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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2021-0240

DIRECT TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
March, 2021

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DIRECT TESTIMONY

OF

ANDREW MEYER

FILE NO. ER-2021-0240

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

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

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

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

Q. Please describe your employment and educational background.

A. I joined Ameren's independent marketing affiliate, Ameren Energy Inc., in 1999. Ameren Missouri assumed this corporate function in 2004. I have worked in several different capacities on the trading floor and in Regional Transmission Organization ("RTO") stakeholder relations. My trading responsibilities included long-term energy and capacity position management, financial hedging, congestion management, and real-time trading and scheduling. Since 2009, I have progressed through several managerial roles. These roles all included responsibility for wholesale energy marketing for Ameren Missouri's generation.

Over time, my role has expanded on multiple occasions and now includes Gas Supply, RTO Real-Time Operations, Fossil Fuel Procurement & Logistics, Nuclear Fuel Procurement, Generation Performance Monitoring, and NERC[1] Compliance.

I earned Bachelor of Science degrees in Business Administration (Management Emphasis) and Agricultural Economics from the University of Missouri – Columbia. I was employed by Continental Grain Co. prior to joining Ameren.

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

A. The purpose of my testimony is to sponsor the continuation of Ameren Missouri's Fuel Adjustment Clause ("FAC"), including providing the minimum filing requirements prescribed by the Commission's FAC rules and 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.

I will also discuss the establishment of the level of off-system sales revenues ("OSSR"),[2] net of the normalized capacity component of purchased power expense, to be included in the cost of service utilized for the purpose of setting Ameren Missouri's rates.

The third purpose of my testimony is to demonstrate the continued volatility and uncertainty of ANEC and of the market drivers which impact the costs and revenues tracked in the FAC. These drivers include commodity prices and volumetric fluctuations in the Company's commodity and transportation requirements.

[1] North American Electric Reliability Corporation.
[2] Factor "OSSR" in the Company's FAC tariff sheets which in totality are called "Rider FAC."

II. FUEL ADJUSTMENT CLAUSE CONTINUATION

Q. Is the Company requesting to continue its 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 six rate cases support its continuation now.

Q. When was the first FAC approved for the Company?

A. The FAC was first approved in late January 2009 in File No. ER-2008-0318, and became effective March 1, 2009. The basic structure and operation remains essentially the same now as it was when it was first approved, although there have been some changes in its details, primarily to add more detail to the tariff sheets. The FAC rate (defined as the "Fuel Adjustment Rate" or "FAR" in the tariff), 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 April 1, 2021 to reflect changes in ANEC as compared to NBEC for the accumulation period of October 2021 to January 2021. Counting that filing, since the FAC's inception, 35 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 April 1, 2021, the recovery period will be the eight calendar months of June 2021 through January 2022. Interest is applied to the sums recovered or returned. The FAC rates currently in effect were established starting February 1, 2021.

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

A. ANEC have continued to decrease. ANEC for the 12 months ending with the true-up cut-off date in File No. ER-2016-0179 (December 31, 2016) were approximately $610 million. In File No. ER-2019-0335, ANEC for the 12 months ending with the true-up cutoff date of December 31, 2019 were approximately $479 million, a decrease of approximately 7% from the same 12 months of 2018. ANEC for the proposed test year in this case (the 12-months ending December 31, 2020) were approximately $447 million, which is an additional 7% decrease from 2019 levels and an approximately 15% reduction from 2018 levels.

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 20 CSR 4240-20.090, in particular Section 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 AMM-D1.

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

A. Ameren Missouri's FAC should be continued for several reasons, including: 1) that all of the factors the Commission has generally considered in evaluating FACs favor continuation of the FAC; 2) that the FAC is reasonably designed to provide the Company a sufficient opportunity to earn a fair return; 3) that 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) that 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) that 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.

When the question of whether the FAC should be continued has been litigated (on several occasions, including in the Company's last fully litigated electric rate case, File No. ER-2014-0258), the Commission has consistently recognized that all of these reasons continued to demonstrate the appropriateness of the Company's FAC.[3] The Company's FAC was also continued in the last two general rate proceedings by agreement of the settling parties, and each of those agreements was approved by the Commission.

Q. Please elaborate on why the considerations that have supported continuation of the Company's FAC continue to do so.

A. To provide some context, the Commission initially approved Ameren Missouri's FAC based in part upon its conclusions about three factors it has considered when reviewing FAC requests. Specifically, these factors suggest that the changes in costs or revenues that would be included in the FAC should be:

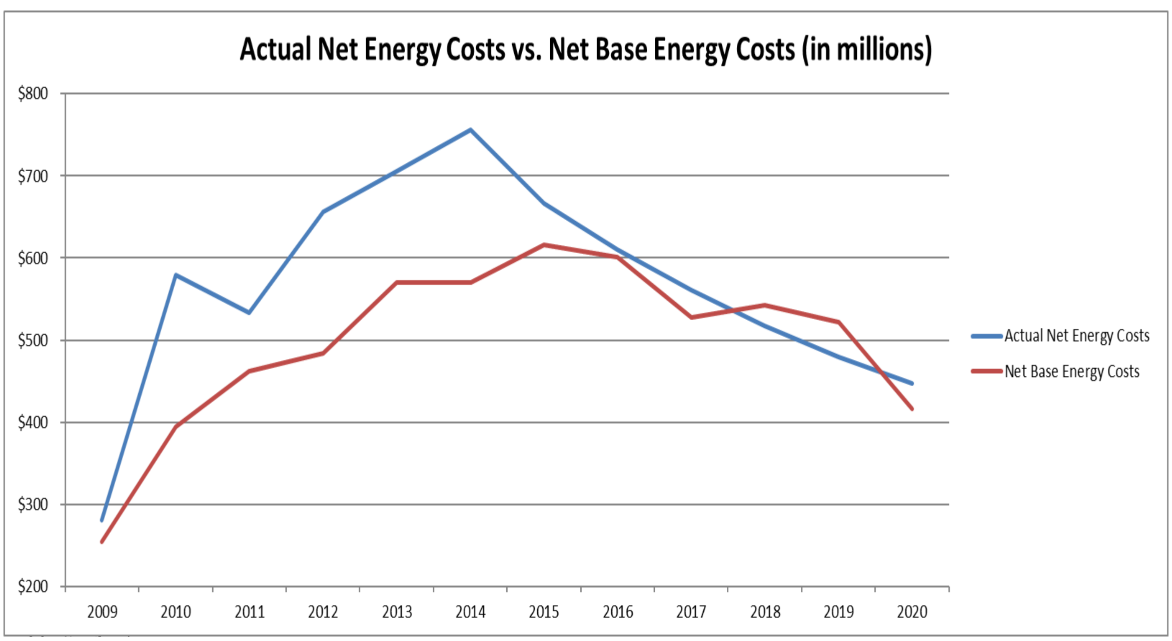
1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. Beyond the control of management, where the utility has little influence over experienced revenue or cost levels; and

[3] *Report and Order*, File No. ER-2014-0258, pp. 102-104, issued April 29, 2015.

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

The Company's fuel and purchased power costs continue to be substantial. Those costs (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 42% of its total O&M costs in 2020. 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 $447 million as of the end of 2020. 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.[4] The changes in ANEC through the end of 2020 are depicted in the Figure 1 below:

Figure 1:



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 seven rate cases (with this being the eighth) 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.[5]

Q. Do volatility and uncertainty continue to exist?

A. Yes. In this regard, nothing has changed regarding the continuing volatility of the Company's ANEC, which is clearly shown by the substantial changes (up and down) in the Company's ANEC over the past several years. As Figure 1 above shows, ANEC has increased since the FAC was first established. Across these years there have been periods when the ANEC has moved both up and down in a year-over-year comparison, demonstrating the volatility and uncertainty of the Company's fuel and purchased power costs net of off-system sales, including transportation. It also continues to be true that the national and international markets that set the prices for fuel and power continue to be volatile.

[5] The Commission has recognized this for years: *Report and Order*, Case No. ER-2008-0318, p. 63, issued January 27, 2009 ("[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, issued April 29, 2015 ("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."); *Report and Order,* Case No. ER-2019-0335, p. 9, issued April 29, 2020 ("Fuel costs are volatile and electric utilities do not have complete control over those fuel costs. In general, Ameren Missouri's net energy costs are set by markets for energy and fuel that are largely beyond Ameren Missouri's control" (footnotes omitted)).

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 have seen on a number of occasions, 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.

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, it has very little control over the volumetric components of ANEC. For example, as I will discuss in greater detail later in this 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.

