Exhibit No.:	
Issue(s):	Fuel Adjustment Clause; Unit Offers & Unit Commitment
Witness:	Andrew Meyer
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2019-0335
Date Testimony Prepared:	January 21, 2020

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

REBUTTAL TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January, 2020

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

ANDREW MEYER

FILE NO. ER-2019-0335

I. INTRODUCTION

Q. Please state your name, business address, and by whom you are employed.

A. Andrew Meyer, 1901 Chouteau Avenue, St. Louis, MO 63103. I am employed by Union Electric Company d/b/a Ameren Missouri (the "Company" or "Ameren Missouri").

Q. Are you the same Andrew Meyer that filed direct testimony in this proceeding?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the following:

1. The apparent suggestion by Office of the Public Counsel ("OPC") witness Ms. Lena Mantle that the Company has or may seek to manipulate the level at which its net base energy costs ("NBEC")[1] are

[1] NBEC reflect the base level of net costs and revenues covered by the FAC. Changes in FAC components that are covered by the FAC are then tracked against NBEC for purposes of future FAC rate adjustments between rate cases.

set in each rate case as a means to take unfair advantage of its Fuel Adjustment Clause ("FAC") mechanism;

2. Ms. Mantle's recommendation to change the sharing percentage applied to changes in cost and revenues tracked in the FAC from 95%/5% to 85%/15%;
3. Sierra Club witness Mr. Avi Allison's recommendation regarding retention of analyses underlying unit commitment decisions;
4. A portion of Mr. Allison's recommendation regarding revisions to the Commission's FAC processes (Ameren Missouri witness Tom Byrne will address Mr. Allison's main points in this regard);[2]
5. Mr. Allison's claim that the Company has offered its coal units into the Midcontinent Independent System Operator, Inc.'s ("MISO") market at prices below its variable cost of production; and
6. Mr. Allison's claim that Ameren Missouri's unit commitment practices caused the Company to incur unnecessary net operational losses.

Q. Are you sponsoring any schedules?

A. I am sponsoring one schedule: Schedule AMM-R1, outlining Commission rulings regarding various proposals to impose greater FAC sharing percentages on the utility.

III. OPC CLAIMS REGARDING FAC MANIPULATION

Q. What is the premise of Ms. Mantle's FAC manipulation testimony?

[2] Regarding the FAC, I will also briefly address a slight modification to the FAC tariff change proposed in the Direct Testimony of Company witness Marci L. Althoff relating to transmission charges.

A. Ms. Mantle's clear suggestion is that Ameren Missouri might have been willing to set its NBEC too low in this case, and thus might be willing to forego recovery of millions of dollars in prudently incurred net energy costs, for a purported benefit of receiving positive press reports on this case, which seeks a small overall rate decrease. Her theory, in her hypothetical NBEC manipulation scenario, is that if NBEC are set too low, customers will end up experiencing an overall rate increase once future FAC adjustments occur.

Q. Does Ms. Mantle offer any basis for her claim that Ameren Missouri has an incentive to understate NBEC, or that it has done so in this or any other case?

A. No. She offers no rationale other than the suggestion that even though taking such a step would cost the Company money (through its 5% share of any actual net energy cost increases above this claimed artificially-low base), the Company might be "willing to take" that step "so that it can characterize its request as a rate decrease in the general rate case." Mantle Direct, p. 4, ll. 13-15.

Q. **Is Ameren Missouri willing to manipulate the FAC for a theoretical public relations benefit?**

A. No. Ameren Missouri would not manipulate its FAC filings under any circumstances, whether or not it might benefit from such a manipulation. Integrity is a core value of Ameren, and administering the FAC in a straightforward, non-manipulative way is part and parcel of living that value.

Q. Would there truly be a public relations benefit in setting NBEC artificially low as Ms. Mantle suggests?

A. No. In fact, manipulating NBEC in the manner suggested by Ms. Mantle would generate more *negative* press than positive. It warrants noting that Ms. Mantle completely ignores the fact that if the Company were to do so it would set itself up for *multiple* press reports when there are subsequent increases in charges under the FAC, as evidenced by the following sampling of prior press reports when the Company's FAC rate has gone up:

- "Ameren gets OK for $71.6 million rate increase";
- "Ameren asks for $51 million electric rate increase";
- "Ameren Missouri asks to increase fuel charge"; and
- "Ameren Missouri bills to go up."[3]

Q. Would the Company intentionally subject itself to negative press in the following FAC adjustment filings, all of which would presumably be higher than they otherwise would be (absent NBEC being set artificially low)?

