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the baseline class average overall rate as determined under Section 393.1655.6 by the 2.00% Compound Annual Growth Rate compounded for the amount of time that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the class average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655.

*Indicates Change. **Indicates Addition.

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.)

*Where the Initial Rate Component for Primary Customers is greater than FAR_{LPS}, 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 Primary Customers– FARLPS) x SLPS) / (SRP – SRP-LPS))

*Where:
SLPS = Estimated Recovery Period LPS kWh sales at the retail meter
SRP-LPS = Estimated Recovery Period LPS 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:

FARSEC = Initial Rate Component For Secondary Customers + (Per kWh FAR Shortfall Adder x VAFSEC)
FARPRI = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAFPRI)

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~~TUP above. Interest on the true-up adjustment will be included in I above.

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.

*Indicates Addition. **Indicates Change.

Schedule MLA-D3

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.)

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;

UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6 Original SHEET NO. ~~74.10~~71.13

CANCELLING MO.P.S.C. SCHEDULE NO. SHEET NO.

APPLYING TO MISSOURI SERVICE AREA

***MISO Transmission 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~~Schedules 26-C & 26-D - (TMEP Cost Recovery);
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 Schedule 33 (Black Start Service);

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;
RT Virtual Energy Amount;

* Indicates ~~Addition~~Change.

~~Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2016-0179.~~

DATE OF ISSUE ~~March 8, 2017~~July 3, 2019 DATE EFFECTIVE ~~April 1, 2017~~August 2, 2019

ISSUED BY Michael Moehn President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

Schedule MLA-D3

~~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 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.)

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;
Reactive Services;

PJM Charge Types Which Appear On The Settlement Statements Represent Administrative 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;

*** *SPP Market Settlement Charge Types**

DA Asset Energy Amount;
DA Non-Asset Energy Amount;
DA Make-Whole Payment Distribution;
DA Make-Whole Payment;;
DA Virtual Energy;
DA Virtual Energy Transaction Fee;
DA Demand Reduction Amount;
DA Demand Reduction Distribution Amount;
DA GFA Carve-Out Daily Amount;
DA GFA Carve-Out Monthly Amount;
DA GFA Carve-Out Yearly Amount;
GFA Carve Out Distribution Daily Amount;
GFA Carve Out Distribution Monthly Amount;
GFA Carve Out Distribution Yearly Amount;
RT Asset Energy Amount
RT Over Collected Losse;s Distribution;
RT Miscellaneous Amount;
RT Non-Asset Energy;
RT Revenue Neutrality Uplift;
RT Joint Operating Agreement;
RUC Make Whole Payment Distribution;
RUC Make Whole Payment;
RT Virtual Energy Amount;
RT Demand Reduction Amount;
RT Demand Reduction Distribution Amount;
Transmission Congestion Rights Daily Uplift;
Transmission Congestion Rights Monthly Payback;
Transmission Congestion Rights Auction Transaction;
Transmission Congestion Rights Annual Payback;
Transmission Congestion Rights Funding;
Auction Revenue Rights Annual Closeout;
Transmission Congestion Rights Annual Closeout
Auction Revenue Rights Uplift
Auction Revenue Rights Monthly Payback
Auction Revenue Rights Annual Payback
DA Regulation Up
DA Regulation Down
DA Regulation Up Distribution
DA Regulation Down Distribution
DA Spinning Reserve
DA Spinning Reserve Distribution
DA Supplemental Reserve
DA Supplemental Reserve Distribution
RT Regulation Up
RT Regulation Up Distribution
RT Regulation Down
RT Regulation Down Distribution
RT Regulation Out of Merit
RT Spinning Reserve Amount
RT Supplemental Reserve Amount
RT Spinning Reserve Cost Distribution Amount
RT Supplemental Reserve Distribution Amount
RT Regulation Non-Performance
RT Regulation Non-Performance Distribution
RT Regulation Deployment Adjustment;
RT Regulation Deployment Adjustment;
RT Contingency Reserve Deployment Failure Distribution;
RT Reserve Sharing Group;
RT Reserve Sharing Group Distribution;
RT Pseudo-Tie Congestion Amount;
RT Pseudo-Tie Losses Amount;
RT Unused Regulation -Up Mileage Make Whole Payment;