Q. Is the volatility and uncertainty of ANEC also demonstrated by a comparison to Company forecasts?

A. Yes. Chart 1 and Chart 2 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.

Chart 1

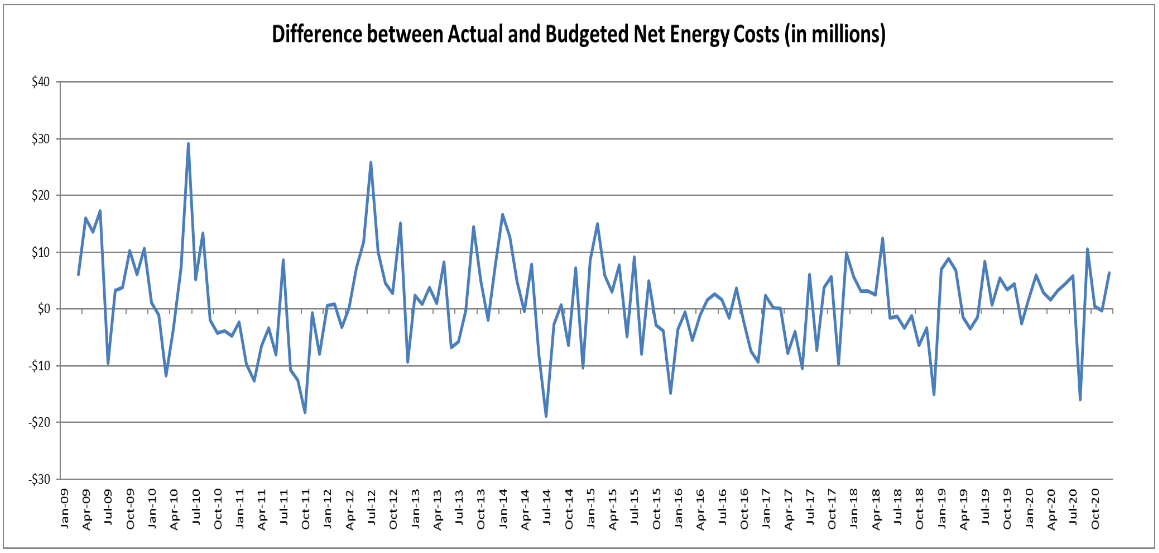
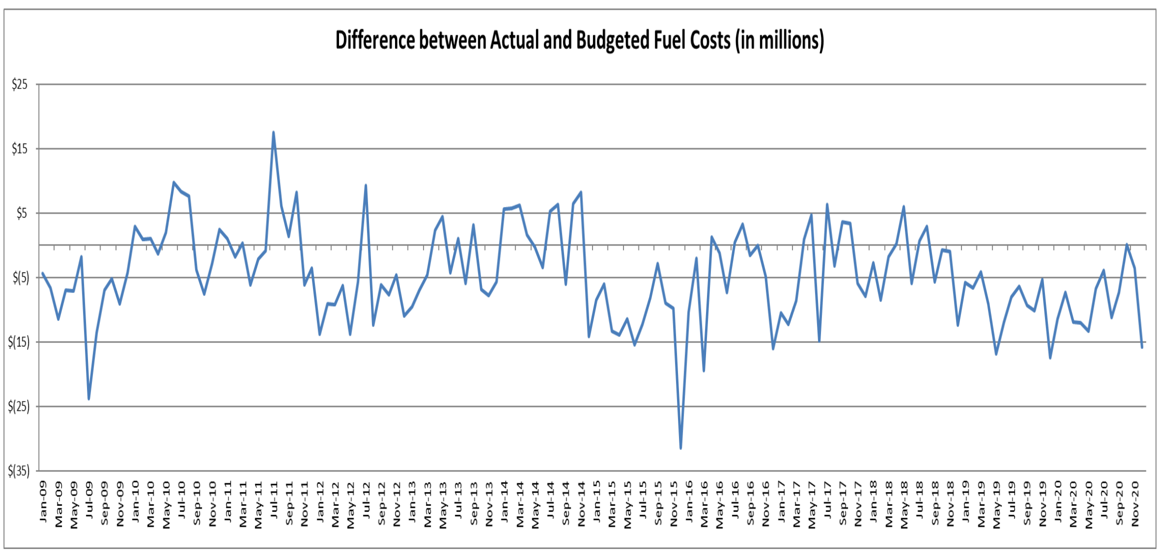


Chart 2 shows the same thing for the fuel cost component of ANEC:



These charts clearly show the volatility – both up and down. That in actual practice we see tens of millions of dollars in differences between what we budget and what we actually experience demonstrates that these costs are volatile and uncertain.

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. I will discuss the volatility of market factors impacting FAC components later.

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 AMM-D2, it will take at least 12 months between the time when changes in ANEC occur and when those changes are fully[6] 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. Putting aside the three factors considered by the Commission when the FAC was originally approved (magnitude/control/volatility-uncertainty), 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 other electric utilities in Missouri).

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

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,"[7] 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.[8] The facts that supported those findings have not changed.

Q. Has the Company recommended changes to Rider FAC tariff as filed in this case?

A. Some minor ones, yes. First, we are recommending language relating to the Company's plans to offer a different renewable subscriber program than its existing Renewable Choice program, which was first addressed in its pending IRP docket. Conceptually, this change (which appears in a few places in Rider FAC) is the same as the existing language that applies to Renewable Choice, which is designed to keep the impact of assets dedicated to subscriber programs outside the FAC. Second, 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 for minor changes to Regional Transmission Organization charge types since the last rate review. There is only one additional charge type (in the SPP market), RT Contingency Reserve Deployment Failure, which existed as of the time of the Company's last rate review but was inadvertently omitted from the FAC tariff filed and approved at that time.

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[7] *Report and Order*, File No. ER-2010-0036, p. 78, issued May 28, 2010.
[8] *Report and Order,* File No. ER-2014-0258, p. 103, issued April 29, 2015 ("… 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.").

The charge type can reflect charges or revenues, but to-date no charges or revenues have been assessed/paid to the Company. This charge type is essentially the same as the MISO RT Contingency Deployment Failure charge type which has been reflected in the FAC for some time.

Third, changes were made to the FAC's voltage adjustment factors ("VAF") to implement the agreements reflected in paragraph 35 of the Corrected Non-Unanimous Stipulation and Agreement approved by the Commission in File No. ER-2019-0335, Ameren Missouri's last rate case. Historically, the only VAF differentiation was between customers served at primary versus secondary voltages. However, not all primary voltage customers are served at a single voltage. As noted, in settlement of File No. ER-2019-0335, the Company agreed to add further differentiation within the primary voltage VAFs instead of using an average line loss rate to develop a single VAF applicable to all primary voltage customers. Consequently, we are proposing three primary service VAFs, in addition to the single secondary VAF, for a total of four.[9]

Finally, we have updated Base Factor ("BF") amounts using updated NBEC figures. All these changes are reflected in Schedule AMM-D3, which is an exemplar FAC tariff attached to my testimony which shows changes tracked against the FAC tariff currently in effect. None of the changes fundamentally alter the components in the FAC as compared to what those components have generally been since the FAC was first approved in 2009.

[9] Calculation of the VAFs was completed by Company witness Michael Harding, as reflected in his workpapers.

Q. Has the Company also updated the B used to calculate the BF[10] in the FAC tariff to reflect the current level of B?

A. Yes. When base rates are reset 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 1.259 cents per kilowatt-hour ("kWh") for the summer and 1.167 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 1.149 cents per kWh for the summer and 1.036 cents per kWh for the winter. The calculation of the NBEC that underlies these BF values is addressed in detail in the direct testimony of Ameren Missouri witness Mitchell Lansford.

Q. Has the Company recommended any changes to the FAC sharing percentage in this case?

A. No. Even though most utilities in other states with FACs do not have a sharing mechanism, the Company is recommending to continue the 95/5 sharing ratio that has been in place since the Company first received a FAC.

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

Nothing has changed over the past year, since the Commission once again reaffirmed the appropriateness of the 95/5 sharing mechanism, that would suggest a change in the sharing mechanism is warranted: "(t)he Commission has found on several occasions, that the 95/5 sharing ratio provides Ameren Missouri sufficient incentive to operate at optimal efficiency and still provides an opportunity for Ameren Missouri to earn a fair return on its investment."[11]

Q. Would the Company's incentive to efficiently manage net energy costs change if the sharing percentage were eliminated or changed to increase Company exposure?

A. No. The Company has more than enough incentive to efficiently manage its net energy costs, such as prudence reviews and the possibility that the FAC could be discontinued completely.

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

Q. What is the meaning of "net off-system sales revenue" in the context of this testimony?

A. In the context of this proceeding, I use the term “net off-system sales revenue” in reference to the revenues and costs from transactions resulting from Ameren Missouri’s trading activities after netting out the costs and revenues associated with purchasing energy from the MISO market to meet the Company’s load requirements.