A. No. The Company would not do so, nor has it done so in this or any other case.

Q. What is the amount that Ms. Mantle suggests that the Company would be willing to forego in exchange for positive press?

A. In her direct testimony (p. 4, ll. 23-26), Ms. Mantle states that Ameren Missouri is "reducing its normalized FAC costs by $108 million – a reduction in revenue of which 95% can quickly be remedied through an FAC adjustment following this general

[3] *St. Louis Post-Dispatch*, Sept. 17, 2010*; St. Louis Post-Dispatch,* Mar. 23, 2013; *St. Louis Post-Dispatch*, Jul. 29, 2014; *St. Louis Business Journal* September 19, 2014.

rate case should Ameren Missouri show its actual fuel costs to be more than what was normalized and included in base rates in this case."

The clear suggestion of this testimony is that Ameren Missouri is willing to forego recovery of 5% of the claimed artificial reduction. Assuming the entire $108 million reduction was artificial, the Company would intentionally forego recovery of $5.4 million annually (5% of $108 million) until the next time the FAC is rebased in a rate review proceeding, all for a short-lived public relations stunt. I can tell you from personal experience having worked at Ameren for more than 20 years that the Company is not willing to throw away millions of dollars in this or any other fashion.

Q. Was the Company clear when it filed this case that while base rates are expected to produce approximately $1 million less in annual revenues as a result of this case, absent rebasing NBEC the case would have produced a base rate increase?

A. Yes. The Local Public Hearing Notice proposed by the Company and filed with the Company's direct case explicitly stated as follows:

> All of the reduction in base rates proposed by this case is caused by rebasing these net energy costs. In this case the reduction in costs due to the rebase of net energy costs is offset by net increases in other costs. If the net energy costs had not been rebased in this case, the base rates that would have been proposed would have increased the typical residential customer's bill by 3.7%.

I should also note that the Company, Staff, and OPC all agreed upon the final local public hearing notice that the Company has now sent to all of its approximately 1.2 million customers containing that exact notice that spells out that absent the NBEC reduction, this case would have sought a rate increase.

Q. Do you have any other observations regarding Ms. Mantle's reference to the $108 million reduction in Ameren Missouri's NBEC?

A. Yes. By indicating that "95% can quickly be remedied through an FAC adjustment following this general rate case should Ameren Missouri show its actual fuel costs to be more than what was normalized and included in base rates in this case," it is apparent that Ms. Mantle is suggesting to the Commission that the NBEC presented in the Company's direct filing is understated by a like amount.

By offering this suggestion, Ms. Mantle overlooks or outright ignores that the Company does not unilaterally establish its revenue requirement, including that part of its revenue requirement consisting of NBEC. The Staff performs its own review of all the components of NBEC and makes its own determination and recommendation. In this particular area, NBEC, Staff not only reviews the Company's historical test year (as trued-up) costs, but it also performs its own production cost modeling, upon which the level of NBEC reflected in the revenue requirement is heavily based. Ultimately, the Staff presents its own calculation of NBEC.

Q. Assuming Ms. Mantle's proposed motive for manipulation were reasonable, and Ameren Missouri were willing to manipulate its FAC filings, would it be possible for Ameren Missouri to manipulate the rebasing of NBEC?

A. No, for several reasons. First, as noted above, to do so would assume the Staff will fail to perform its duties. There is no reason to believe that Staff would neglect this responsibility.

Second, Ameren Missouri's calculation of NBEC is performed using well-established practice, using actual historical values as the rate case process in Missouri has always required. NBEC represents a combination of results from the production cost modeling presented by Ameren Missouri witness Hande Berk, normalized test year actuals, and certain specific adjustment factors. All of these factors are reviewed by Staff, at a minimum, and the approach in arriving at them is consistent with the approach used in many Company rate cases over the past several years, including cases where NBEC went *up* from case to case.

As Ms. Berk explained in her direct testimony, the production cost modeling uses assumptions that are based on normalization of historical actual data (e.g., market prices, incremental fuel costs, outage rates, etc.), current operating parameters, and actual fuel costs (in this case, as of January 1, 2020). The Company does not create these inputs at its own discretion. Each of these values is reviewed in detail by Staff.

Other portions of NBEC (e.g., ancillary services revenues, capacity revenues/costs, transmission costs/revenues, and miscellaneous MISO costs) represent the normalization of actual historical costs. Again, these are not discretionary values created by the Company. Each of these values is also closely reviewed by Staff.