Auction Revenue Rights Funding; RT Unused Regulation -Down Mileage Make Whole Payment;

** **SPP Transmission Service Charge Types**

Schedule 1 – Scheduling, System Control & Dispatch Service;
Schedule 2 – Reactive Voltage;
Schedule 7 – Zonal Firm Point-to-Point;
Schedule 8 – Zonal Non-Firm Point-to-Point;
Schedule 11 – Base Plan Zonal and Regional;

** **SPP charge types representing administrative charges specifically excluded from the FAC**

Transmission Schedule 1A – Tariff Administrative Fee;
Transmission Schedule 12 – FERC Assessment;

** Indicates Addition.

UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6 ~~Original~~ SHEET NO. ~~74.~~1371.17

CANCELLING MO.P.S.C. SCHEDULE NO. SHEET NO.

APPLYING TO MISSOURI SERVICE AREA

RIDER FAC

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

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

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending:

* 1.	Actual Net Energy Cost = (ANEC) (FC+PP+E~~±~~+R+T-OSSR)		$
2.	(B) = (BF x S_{AP})	-	$
	2.1 Base Factor (BF)		$/kWh
	2.2 Accumulation Period Sales (S_{AP})		kWh
3.	Total Company Fuel and Purchased Power Difference	=	$
	3.1 Customer Responsibility	x	95%
4.	Fuel and Purchased Power Amount to be Recovered	=	$
	4.1 Interest (I)	-	$
	*4.2 True-Up Amount (~~T~~TUP)	+	$
	4.3 Prudence Adjustment Amount (P)	±	$
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$0.00000/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$0.00000/kWh
** 9.	Preliminary Fuel Adjustment Rate (PFAR)	=	$0.00000/kWh
**10.	Rate Adjustment Cap (RAC)	=	$0.00000/kWh
*11.	Fuel Adjustment Rate (FAR~~)~~ ~~=~~, lesser of PFAR and RAC)	=	$0.00000/kWh

~~10~~**Initial Rate Component for the Individual Service Classifications**

*12.	Secondary Voltage Adjustment Factor (VAF_{SEC})	1.~~05490~~0570
~~11~~ 13.	Initial Rate Component for Secondary Customers	$0.00000/kWh
~~12~~*14.	Primary Voltage Adjustment Factor (VAF_{PRI})	1.~~02380~~0194
~~13~~15.	Initial Rate Component for Primary Customers	$0.00000/kWh

~~14. Transmission Voltage Adjustment Factor (VAF_{TRAN}) 0.9921~~

~~15. Initial Rate Component for Transmission~~**FAR Applicable to the Individual Service Classifications**

16. RAC_{LPS}	=	$0.00000/kWh
17. FAR for Large Primary Service (FARLPS, lesser of 15 and 16)	=	$0.00000/kWh
18. Difference (Line 15 – Line 17)	=	$0.00000/kWh
19. Estimated Recovery Period Metered Sales for LPS (SLPS)		kWh
20. FAR Shortfall Adder (Line 18 x Line 19)		$

~~Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2016-0179.~~

DATE OF ISSUE ~~March 8, 2017~~July 3, 2019 DATE EFFECTIVE ~~April 1, 2017~~August 2, 2019

ISSUED BY Michael Moehn President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

Schedule MLA-D3

21. Per kWh FAR Shortfall Adder = $0.00000/kWh
(Line 20 / (Line 6 – SRP-LPS))

22. FAR for Secondary Customers (FARSEC) = $0.00000/kWh
~~.~~(Line 13 + (Line 21 x Line 12))

23. FAR for Primary Customers (FARPRI) = $0.00000/kWh
(Line 15 + (Line 21 x Line 14))

*Indicates Change. **Indicates Addition.

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 Decrease Its Revenues for Electric Service.	)))	File No. ER-2019-0335

AFFIDAVIT OF MARCI L. ALTHOFF

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

Marci L. Althoff, being first duly sworn on her oath, states:

1. My name is Marci L. Althoff. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services as a Manager, Finance Transformation.

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 14 pages and Schedule(s) MLA-D1 to MLA-D3, 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.

Marci L. Althoff

Marci L. Althoff

Subscribed and sworn to before me this 27th day of June, 2019.

Geri A. Best

Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2022
Commission Number: 14839811