[11] *Report and Order,* File No. ER-2019-0335, p. 12, issued April 29, 2020.

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

A. I determined that the level of net off-system sales revenues that should be included in Ameren Missouri's revenue requirement and used to set NBEC in the FAC is approximately $320.2 million per year. This total is comprised of the following components, each of which I address in more detail later in this testimony:

1) $282.1 million of net energy sales revenues;

2) $23.8 million of gross capacity sales revenues;

3) $5.3 million of ancillary services revenues;

4) $1.4 million of real-time RSG MWP[12] margins; and

5) $7.6 million of other physical bilateral and swap margins.

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

A. I determined that the level of the capacity component of purchased power expense that should be included in Ameren Missouri's revenue requirement and used to set NBEC in the FAC is $16.8 million.

[12] Real-time revenue sufficiency guarantee make-whole payments.

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

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

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

A. PowerSIMM simulates Ameren Missouri's interactions with the market. Ameren Missouri is a market participant within the MISO markets.

The Company purchases energy for its entire load from the MISO market and it separately sells all the megawatt-hours ("MWhs") generated by its generating units to the MISO market. In accordance with FERC requirements, however, these amounts are netted against each other for each hour.[13] This netting results in the recording of either a net off-system sale or a net power purchase for that hour depending on whether the volume of total sales exceeds the volume of total purchases (net off-system sale) or the volume of total sales is less than the volume of total purchases (net power purchase). The results of the Company's modeling reflect netted amounts for both off-system sales and purchased power.

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

[13] The only exception to this is that the energy from the Atchison wind facility is sold into the Southwest Power Pool ("SPP") market since that facility is connected to the transmission system under SPP's functional control.

The simulated net off-system energy sales revenues are determined based on the hourly market price for the MWhs reported as net sales. The model effectively assumes that the dispatch of Ameren Missouri's generation is "perfect," meaning it assumes that available generation units will always operate at the optimal economic level in each hour.[14]

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

A. Consistent with the approach used in the last several base rate proceedings, the price assumption used to model dispatch was the average hourly energy prices for the 36-month period ending September 30, 2021. These prices averaged $23.50 per MWh, on an around-the-clock basis. The energy prices for the period of October 1, 2018 through December 31, 2020 are the actual generation weighted average day-ahead locational marginal prices ("LMPs") in the MISO energy market for Ameren Missouri generating units. Consistent with past practice, the energy prices for the remaining months are basis-adjusted forward energy prices, which serve as a reasonable proxy until they are replaced with actual generation weighted energy prices as part of the true-up in this case.

[14] As noted in Mr. Peter's direct testimony, the Company has adopted Staff's approach from Ameren Missouri's last two electric rate proceedings, File Nos. ER-2016-0179 and ER-2019-0335, for normalizing the generation output for the Keokuk and Osage Energy Centers.

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

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

Q. What is the level of gross capacity sales revenues and gross capacity purchase costs that is appropriate to include in total net off-system sales?

A. I have determined that $23.8 million of gross capacity sales revenues and $16.8 million of gross capacity purchase costs are the appropriate amounts to include in the determination of NBEC. These values represent the average annual sales revenues and purchase costs for the last three MISO Planning Years ("PY"),[15] which cover the period of June 1, 2018 through May 31, 2021. The sales value includes both bilateral capacity sales revenue and MISO Planning Resource Auction sales revenue. This is the same valuation methodology for capacity sales revenues and purchase costs the Company recommended in File No. ER-2019-0335.

[15] PY 2018/19, PY2019/20, and PY2020/21. Planning years run from June 1 to May 31.

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

A. Consistent with past practice, Ameren Missouri self-schedules its capacity obligation in MISO's annual capacity auction. In doing so, Ameren Missouri offers its resources, up to the megawatt ("MW") amount needed to meet its load obligations, at $0.00/MW-day, ensuring that at least that amount of its resources will clear (i.e., be sold) in the capacity auction.

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

A. Based upon actual test year values, I have concluded the level of annual ancillary services revenues to include in total net off-system sales is $5.3 million. As was done in the prior case, we intend to true-up this level through the true-up cutoff date based upon data for the twelve-month period ending September 30, 2021.

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

A. $1.4 million. I determined this level of margin by multiplying the $2.8 million of RT RSG MWP in the test year by 52%, which was the ratio of the RT RSG MWP margin to total real-time RSG MWPs from the true-up period in File No. ER-2019-0335. Consistent with past practice, we intend to update this percentage as part of the true-up process to reflect actual amounts during the twelve months ending with the last day of the true-up period.

Q. What level of physical bilateral trading contract and swap margins did you determine was appropriate to include in net off-system sales?

A. $7.6 million.

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

A. Physical bilateral transactions and financial swaps are hedging mechanisms used to mitigate some of the volatility in OSSR, but they do not replace the off-system energy sales themselves. Physical bilateral transactions and financial swaps margins of $1.2 million and $6.4 million, respectively, should be utilized for this component of net off-system sales revenues. These amounts will also be trued-up.

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

A. The margin calculation for physical bilateral transactions and financial swaps is based on the difference between the fixed sale price and the floating index settlement price. This is the same approach utilized by the parties in the Company's last rate proceeding, File No. ER-2019-0335.

The margin was calculated by taking the difference between the actual price received and the price that would have been received had the transaction settled at the spot market for the CpNode[16] specified by the transaction and multiplying that difference by the volume. For a bilateral purchase, the calculation is reversed – it is a comparison of the fixed price paid to the spot price which would have been paid.

[16] "CP" stands for "commercial pricing."

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

IV. VOLATILITY AND UNCERTAINTY OF MARKET FACTORS IMPACTING FAC COMPONENTS

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

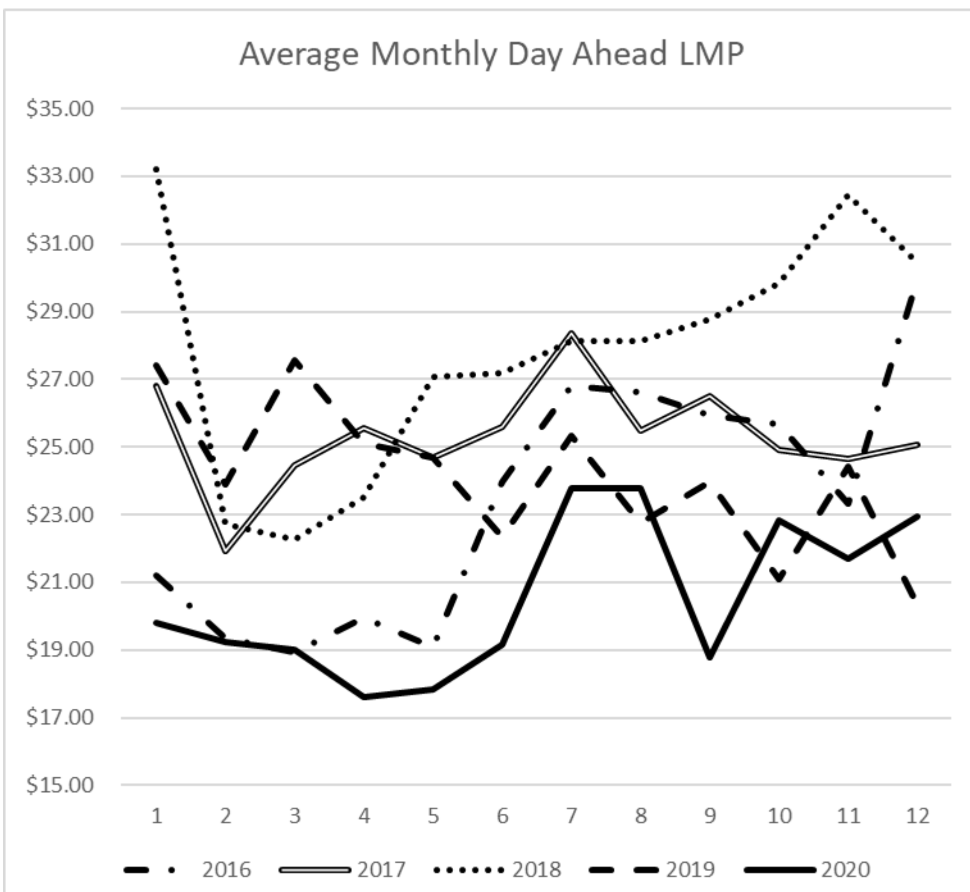
A. Yes, all the cost and revenue components of the FAC – fuel, purchased power, transportation, and off-system sales – continue to be volatile and uncertain. This includes nuclear fuel, coal, natural gas, coal transportation, transmission charges, energy, ancillary services, and net capacity revenues. This is because the costs and revenues associated with all these components are a function of both price and volume. Both price and volume can be significantly impacted by what is occurring in the markets. It must be kept in mind that the volume of the Company's fuel costs (which includes significant coal costs), off-system sales, and spot market prices for fuel commodities and energy are inexorably linked together. The volume of coal (and natural gas) which Ameren Missouri consumes in a given year is a function of the market dispatch of its generating units. That dispatch in the MISO market is a function of the offer price of the unit (based on its incremental fuel cost) and the market price available to the unit for a given hour.