Additionally, there are certain adjustment factors included in NBEC. These include the real time, revenue sufficiency guarantee make-whole payment margin adjustment, the financial swap and bilateral margin adjustment, and the real-time load and generation deviation adjustment. Each of these is calculated using actual historical data and is reviewed by Staff.

Q. Is there anything particularly notable about the adjustment factors that you just mentioned that were included in Company's NBEC calculation in this case?

A. Yes. Each of those adjustments was in past cases proposed as an important component of NBEC not by the Company, but by *other parties.* Each such adjustment is thought to improve the accuracy of NBEC. In this case, these adjustment factors as it turns out collectively reduce NBEC in excess of $18 million.

Q. Has Ms. Mantle attempted to measure the reasonableness of Ameren Missouri's NBEC?

A. No. She claims (p. 4, ll. 17-20) that "OPC does not have the ability to determine a normalized FAC cost for Ameren Missouri." She goes on to state that she is "reviewing Ameren Missouri's normalized FAC costs and will review Staff's fuel costs to determine the reasonableness of the FAC costs included in this case." (*Id.*)

Q. How does the NBEC calculated by Staff compare with that presented in the Company's direct case?

A. Staff's NBEC is <u>lower</u> than Ameren Missouri's by $4.5 million. If the Company has understated NBEC in this case, the Staff has understated it by even more.

Q. Why are NBEC in this case lower than they were when last set primarily using data for the 12 months ending December 31, 2016, in File No. ER-2016-0179?

A. Because of significant changes in FAC components since that time. In fact, the largest single driver of the reduced NBEC is the result of the Company's prudent and diligent actions to decrease fuel costs, specifically the delivered cost of its largest fuel expense – coal – since the last rebase of NBEC.

Q. Please elaborate.

A. Since NBEC were last established in File No. ER-2016-0179, Ameren Missouri has achieved significant fuel cost reductions. These include reductions in coal transportation rates. The Company negotiated contract extensions with both the Union

Pacific and the BNSF Railways with effective dates after NBEC were set in the last rate review. Both contracts included downward rate adjustments. The Union Pacific extension was effective on April 1, 2018. The BNSF contract extension was effective January 1, 2020. The NBEC proposed in this case (by the Company and the Staff) reflect those lower contract rates. In addition to transportation, expenses for the coal commodity itself are reduced in this case as compared to coal costs reflected in NBEC in the last case. This is owing to the Company's continued efforts to layer in coal contracts for forward delivery, at negotiated coal costs well below procurement costs in the 2016 case.

Q. So am I to understand that the Company is proposing to use coal commodity and coal transportation contract prices as of the day after the true-up date in this case, i.e., as of January 1, 2020?

A. Yes. The Company's direct case filing utilized the lower prices negotiated by the Company that take effect on January 1, 2020. While this was obviously the right thing to do given that these new prices are known and measurable just one day after December 31, 2019, if the Company wanted to manipulate the FAC, it could have attempted to use prices as of December 31, 2019, which are higher. Then, when the lower January 1, 2020 prices actually took effect and were reflected in lower actual net energy costs tracked in the FAC, the Company could have pocketed 5% of the reduction. The Company didn't manipulate NBEC in this way, just as it did not manipulate NBEC to gain a momentary bump in public perception through press coverage.

IV. FAC SHARING PERCENTAGES

Q. Please address Ms. Mantle's recommendation to change the FAC sharing percentages from 95%/5% to 85%/15%.

A. The recommendation to change the sharing percentage, claiming a need for greater incentives for the Company to manage its net energy costs, is simply a repeat of similar proposals this Commission has rejected, on numerous occasions, in the past. The timing of such a recommendation and the claim that there is a need for greater Company incentives is perplexing, considering this case includes a $108 million reduction to NBEC, as compared to the NBEC reflected in the revenue requirement used to set base rates in File No. ER-2016-0179.

Q. Please discuss Ms. Mantle's claim that Ameren Missouri needs greater incentive to manage FAC costs.

A. Ms. Mantle states that "increasing the share of savings/losses for Ameren Missouri would create a greater incentive for Ameren Missouri to manage the FAC costs that it incurs and passes on to its customers. It would also reduce the likelihood of gamesmanship with the FAC as previously described in this testimony." (p. 5, l. 24 to p. 6, l. 2).

As to the latter justification – the claim that "gamesmanship" (manipulation) could be reduced – I've already demonstrated the complete fallacy of Mr. Mantle's premise. With respect to the "more sharing would create more incentive," Ms. Mantle's theory is not only wrong but is rebutted by the facts. As previously discussed, Ameren Missouri diligently and effectively negotiated large delivered coal cost reductions under the existing and longstanding 95%/5% sharing mechanism. Despite Ms. Mantle's arithmetic demonstration of how the Company would have retained more of the savings under her proposal, the Company did not need a 15% sharing mechanism as incentive to deliver savings for its customers – and we do not need that incentive in the future. As the Company has repeatedly noted, it does not need a greater (or any) sharing percentage to do the right thing for customers – the risk of disallowance or the outright loss of its ability to utilize a FAC are more than sufficient.

Q. Hasn't the Commission previously ruled on the issue of FAC sharing mechanism?

A. Yes, on many occasions. In the first couple of years after the FAC statute was adopted, the Commission began approving FACs for Missouri's electric utilities: first for Aquila, Inc. (2007) (now Evergy Missouri West); then for Empire (2008); then Ameren Missouri (2009); and lastly, KCP&L (2015) (now Evergy Metro). Starting early-on, various parties have argued for more sharing. For years now, the Commission has concluded that FACs should continue to include the 95%/5% percent sharing mechanism the Commission implemented nearly initially. In fact, the Commission has rejected calls to impose more sharing on more than 15 separate occasions, as detailed in Schedule AMM-R1 to this testimony. The following is a sampling of Commission statements in support of retaining its 95%/5% percent sharing mechanism while rejecting calls to increase those shares:

- "A 95% pass through provides AmerenUE sufficient incentive to operate at optimal efficiency . . ." [rejecting an OPC attempt to impose 50%/50% sharing].[4]

[4] *Report and Order*, File No. ER-2008-0318, pp. 73-74 (citing five reasons that the 95/%/5% sharing was sufficient, including financial performance incentives for employees that would give them an incentive to minimize net energy costs, the Commission's use of historical instead of projected costs in FACs, which creates greater exposure to rising net energy costs for utilities, the Commission's heat rate/efficiency testing requirements, and the fact that having an FAC is a privilege, not a right, which itself gives utilities an incentive to properly manage net energy costs).

- Imposing a less favorable [to utilities] pass through provision "would signal to investors that [the utility] was less well regarded by . . ." the Commission.[5]
- "[C]hanging the sharing percentage without good reason to do so would lead investors to question the future of [the utility's] fuel adjustment clause."[6]
- "Most fuel adjustment clauses around the county [sic] provide for a 100 percent pass through of costs."[7]
- "MIEC and Public Counsel advocated for a revised sharing mechanism . . . However, the testimony those parties presented was based on little more than the opinions of their witnesses . . . No party presented any evidence that would indicate how the 95% sharing mechanism is working in practice . . . Certainly, no evidence was produced to show that [the utility] had acted imprudently. . ."[8]

Q. How would an even greater sharing percentage for Ameren Missouri compare to FACs of the other 97 utilities operating in non-restructured states?

A. A distinct minority of utilities have sharing of costs *at all.* From an investor standpoint, and from the standpoint of putting Missouri electric utilities on comparable footing with their peers, even the 5% share of net energy cost increases that Missouri

---

[5] *Id.*
[6] *Report and Order*, File No. ER-2011-0028, p. 85; *Accord Report and Order*, File No. ER-2010-0036, pp. 77-78 (Discussing concerns about overturning "regulatory stability" in Missouri, and increased investment risk caused if the Commission were to change sharing mechanisms given that investors value "certainty, fairness, stability and predictability").
[7] *Id.*, p. 75; *Report and Order*, File No. ER-2010-0036, p. 76 (same).
[8] *Id.*, pp. 76-77 (OPC's testimony in this case also consists of nothing more than unsupported opinions).

utilities must bear places them at a disadvantage. That disadvantage should not be exacerbated just because Ms. Mantle or OPC, or both, are willing to speculate that greater sharing would lead to greater incentive or for other reasons hold a philosophical belief that the sharing should be greater.

Q. Has Ms. Mantle offered any new justification for changing the sharing percentage?

A. Yes, Ms. Mantle has come up with this new "gamesmanship" theory that I have already fully debunked. Ms. Mantle also states that if the sharing percentage were changed this would provide the Company a greater earnings opportunity under certain scenarios. Finally, she suggests that the FAC Rider should have a sharing percentage that matches the percent of qualifying electric plant on which return and depreciation is deferred under the plant-in-service accounting ("PISA") statute,[9] that is, 85 percent.