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

Q. Please discuss the volatility and uncertainty of market energy prices.

A. Chart 3 below illustrates the variability in the LMPs against which the Company's units are committed. The values are simply monthly averages of the day-ahead LMP for the MOGEN1 aggregate pricing node in MISO. This node is made up of the Labadie, Rush Island, and Sioux Energy Centers. As this chart clearly shows, these LMPs show significant inconsistency from year-to-year.

Chart 3



Q. Do Ameren Missouri's coal and coal transportation expenses remain volatile and uncertain?

A. Yes, both the price and volume components of these costs remain volatile and uncertain.

The volume component is driven by the market dispatch of these units, which is itself a function of the incremental cost of fuel and market prices, while the price component is driven by the contracts for coal commodity and transportation.

Q. Can you illustrate the volatility and uncertainty in the volume of coal consumed by Ameren Missouri's Energy Centers?

A. Yes. As shown in the Table 1 below, the Company's annual consumption of coal, and the associated cost at its energy centers, varies significantly year-over-year – by tens of millions of dollars.

Table 1

AMEREN MISSOURI ANNUAL COAL CONSUMPTION							
	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	2014	2015	2016	2017	2018	2019	2020
	19,433,000	17,609,000	16,232,000	17,975,000	17,474,000	14,320,000	15,439,000
Total Burn TONS							
Y/Y Change		-1,824,000	-1,377,000	1,743,000	-501,000	-3,154,000	1,119,000
AMEREN MISSOURI COAL COMMODITY AND TRANSPORTATION							
Cost	$ 736,337,348	$ 678,213,385	$ 627,925,199	$ 671,421,565	$ 599,223,417	$ 416,021,545	$ 437,801,094
Y/Y Change		$ (58,123,962)	$ (50,288,187)	$ 43,496,366	$ (72,198,148)	$ (183,201,872)	$ 21,779,549

Q. Is this variability expected to continue?

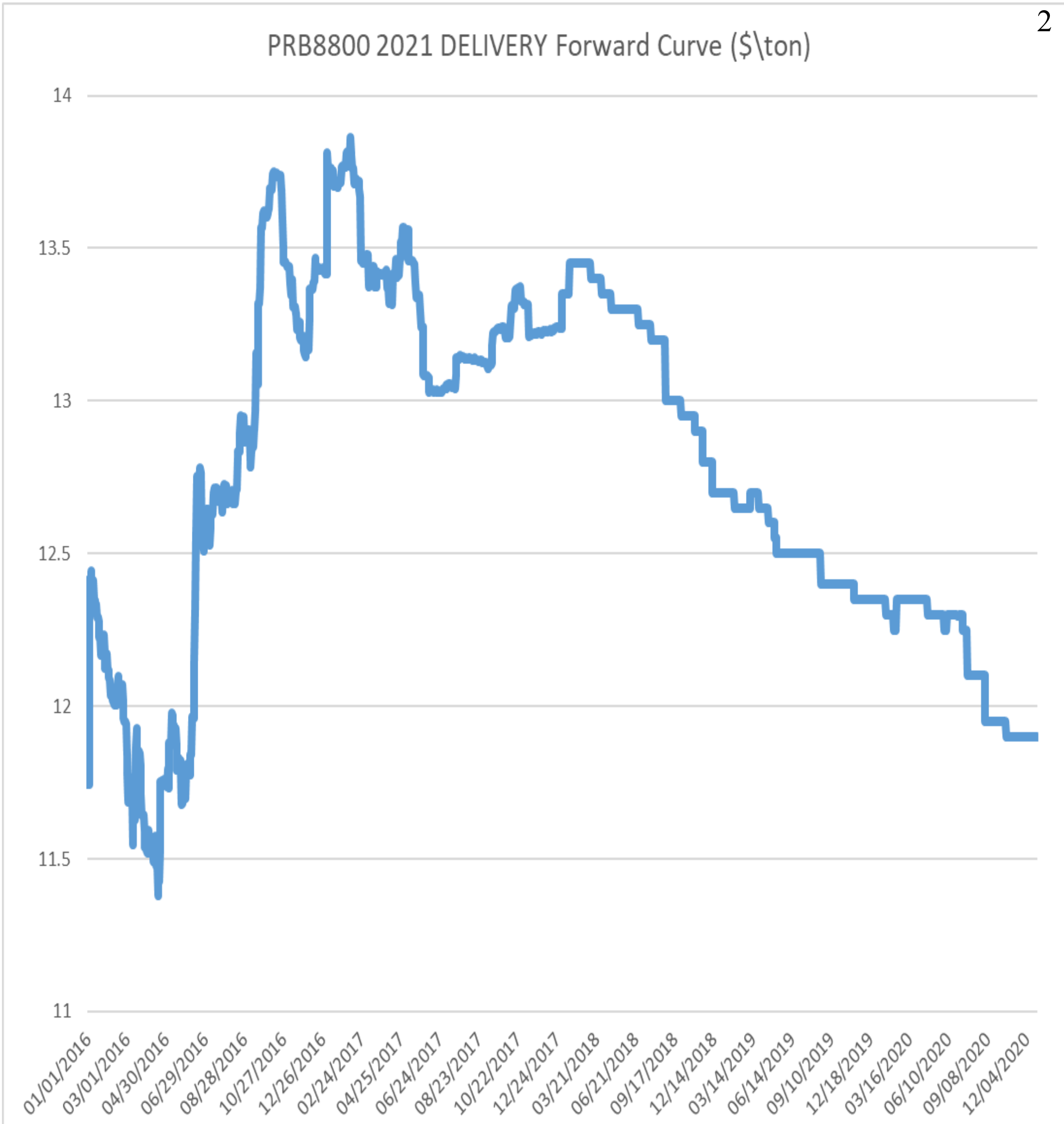
A. Yes. The factors which affect the future dispatch of these units continue to be volatile and uncertain.

Q. Can you illustrate the volatility and uncertainty in the price component affecting coal consumed by Ameren Missouri's energy centers?

A. Yes. As noted above, the price of coal commodity and transportation impacts cost in two ways. First, the incremental cost is used to develop the offers for the Company's generating units in the MISO market, which affects dispatch and thus the volume of coal consumed. Second, the accounting expense is based on the actual contract prices.

Ameren Missouri utilizes a cost-averaging approach to coal procurement, making several fixed-priced purchases for a given delivery year across several years preceding the delivery year that are price-averaged together. As such, Ameren Missouri's price exposure is tied to the forward curves for both Powder River Basin ("PRB") 8800 British thermal unit ("Btu") coal and Illinois Basin thermal coal. Chart 4 below shows the change in the 2020 delivery PRB 8800 forward price curve for the five years preceding the 2020 delivery window. Given that Ameren Missouri consumes in excess of 15 million tons of coal annually on average in recent years, each $1 change in the price results in a change in cost of around $15 million.

Chart 4


PRB8800 2021 DELIVERY Forward Curve ($\ton)
14
13.5
13
12.5
12
11.5
11
01/01/2016
03/01/2016
04/30/2016
06/29/2016
08/28/2016
10/27/2016
12/26/2016
02/24/2017
04/25/2017
06/24/2017
08/23/2017
10/22/2017
12/24/2017
03/21/2018
06/21/2018
09/17/2018
12/14/2018
03/14/2019
06/14/2019
09/10/2019
12/18/2019
03/16/2020
06/10/2020
09/08/2020
12/04/2020

Q. Are there other factors which impact the volatility and uncertainty of Ameren Missouri's coal and transportation costs?

A. Yes. The Company's coal commodity contracts include adjustment provisions for Btu and sulfur dioxide ("SO_2") content. The various transportation agreements include provisions for rail surcharges (based on the price of diesel fuel), escalators tied to railroad cost indices, and in some instances adjustment factors tied to MISO LMPs.

Q. Please discuss the coal quality adjustment provisions of the coal commodity contracts.

A. Each of Ameren Missouri's coal contracts include price adjustment mechanisms based on the difference between contract quality specifications and actual delivered quality. The two quality specifications identified in the coal contracts that result in price adjustments are Btu/lb and pounds of SO_2/MMBtu. Variations in the delivered quality result in price adjustments which impact our cost.