Q. Is there any validity to any of these justifications?

A. No. Particular to this case, not only is there no evidence to suggest that Ameren Missouri has acted imprudently or that the 95%/5% sharing percentage isn't appropriate, but the $108 million NBEC reduction previously discussed demonstrates the Company's willingness and ability to reduce net energy costs when it can with the current sharing percentages. I want to reiterate that the Company would be taking the same diligent steps to reduce its net energy costs with no sharing at all.

As previously discussed, the Company does not establish normalized fuel costs independently. Unless Ms. Mantle is suggesting and can prove that the Company is

[9] Section 393.1400, RSMo.

dishonest and that the Staff is incapable of performing its duties, this justification is also flawed.

Regarding the justification that greater sharing could under certain scenarios lead to the Company having a greater earnings opportunity, OPC's math is nothing more than confirmation of the obvious: greater sharing would deprive customers of additional dollars of reductions in net energy costs and greater sharing would deprive Ameren Missouri of the ability to recover additional *prudently incurred* net energy costs if those costs increase.

Finally, the suggestion that the sharing percentage should necessarily match the percentage of qualifying electric plant on which deferrals are made through PISA fails to recognize the function of PISA (to remove a disincentive to invest) as compared to the intended function of a sharing mechanism in the FAC, as discussed in the rebuttal testimony of Ameren Missouri witness Tom Byrne.

The bottom line is that every "justification" put forth by OPC to increase Ameren Missouri's sharing percentage suffers from the same flaw from which past arguments in support of changing the sharing percentage have suffered: they amount to speculative opinions of individuals who have no experience in managing net energy costs, advanced by a party with demonstrated sustained hostility toward FACs.[10] They also lack any basis in facts showing that the utility has failed to prudently manage its net energy costs or that the existing 95%/5% sharing and the other incentives utilities possess to properly manage net energy costs (as recognized by the Commission) are in any way insufficient.

[10] As Ms. Mantle has admitted, OPC has been "very negative about fuel adjustment clauses from the beginning." Mantle Deposition, File No. ER-2014-0258, p. 230, ll. 8-11.

Q. Do you have any other observations on this issue?

A. Yes. We have repeatedly stated, and the Commission has repeatedly acknowledged, that having an FAC is a privilege, and not a right, and that this provides a powerful incentive for utilities to properly manage their net fuel costs.[11] Missouri is rather unique in that we have a statute mandating that we file a rate case and ask to continue our FAC at least every four years. The statute also mandates regular prudence reviews – we just completed our seventh prudence review. The bottom line is that utilities have plenty of incentives to properly manage the components in the FAC without any sharing at all. They could lose the FAC entirely or suffer prudence disallowances. Even without a single prudence disallowance, Ameren Missouri has failed to recover tens of millions of dollars of prudently-incurred net energy cost increases over the past several years, caused solely by the 5% sharing mechanism.[12] Had a 15% sharing percentage been in effect since inception of Ameren Missouri's FAC, that failure to recover prudently-incurred costs

[11] Ms. Mantle agrees. In her sworn deposition in File No. ER-2011-0028, she testified as follows: "**Q Okay. Do you agree if there is imprudence the Commission has the power and the obligation to disallow any costs related to the imprudence?** A Yes. **Q And would you agree that that is a powerful incentive for a utility to avoid imprudent behavior?** A Yes. **Q Would you agree with me that the use of a fuel adjustment clause in Missouri is a privilege and not a right for utilities?** A That is correct. **Q And isn't it true that the Commission can take away a utilities [sic] fuel adjustment clause if it believes the utility is misusing it?** A Yes. **Q And doesn't that also provide a powerful incentive for utilities to act reasonably and prudently with respect to their FACs?** A Yes." Lena Mantle Deposition, File No. ER-2011-0028, April 13, 2011, p. 44, l. 7 – p. 45, l. 18.