Q. Please discuss the adjustment provisions in Ameren Missouri's rail transportation agreements.

A. Rail surcharge charges are variable costs of rail transportation which compensate the railways for their diesel fuel expenditures. This surcharge is based on On-Highway Diesel Fuel pricing, and if applicable, is also based upon car-miles traveled.

Ameren Missouri's rail transportation contracts also include escalators tied to a railroad cost index (the all-inclusive index less fuel ("AII-LF")). This index is published by the Association of American Railroads and measures the changes in price level inputs to railroad operations: labor, materials and supplies, and other operating expenses. These price adjustments happen quarterly or annually depending upon contract.

Adding even more volatility and uncertainty to the cost of Ameren Missouri rail transportation is a feature in some transportation contracts which indexes freight rates to MISO LMPs. While this structure creates a logical association between prices and coal burn, it also adds to the uncertainty of the overall expense.

Q. Aside from the adjustment provisions discussed above, are Ameren Missouri's PRB rail transportation expenses volatile and uncertain with the Company's multi-year contracts in place?

A. Yes, for the reasons given earlier since cost is a function of price and volume.

Q. Are the costs for fuel additives and emissions volatile and uncertain?

A. Yes, because the volume of these items is a function of generator output, which itself is volatile and uncertain.

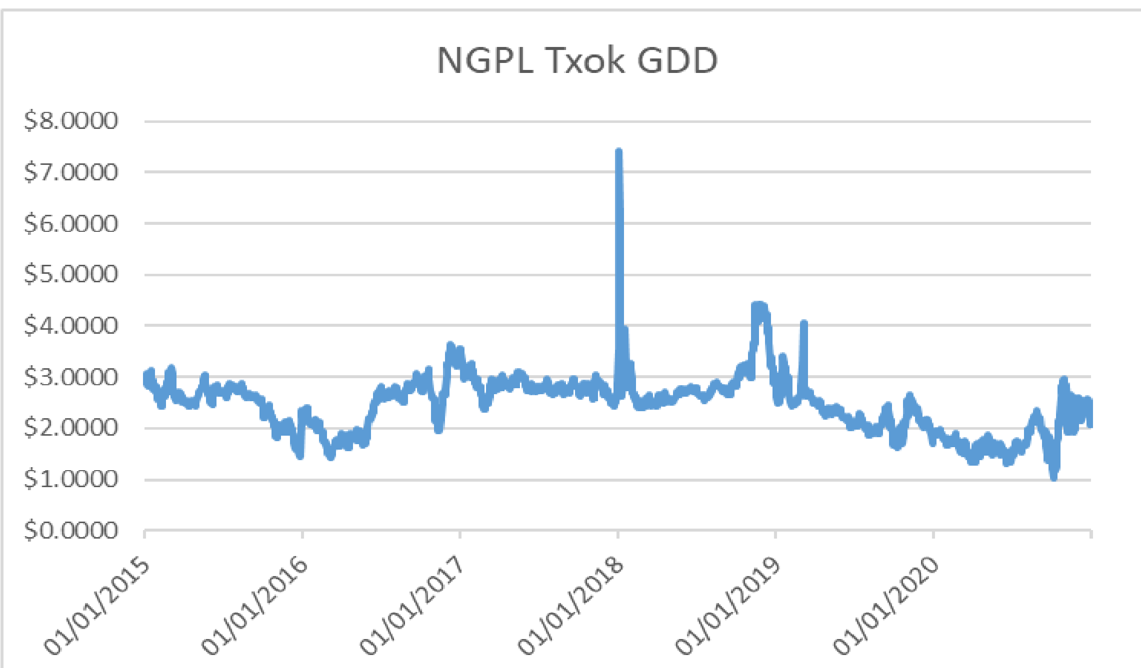
Q. Are Ameren Missouri's natural gas costs, including transportation, volatile and uncertain?

A. Yes. The units in Ameren Missouri's generation fleet which utilize natural gas as a fuel (also referred to as combustion turbine generators or "CTGs") are peaking units. Their output is much less certain and predictable than that of baseload units, such as those at the Labadie, Rush Island, and Sioux Energy Centers.

Additionally, we have limited resources for storing natural gas which we have procured but did not consume.

As a result, Ameren Missouri frequently procures natural gas supplies for its CTGs in the next-day or same-day gas markets, after first having cleared the unit in the MISO market. While gas prices have been relatively low in recent months,[17] there is still significant gas market volatility on a daily and locational basis, especially on peak days. Chart 5 below shows the daily settlement price for the Natural Gas Pipeline Company's TxOk receipt point. This natural gas receipt point is key to Ameren Missouri's gas generation fuel supply, as several simple cycle CTG plants are located on this supply path. Daily prices in the chart (covering calendar years 2015 – 2020) range $1.03 to $7.40, with a mean of $2.47.

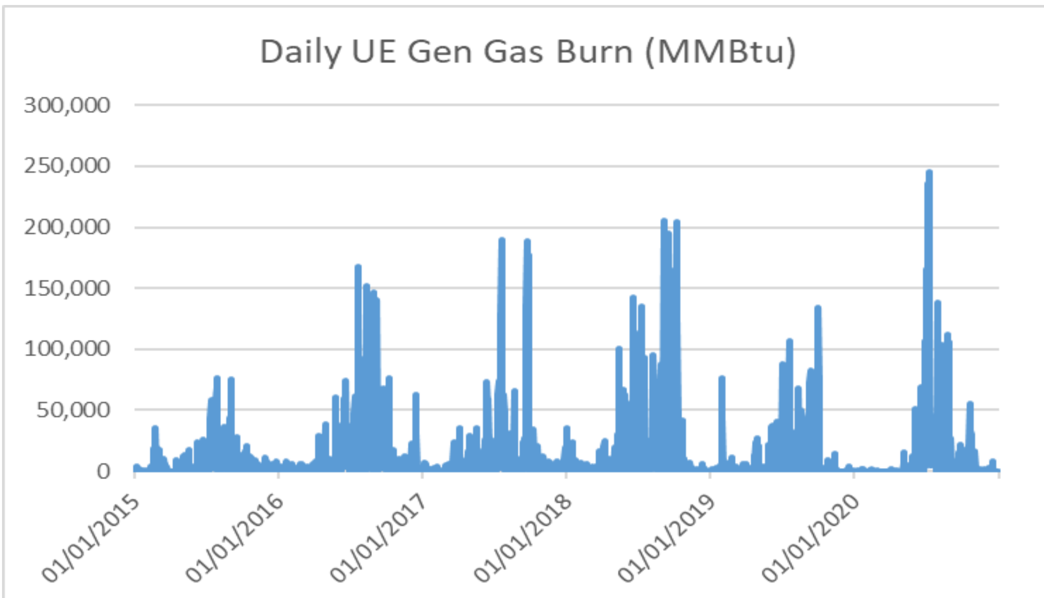
Chart 5



[17] Except during the period of the recent Polar Vortex.

As noted previously, these units are not baseload units and operate infrequently. Chart 6 below visually illustrates the large variability of Ameren Missouri's generation natural gas consumption. Since the natural gas generation fleet is largely committed during peak conditions, the Company is frequently procuring significant amounts of natural gas on volatile pricing days.

Chart 6



Q. Are Ameren Missouri's net off-system sales revenues volatile and uncertain?

A. Yes, for all the reasons outlined above. This volatility and uncertainty is further compounded by the fact that the volume of sales is a function of the amount of customer demand which is bid into the MISO market. The Company's demand is also volatile and uncertain, being dependent to a significant degree on weather.

Q. Please explain how the volume of off-system sales is a function of the amount of customer demand bid into the MISO market.

A. As I discussed earlier, Ameren Missouri operates in a "buy all – sell all" RTO wholesale markets. As a function of the MISO and SPP markets, all the generation which is cleared for a given hour is sold into the market. At the same time, the Company must purchase from the MISO market all the energy needed to meet its load obligations. FERC Order 668 requires that these sales and purchases be netted against each other in each given hour. When the volume of purchases exceeds the volume of sales in a given hour, a net purchase is recorded. When the opposite occurs, a net sale is recorded.

Q. Are Ameren Missouri's net purchased power costs volatile and uncertain?

A. Yes. This is true for both purchases made under the Pioneer Prairie Purchased Power Agreement ("PPA") and net purchased power costs arising from our activities in the MISO market.

Purchases under the Pioneer Prairie PPA are driven by the amount of energy produced at the facility, which is a function of weather. Weather is, and is expected to remain, both volatile and uncertain.

Net purchased power costs arising from activities in the MISO market are volatile and uncertain for the same reasons that our off-system sales revenues are volatile and uncertain.

Q. Are ancillary services revenues and costs volatile and uncertain?

A. Yes. Ancillary services revenues arise through the Company's participation in the MISO market. This market is a spot market – settling both day-ahead and in the real time. Table 2 below shows ancillary services costs and revenues for regulation, spinning reserve, and supplemental reserve services over the past five years, reflecting a range from a net of about $3 million in a given year to a net of about $8 million in another year during this period:

Table 2

Ancillary Services	2016	2017	2018	2019	2020	Avg.
Cost	$ 2.82	$ 3.27	$ 3.26	$ 2.39	$ 2.09	$ 2.77
Revenue	$ (8.27)	$ (9.96)	$ (11.27)	$ (5.47)	$ (6.34)	$ (8.26)
Net	$ (5.45)	$ (6.68)	$ (8.01)	$ (3.07)	$ (4.25)	$ (5.49)

Ancillary services costs are a function of how much load the Company settles in the MISO market. This load is volatile and uncertain, being dependent to a significant degree on weather.

Q. Are capacity revenues and costs volatile and uncertain?

A. Yes. While Ameren Missouri has less uncertainty regarding the volume of capacity sales and purchases that will be required for a given period, the price at which these volumes will settle is volatile and uncertain, as I illustrated above in my discussion of why Ameren Missouri is recommending the use of a multi-year normalization period for these costs and revenues.

Q. Have the results of past MISO annual Planning Resource Auctions demonstrated volatility in the Auction Clearing Price ("ACP")?

A. Yes. The historical ACP in Table 3 below shows the volatility of ACP's over the last several auctions. Ameren Missouri's native load obligation resides in Zone 5 (MO), and generation resides in both Zone 4 (IL) and Zone 5 (MO).

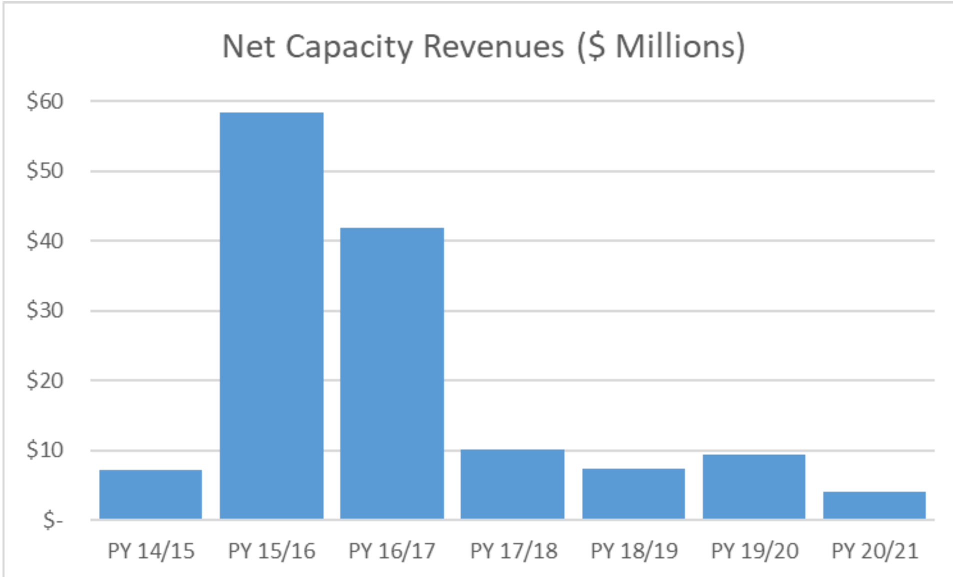
Table 3

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2014-2015</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-
$5.00</td></tr>
<tr><td>IMM Conduct Threshold</td><td>25.61</td><td>25.17</td><td>25.02</td><td>25.46</td><td>26.08</td><td>25.49</td><td>25.75</td><td>24.56</td><td>23.66</td><td>24.50</td><td>26.08</td></tr>
<tr><td>Cost of New Entry</td><td>256.08</td><td>251.67</td><td>250.22</td><td>254.68</td><td>260.79</td><td>254.88</td><td>257.53</td><td>245.64</td><td>236.58</td><td>244.96</td><td>260.79</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-day

As shown in Chart 7 below a review of the net impact of capacity sales and purchases over the past seven MISO Planning Years, going back to June of 2014, reveals significant year-on-year changes, which demonstrates volatility and uncertainty.

Chart 7



V. COMMITMENTS FROM FILE NO. ER-2019-0335

Q. The Commission-approved Stipulation and Agreement resolving all but two issues in the Company's last general rate proceeding reflected certain FAC-related commitments on the Company's part. Has the Company fulfilled those commitments?

A. Yes. The additional FAC reporting discussed in paragraph 10 of the Stipulation and Agreement has been provided, and the documentation described in paragraph 11 of the Stipulation and Agreement is being included in the Company's direct testimony workpapers to be submitted to Staff and the Office of the Public Counsel shortly after this case is filed. Those workpapers will also be made available to any other parties granted intervention in this case.

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 20 CSR 4240-20.090(2)(A)1;

LOCAL PUBLIC HEARING NOTICE

Ameren Missouri has filed tariff sheets with the Missouri Public Service Commission (PSC) that would increase the company's electric service revenues by approximately $299,466,366. The overall request would raise a typical residential customer's bill by approximately 11.97%, translating to an approximately $11.78 monthly increase.

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. The rebasing of net energy costs tracked in the FAC results in a proposed overall revenue decrease of approximately $45,353,454, or 1.82%. 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 approximately 13.79%.

The permanent rate increase request, which is subject to regulatory approval, would take effect no later than February 28, 2022.

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 20 CSR 4240-20.090(2)(A)2;

[1] Each item (1) …. (19) corresponds to the subparagraphs in 20 CSR 4240-20.090(2)(A).

Attached hereto as Attachments A and B are examples of customer bills for the 1M, 2M, 3M, 4M, and 11M classes.

(C) Proposed RAM tariff sheets in accordance with 20 CSR 4240-20.090(2)(A)3;

Attached to the testimony to which this Schedule is attached as Schedule AMM-D3 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 20 CSR 4240-20.090(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). As discussed in the testimony to which this schedule is attached, there are four different voltage adjustment factors (one applicable to customers taking service at secondary voltage; three for primary service customers), consistent with the agreement reached in the stipulation that resolved the Company's last electric rate review.

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 20 CSR 4240-20.090(2)(A)5;

[2] Consistent with the Commission's *Order Approving Unanimous Stipulation and Agreement* in File No. ER-2019-0335, 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.

Ameren Missouri's continued FAC tariff, which is substantially the same as its existing FAC, continues to be reasonably designed to provide Ameren Missouri with a sufficient opportunity to earn a fair return on equity for several reasons. First, it provides for full and timely recovery of 95% of the changes in Ameren Missouri's actual net energy costs (which, in general terms, consist of fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues), by reflecting increases and decreases in such costs in rates. 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 20 CSR 4240-20.090(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 20 CSR 4240-20.090(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 20 CSR 4240-20.090(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, 20

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

CSR 4240-20.090(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 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, 20 CSR 4240-3.190 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 20 CSR 4240-20.090(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.

[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.

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

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, 1.87% 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-2019-0335.

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 20 CSR 4240-20.090(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, supplemental reserve, and ramp capability services. Make-whole payments shall include price volatility and revenue sufficiency guarantees.

Transmission Revenues. 1.87% of transmission revenues recorded in FERC account 456.1 have been included, consistent with the methodology approved by the Commission in File No. ER-2019-0335.

(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 20 CSR 4240-20.090(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.

[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.

(L) A detailed explanation of any rate volatility mitigation features designed in the proposed RAM in accordance with 20 CSR 4240-20.090(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. 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 20 CSR 4240-20.090(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.

<u>Fuel and Power Accounting</u>

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 and sold within the MISO and SPP markets, Ameren Missouri utilizes the PCI system. This system maintains the detailed charges and statistics pulled directly from the MISO and SPP Portals. It gathers Company-provided inputs (e.g., meter data) and RTO-provided data and performs a parallel calculation of expected charges. This recalculation serves as the primary control concerning RTO 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 and sold outside the MISO and SPP markets is recorded in the trade management system called Endur, 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 settlement files. The settlement files are downloaded from the MISO portal. A Transmission Policy Specialist creates a monthly summary file assigning the corresponding accounting to the revenues and expenses based on the 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 summary file to Power Accounting. Power Accounting uses the 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 audits of the Fuel Adjustment Clause periodically, based on a risk-based audit plan, 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.

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 the MISO market,[8] 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, a net charge is shown in FERC Account 555. All RTO-related activity is retrieved from the appropriate RTO Portal and validated using PCI software. In addition to these net purchased power costs from MISO 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 20 CSR 4240-20.090(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

[8] Ameren Missouri's recently-acquired Atchison County wind energy facility sells its output into the Southwest Power Pool market.