[12] The only controversy of any kind arose in File No. EO-2010-0255 because of the AEP and Wabash contracts entered into in 2009 after the ice storm that curtailed Noranda's smelter for about 14 months. Parties previously tried to argue that this showed some lack of incentive for the Company to properly manage its net energy costs with a FAC, and the Commission soundly rejected such a claim, stating: "The Commission did find that Ameren Missouri acted imprudently in that prudence review. However, the imprudence that the Commission found was related to Ameren Missouri's failure to flow revenue received from certain contracts through the fuel adjustment clause. Ameren Missouri had entered into those contracts in an attempt to replace a portion of the revenue it lost when production and the use of electricity was reduced at the Noranda aluminum smelter because of a January 2009 ice storm. Despite disagreeing with Ameren Missouri regarding the proper interpretation of a provision of the fuel adjustment clause tariff, the Commission did not find that Ameren Missouri had acted imprudently in deciding to enter into those replacement contracts. *In short, the Commission's decision in EO-2010- 0255 does not support the argument that Ameren Missouri needs a larger financial incentive within the fuel adjustment clause"* (emphasis added). *Report and Order,* File No. ER-2011-0028, pp. 82-83.

(which already totals more than $42 million with the 5% sharing) would have tripled, to more than $125 million.

As alluded to earlier, it is a very bad idea for the Commission to make changes to an important, mainstream mechanism like the FAC in the absence of a strong justification for making the change. Regulatory consistency is important to utilities as they plan and budget to provide service to their customers, and it is important to the investors on whom they depend for the huge sums of capital they need to do so. Ms. Mantle has been attempting to change the FAC and its sharing mechanism for years. Her latest attempt to radically re-shape the FAC should be rejected, as have the others.

Ms. Mantle's 85%/15% proposal in this case, like her prior 85%/15% proposal (made while she worked for the Staff) and her prior 90%/10% proposals (made in Ameren Missouri's last three rate cases), is nothing more than an unjustified experiment – an experiment for which no need has been shown.

V. <u>FAC TARIFF</u>

Q. Your direct testimony explained why it was necessary and appropriate to modify the currently-in-effect FAC tariff regarding transmission costs so that it is fully consistent with the Commission's prior rulings on that topic. Does that modification remain appropriate?

A. Yes, but as we responded to data requests (specifically Staff data request No. 383) on the topic, we discovered that the exact language that we had used requires a small modification. The reason for the small modification and the required modification itself is set out in the data request response, which I reproduce below[13]:

[13] Ameren Missouri Response to Staff Data Request No. 383.

Ameren Missouri has recognized that the proposed language in Rider FAC for factor T, requires modification to avoid potential confusion regarding charges recorded to account 565 for transmission charges received from AECI and KCP&L for firm network service to serve Ameren Missouri load under the respective interchange agreements.

The Company would propose modifying this section to read (edits in ***bold italics***):

> *1) One hundred percent of transmission service costs reflected in FERC Account 565 to either:
>
> a. transmit excess electric power sold to third parties to locations outside of MISO (off-system sales)(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule) or;
>
> b. transmit electric power on a non-MISO system ***(excluding those amounts associated with that portion of the Company's native load which is connected to a non-MISO system under a borderline, interchange or similar agreement)***,
>
> **2) One and 65/100 percent (1.65%) of transmission service costs reflected in FERC Account 565 directly attributable to Ameren Missouri's network transmission service (***including those amounts associated with that portion of the Company's native load which is connected to a non-MISO system under a borderline, interchange or similar agreement), and*** excluding (a) amounts associated with portions of Purchased Power Agreements dedicated to specific customers under the Renewable Choice Program tariff and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule),and
>
> *3) One and 65/100 percent (1.65%) of transmission revenues reflected in FERC Account 456.1(excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule).

These modifications should be included in compliance FAC tariffs filed after the Commission's order in this case is issued.[14]

---

[14] Please note that the Company's recommended percentage for inclusion in the FAC tariff is 1.65% and the Staff's Report recommended a slightly different percentage (1.35%). It is my understanding that the reason for the difference is simply one of timing because the Staff used a different period to determine loads and a different period for production cost modeling. However, once the true-up occurs it is my expectation that both of these percentages will change to some degree, but the Staff's and the Company's percentage should be very close or the same.

Q. For clarity, can you please address the Staff recommendation in the last bullet on page 150 of the Staff Revenue Requirement Report?

A. Yes. The Staff asks that the Company clarify that the only transmission costs and revenues that are included in the FAC are those that Ameren Missouri incurs for purchased power and off-system sales. By "purchased power," I take Staff to mean the so-called "true" purchased power discussed in prior Commission orders. I can confirm that yes, those are the only transmission costs being included.

VI. MR. ALLISON'S FAC RECOMMENDATIONS

Q. Sierra Club witness Avi Allison also recommends changes to the FAC process. What is the Company's position on his recommendations?

A. Most of his recommendations will be addressed by Mr. Byrne in his rebuttal testimony. I will, however, address the specific minimum filing requirement recommendations made by Mr. Allison. The Company does not oppose providing data that is relevant to review and discussion of unit commitment decisions for coal-fired units as part of its minimum filing requirements, or via the data request process, for each rate case. However, Mr. Allison is recommending that Ameren Missouri provide hourly data on all of its thermal generation units, including the Callaway Energy Center and its combustion turbine (peaker) fleet, which are not the subject of the unit commitment discussion. Further, the combustion turbine fleet already has a default commit status of "economic" in the MISO market. Moreover, he is apparently recommending such data be provided with each FAC rate adjustment filing – Mr. Byrne addresses why this would be inappropriate – and as some form of minimum filing requirement in FAC prudence reviews. With regard to prudence reviews, there are no "minimum filing requirements."

The Staff initiates and conducts the review and conducts discovery. Staff will request the data it needs as part of that process and has indicated that it intends to examine unit commitment practices in prudence reviews.

The only appropriate "minimum filing requirement" regarding such data would be limited to supplying the information in each rate case for the coal-fired units only, and not all thermal generation, for the reasons given above.

VII. <u>COAL UNIT OFFERED COST</u>

Q Ameren Missouri witness Dr. Todd Schatzki submitted testimony discussing generation offers in organized markets, and the appropriate use of marginal costs in constructing those offers. Does the Company use this economic approach in constructing unit offers?

A. Yes. Ameren Missouri relies on marginal costs, which reflect opportunity costs, in constructing unit offers – including those for its coal-fired units – to the MISO energy and ancillary services market. The offers are based on the economic principles discussed by Dr. Schatzki, in which costs reflect opportunity costs if the Company did not take specific actions – i.e., the opportunity cost of taking the action. As a result, offered costs frequently differ from accounting costs. Dr. Schatzki further explains that accounting costs provide an inappropriate basis for unit offers (unless by happenstance, the accounting and marginal costs were the same).

Q. Please provide examples of how marginal costs differ from direct accounting costs.

A. In addition to the fixed price fuel cost example provided by Dr. Schatzki, emission allowances and the price for regulating reserve service in the MISO market provide good examples.

Ameren Missouri receives an allocation of emission allowances. These allowances do not have a direct cost – the Company receives them from the government without charge. However, as noted by Sierra Club witness Ezra D. Hausman, PHD, in File No. ER-2014-0258, "(w)hether or not allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder."[15] If Ameren Missouri did not consider the economic value of the allowance – what it could be sold for – when it prepared its offer, and instead assumed the allowance cost was zero when setting its offers, the offers would be too low, the unit would be dispatched more often, and its output would be greater than economically justified. By accounting for emission allowances at the market price in its offers (which the Company in fact does), Ameren Missouri properly ensures that their value can be recognized.

Another area where opportunity costs must be accounted for in the MISO market is in the determination of the price for regulating reserve service. A generating unit which is providing regulating reserve service must necessarily hold back a portion of its generating capability to allow the unit to move up (i.e., be dispatched at a higher level) when instructed. The payment received for providing regulating reserve service includes the value of the foregone opportunity to sell energy for that portion of the unit's range that is held back.

[15] Hausman Direct, Sch. EDH-2, p. 5.

In addition to those two, another notable opportunity cost that must be accounted for is associated with Ameren Missouri's coal consumption, which is discussed later in this testimony.

Q. Has MISO itself addressed the appropriateness of basing generation offers on marginal costs that reflect opportunity costs?

A. Yes. The MISO Market Monitoring and Mitigation Business Practices Manual ("BPM") No. 009 discusses this topic extensively. Remember that it is the MISO Independent Market Monitor ("IMM") who is responsible for addressing inappropriate conduct related to 1) physical withholding, 2) economic withholding, 3) uneconomic production, and 4) uneconomic demand bids/uneconomic virtual transactions. The BPM makes clear that generating unit offers should be based on marginal costs that reflect opportunity costs.

Q. What does BPM No. 009 specifically say regarding these conduct tests?

A. The BPM explains that "reference levels" are used as benchmarks for performing conduct tests to make sure the generators are not manipulating the market with their unit offers. Specifically, reference levels are used in conjunction with various "conduct thresholds" as a means to detect economic withholding (not offering a unit when it should be offered; e.g., making offers that are artificially high) and uneconomic production (offering a unit when it shouldn't be offered; e.g., making offers that are artificially low[16]). Reference levels reflect a generating unit's (referred to by the IMM as a "Generating Resource") short-run *marginal costs*. Reference levels are typically calculated using <u>spot fuel prices</u>.