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 Ann Bulkley 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 20 CSR 4240-20.090(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 20 CSR 4240-20.090(2)(A)16;

On September 28, 2020, Ameren Missouri made its most recently required triennial Integrated Resource Plan ("IRP") filing (EO-2021-0021), reflecting that important objectives of Ameren Missouri's IRP process are to minimize overall delivered energy costs and provide reliable service while transitioning to cleaner energy generation and reduced carbon dioxide emissions. 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 20 CSR 4240-22.010, 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."[9] Ameren Missouri's next triennial IRP filing is due October 1, 2023.

(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 20 CSR 4240-20.090(2)(A)17;

Ameren Missouri has an established compliance strategy for the 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

[9] 20 CSR 4240-22.010(2).

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 SO2 emissions from those units. No additional capital projects are necessary or planned for SO2 compliance over the next five years.

Ameren Missouri's strategy for compliance with both the annual and ozone season CSAPR NOx trading programs is for continued combustion of Power River Basin ("PRB") sub-bituminous coals and the operation and optimization of low NOx burner ("LNB") and over-fire air ("OFA") systems in conjunction with the installed neural net optimization systems at the Labadie, Rush Island and Meramec coal-fired energy centers. These systems, along with the combustion of PRB coals, work to minimize NOx emissions. The installed selective non-catalytic reduction ("SNCR") systems at the Sioux Energy Center are operational and available for use should additional NOx reduction be needed at those units during the ozone season to keep systemwide NOx emissions at or below CSAPR allowance levels. The cost of operation of the SNCR systems is compared to the cost of purchasing additional NOx allowances to determine the most cost effective compliance approach. Ameren Missouri does not anticipate that significant purchases of ozone season NOx emissions allowances will be required to comply.

Ameren Missouri began operating under the CSAPR on January 1, 2015. Since the CSAPR was a new program, there were no previous allowance banks for companies to rely on for compliance in 2015. Ameren Missouri received approval from the Missouri Public Service Commission to manage its allowance bank of SO2 and NOx allowances under the CSAPR. Ameren Missouri is in compliance with the current Phase 2 allowance allocations for the CSAPR programs through utilization of the installed pollution control equipment, low sulfur coal and natural gas and currently has sufficient allowances for compliance in future years. Ameren Missouri currently intends to use all of its SO2 allowance allocations associated with the CSAPR to comply with the rules and to provide maximum flexibility in the timing of any additional SO2 control technology installations that may be required for compliance with future SO2 rules.

(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 20 CSR 4240-20.090(2)(A)18;[10]

(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 20 CSR 4240-20.090(2)(A)19.

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

Ameren MISSOURI

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- Pay online or manage your account: AmerenMissouri.com
- Customer Service: 1.800.552.7583

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Current Charge Detail for Statement 09/18/2020

Electric Energy Charge - Residential	$100.39
Electric Customer Charge - Residential	$9.06
Renewable Energy Adjustment	$0.37
Fuel Adjustment Charge	-$1.76
Energy Efficiency Investment Charge	$3.35
Missouri Local Sales Tax	$1.67
Holt-Clay Co Municipal Charge - Service	$5.86
Amount Due	**$118.94**

AMOUNT DUE $118.94

Due Date: 10/09/2020

Account Number

Customer Name

Service Address

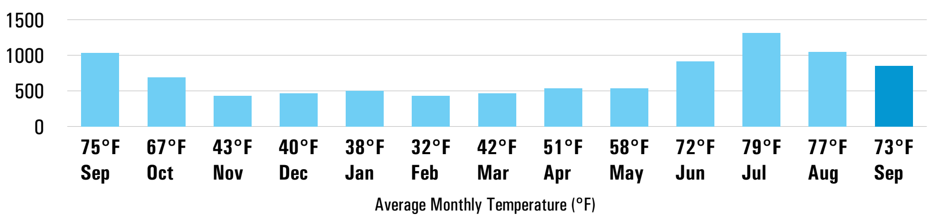
Previous Statement	$144.54
Last Payment - 08/28/2020	$144.54

Electric Service from 08/17/2020 - 09/16/2020 30 Days

	Meter Number	Current Reading	Previous Reading	Current Usage	Reading Type
E		078270	077420	850 kWh	Actual

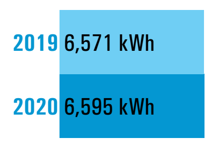
Electric Service Details — September Statement

Electric Usage in Kilowatt Hours (kWh)



Electric Usage Summary (kWh)

Your electric energy usage this year was about the same as last year



Usage from Jan-Sep for 2019 & 2020

56679 13073
04385 6408035 004386 008771 0001/0001
INTERNAL USE ONLY

IF YOU NEED ASSISTANCE, WE'RE HERE TO HELP.

If you are having trouble paying your bill, help is available, and we encourage you to take action now. Avoid late fees and disconnection by applying for energy assistance.

And remember, scammers are out there. If you receive a suspicious message or phone call demanding payment, check your account online or call us.

Learn more at **AmerenMissouri.com/EnergyAssistance** or call **1.800.552.7583**.

> > See reverse for messages

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AMOUNT DUE	Due Date
$118.94	October 09, 2020
Delinquent Amount After Due Date	**Account Number**
$120.81	

Amount Enclosed: $

AMEREN MISSOURI
PO BOX 88068
CHICAGO IL 60680-1068

6220000 0014138041109 00120810 00118940 00118940

SCHEDULE AMM-D1 Attachment A
Page 1 of 2

Account Messages

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.

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

You're in control with Budget Billing. Your energy payments will be predictable. Avoid surprises and gain peace of mind. Enroll in Budget Billing by sending only $84.00. Payment must be received by the 'Due Date' on this bill.

Ameren Missouri's Community Solar program enables your home or small business to support renewable energy in Missouri through an easy monthly subscription. Learn more at Amerenmissouri.com/communitysolar.

Seasonal Rate Change - Your electric bills for the next eight months will reflect the lower winter costs for providing electric service. Look for ways to control your winter bills by visiting AmerenMissouri.com/ActOnEnergy for tips and rebates.

Easy HVAC Energy Saving Tip

Check your filter every month. A dirty filter will slow down air flow and make the system work harder to keep you cool — wasting energy. At a minimum, change the filter every 3 months to lower your energy use.

If your system isn't keeping you cool, replace it with a new energy efficient air source heat pump and get up to **$900 cash back**.

For more details and other rebates, visit **AmerenMissouriSavings.com/AC**

Address Changes or Corrections

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

AmerenMissouri.com/WaysToPay

ONLINE E-CHECK

ONLINE CREDIT CARD

PHONE 866.268.3729

MAIL STUB & CHECK

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

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- Pay online or manage your account: AmerenMissouri.com
- Customer Service: 1.877.426.3736

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Account Number
Customer Name
Service Address

AMOUNT DUE	**$2,154.63**
Due Date	**09/29/2020**
Amount After Due Date	$2,189.38
Previous Statement	$1,388.60
Total Payments	$1,388.60

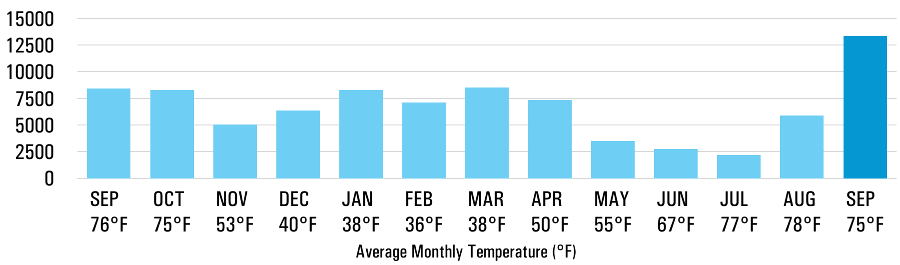
Payment Received. Thank You.

Current Detail for Statement 09/08/2020

Total Electric Charges	$2,154.63
Total Amount Due	**$2,154.63**

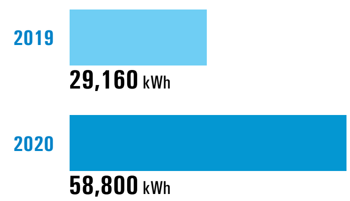
Electric Usage History

Electric Usage in Kilowatt Hours (kWh)



Electric Usage Summary (kWh)

This shows how much electric energy you've used at this address.



Usage from Aug 2019 to Sep 2020

00003 6400019 000024 000047 0005/0010

Electric Service Details

Service from 08/05/2020 - 09/03/2020 (29 days)

Electric Meter Read

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
	08/05 - 08/17	12	Total kWh	Actual	38898.0000	38860.0000	38.0000	120.0000	4560.0000
	08/05 - 08/17	12	Peak kW	Actual	0.3100	0.0000	0.3100	120.0000	37.2000
	08/17 - 09/03	17	Total kWh	Actual	73.0000	0.0000	73.0000	120.0000	8760.0000

» See next page for service details.

Keep this portion for your records.

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Amount Due	Due Date
$2,154.63	September 29, 2020
Delinquent Amount After Due Date	**Account Number**
$2,189.38	

Amount Enclosed $ ____________________

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PO BOX 88068
CHICAGO IL 60680-1068

Schedule AMM-D1 Attachement B
Page 1 of 4

90600000 002901114040b 000002154630 000002154630

Electric Service Details (Continued)

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
	08/17 - 09/03	17	On Peak kWh	Actual	38.0000	0.0000	38.0000	120.0000	4560.0000
	08/17 - 09/03	17	Off Peak kW	Actual	0.3670	0.0000	0.3670	120.0000	44.0400
	08/17 - 09/03	17	On Peak kW	Actual	0.4940	0.0000	0.4940	120.0000	59.2800

Usage Summary

Total kWh	13320.0000	Peak kW	59.3000
Billing Demand	59.3000	Total Billing Demand	100.0000

Rate 3M Large General Service

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Demand Charge	100.00	kW	@	$ 5.40000000	$540.00
Energy Charge/Hours Used	8,895.00	kWh	@	$ 0.09690000	$861.93
Energy Charge/Hours Used	4,425.00	kWh	@	$ 0.07290000	$322.58
Customer Charge					$95.29
Fuel Adjustment Charge	13,320.00	kWh	@	$-0.00207000	$-27.57
Energy Efficiency Investment Charge	13,320.00	kWh	@	$ 0.00383900	$51.14
Renewable Energy Adjustment	13,320.00	kWh	@	$ 0.00044000	$5.86
				Total Service Amount	**$1,849.23**

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Missouri State Sales Tax	$1,849.23		@	$ 0.04225000	$78.13
Missouri Local Sales Tax	$1,849.23		@	$ 0.04763000	$88.08
Florissant Municipal Charge - Service	$1,849.23		@	$ 0.07527000	$139.19
				Total Tax Related Charges	**$305.40**

Total Electric Charges **$2,154.63**

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

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- Customer Service: 1.877.426.3736

AMOUNT DUE	**$2,154.63**
Due Date	**09/29/2020**
Account Number	
Service Address	

Payments Since Previous Statement

DATE RECEIVED	AMOUNT
August 31, 2020	$1,388.60

Account Messages

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

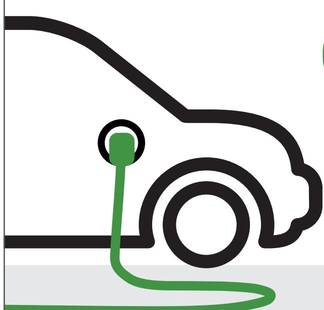
Seasonal Rate Change - Your electric bills for the next eight months will reflect the lower winter costs for providing electric service. Look for ways to control your winter bills by visiting AmerenMissouri.com for tips on using energy efficiently.

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

REACH OUT IF YOU NEED ASSISTANCE. WE'RE HERE TO HELP.

If you are having trouble paying your bill, we want you to know there is help available. On July 15, 2020, we returned to regular policies regarding disconnecting for nonpayment and assessing late fees. Assistance is available, so we encourage you to take action now.

Visit **AmerenMissouri.com/BusinessHelp** or call **1.877.426.3736**.



GET PAID TO INSTALL EV CHARGING STATIONS

Install EV charging stations at your business or multi-family apartment building and **earn up to 50%** of the cost in incentives. Plus take advantage of **federal tax credits** through the end of the year. EV charging stations can provide a benefit to your employees, customers and community while helping establish your company as a leader in sustainability and innovation.

Visit AmerenMissouri.com/ChargingIncentives to learn more.

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AMM-D1 Attachments C and D filed as separate attachments

Schedule AMM-D2 Filed

as separate attachment

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(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 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 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.

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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:

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

Where:

ANEC = FC + PP + E ± R − OSSR

FC = Fuel costs and revenues associated with the Company's generating plants 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;

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, recorded in FERC Account 518: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

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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 the subscribed portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor PP, (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~~(c) 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);

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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.

2) One and ~~44~~87/100 percent (1.~~44~~87%) of transmission service costs reflected in FERC Account 565 and one and ~~44~~87/100 percent (1.~~44~~87%) of transmission revenues reflected in FERC Account 456.1 (excluding (a) amounts associated with the subscribed portions of Purchased Power Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from this Factor PP and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule). Such transmission service costs and revenues included in Factor PP include:

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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)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.

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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.)

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 or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR 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 or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR 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.

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.)

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

B = BF x S_{AP}

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is $0.~~01259~~01149 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.~~01167~~01036 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).

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).

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.)

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 (“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.

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 = 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.

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}.

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

RAC = Rate Adjustment Cap: applies to the FAR rate 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 rate as determined under Section 393.1655.4 by the 2.85% Compound Annual Growth Rate compounded for the amount of time in days 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~~0455%.

Schedule AMM-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.)

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

Secondary Voltage Service (VAF_{SEC})	1.~~0570~~0539
Primary Voltage Service (VAF_{PRI})	1.~~0224~~0222
High Voltage Service (VAF_{HV})	1.0059
Transmission Voltage Service (VAF_{TRANS})	0.9928

Customers served by the Company under Service Classification No. 11(M), Large Primary Service, shall have their rate capped such that their FAR_{LPS} does not exceed RAC_{LPS}, 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 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 in days 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.

FAR_{LPS} = The weighted average of the voltage specific Fuel Adjustment ~~Rate~~Rates that will be applicable to customers taking service under Service Classification No. 11(M), Large Primary Service, which is calculated as the ~~minimum~~lesser of (a) the Combined Initial Rate Component for ~~the FAR applicable to Primary Voltage Service and~~ RAC_{LPS} Comparison or (b) RAC_{LPS}.

Combined Initial Rate Component for RAC_{LPS} Comparison = The sum of the products of each of the Primary, High Voltage, and Transmission Initial Rate Components for the Individual Service Classifications and the applicable following LPS Weighting Factor(WF):

Primary Voltage LPS Weighting Factor (WF_{PRI})	0.1587
High Voltage LPS Weighting Factor (WF_{HV})	0.3967
Transmission Voltage LPS Weighting Factor (WF_{TRANS})	0.4446

Schedule AMM-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.)

Where the Combined Initial Rate Component for ~~Primary Customers~~RAC_{LPS} Comparison 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 = (((Combined Initial Rate Component For ~~Primary Customers~~RAC_{LPS} Comparison – FAR_{LPS}) 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 Non-LPS 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)
FARHV = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAFHV)
FARTRANS = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAFTRANS)

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

LPSFARPRI = Initial Rate Component For Primary Customers x LPS RAC Cap Multiplier
LPSFARHV = Initial Rate Component For High Voltage Customers x LPS RAC Cap Multiplier
LPSFARTRANS = Initial Rate Component For Transmission Customers x LPS RAC Cap Multiplier

Where the LPS RAC Cap Multiplier is the FAR_{LPS} divided by the Combined Initial Rate Component for RAC_{LPS} Comparison.

The FAR applicable to the individual Service Classifications, including the calculations on Lines ~~16~~24 through ~~21~~29 of Rider FAC, 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 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.

RIDER FAC

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

GENERAL RATE CASE/PRUDENCE REVIEWS

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

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

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

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

FAC CHARGE TYPE TABLE

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

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

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 Schedule 49 Distribution
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;

MISO 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 Schedules 26-C & 26-D - (TMEP Cost Recovery);
MISO Schedule 33 (Black Start Service);
MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

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

DA Market Administration Amount;
DA Schedule 24 Allocation Amount;
FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;
RT Market Administration Amount;
RT Schedule 24 Allocation Amount;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

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;
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);
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 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;

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

FAC CHARGE TYPE TABLE (Cont'd.)

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;
Auction Revenue Rights Funding;
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 Contingency Reserve Deployment Failure
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;
RT Unused Regulation -Down Mileage Make Whole Payment;

RIDER FAC

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

FAC CHARGE TYPE TABLE (Cont'd.)

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;
Schedule 1A2 – Transmission Congestionk Rights Administratoin
Schedule 1A3 – Integrated Marketplace Clearing Administration
Schedule 1A4 – Integrated Marketplace Facilitation Administration
Schedule 12 – FERC Assessment;

Schedule AMM-D3

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 Adjust Its Revenues for Electric Service.	)))	Case No. ER-2021-0240

AFFIDAVIT OF ANDREW MEYER

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

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

My name is Andrew Meyer, and on his oath declare that he is of sound mind and lawful age; that he has prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

Andrew Meyer

Andrew Meyer

Sworn to me this 30th day of March, 2021.