[16] Which is what Mr. Allison implies the Company has been doing, based on his flawed use of accounting costs.

Q. Starting at page 39 of his direct testimony, Mr. Allison says he evaluated the Company's offers against plant-level monthly average fuel costs and total production costs and ultimately claims that it is mathematically impossible for hourly incremental (marginal) production costs used for the Company's offers to be lower (or higher) than monthly average variable production costs in every hour of a given month. He then presents analysis intended to show that the units are offered below what he labels to be "production costs." Please comment.

A. As noted by Dr. Schatzki, Mr. Allison's tests are performed using the wrong cost basis, thus making his conclusions invalid. Mr. Allison suggests that "plant-level monthly average fuel costs and total production costs" should be the metrics used to validate the prudency of the Company's coal unit generation offers. However, neither of these comparisons represent the marginal economic costs used to construct the Company's offers.

Plant-level monthly average fuel costs and total production costs both include fixed costs that do not vary with changes in unit output. Costs that do not vary with changes in unit output are not appropriate for inclusion in the determination of the Company's incremental energy offer curve (the price at which a generation unit's output is offered at a given level of output).

The conclusion Mr. Allison presents from his comparisons only serves to mislead the Commission.

Q. Other than utilizing accounting costs, please provide an example of costs that Mr. Allison inappropriately includes in his review of offers.

A. Mr. Allison's comparison is flawed in that he is comparing average total fuel costs (in their entirety) to the Company's offers for incremental energy which are based on the cost of just a portion of the fuel used to operate the unit. The MISO market utilizes a three-part offer curve consisting of startup costs, no-load costs, and incremental energy costs. Startup costs are just what the name suggests – the cost to start the unit and bring it online. No-load costs are the hourly cost, expressed in dollars per hour, just to have the unit online but running at zero net output. Neither of these costs (startup and no-load) are properly included in an estimate of incremental energy costs as they don't vary with changes in unit output. For example, the fuel cost used by Mr. Allison includes the accounting cost of fuel oil at these plants, even though that fuel is only used for unit startup.

Startup and no-load costs are used in making decisions as to whether or not to commit a unit. They are not used to determine at what level the unit should be dispatched, once committed. Instead, the incremental energy offer curve is used to determine the dispatch level.

Q. Does Ameren Missouri account for no-load and startup costs in its unit commitment decisions?

A. Yes. The Company accounts for these costs in the 10-day forward-looking analysis discussed elsewhere in my testimony. The no-load cost is accounted for in the calculation of the anticipated daily margin. Startup costs are considered when the Company subsequently compares any negative margin periods to the costs to bring the unit off-line and are considered when deciding whether to bring an offline unit back online.

Q. You previously indicated that there are opportunity costs associated with Ameren Missouri's coal consumption. Please elaborate.

A. Ameren Missouri purchases its coal supply under fixed price, fixed quantity contracts. If Ameren Missouri fails to take the required, contracted quantities, the seller will charge Ameren Missouri the difference between the contract price and the spot market price at which the seller is able to sell the coal. As noted by Dr. Schatzki, this means that the Company's marginal cost of coal is not the accounting cost (relied on by Mr. Allison), but rather the spot price of coal at which the seller would mitigate the contract if the Company did not take delivery and burn the coal. The balance of the cost relative to the market price (i.e., the difference (above or below) between the accounting cost and the spot price cost) is not marginal.

Q. Does this mean your contracts are take-or-pay contracts?

A. No. Our contracts are not take-or-pay contracts. If they were, then the Company would be required to pay the full contract price for the fuel, regardless of whether or not it was received, and not just the difference between the contract price and market price.

Q. Would Ameren Missouri customers realize a greater benefit if the Company did not take receipt of the coal?

A. No. Most importantly, when units are dispatched by MISO based on the Company's incremental energy offer curves, which are based on marginal costs, the market revenue for that interval exceeds these marginal costs. This provides a benefit to our customers – a benefit which would be lost if we simply did not take receipt of the coal.

Additionally, customers would be further harmed from a supplier relationship standpoint if the Company did not take receipt of coal under an above-market fuel contract. The Company simply cannot choose to not accept delivery on a contract for economic reasons, and then expect the coal suppliers to willingly enter into an at-market contract for replacement fuel. It is logical to assume any future offers from the supplier would include a premium to address the risk of the Company's actions.

Q. How did Ameren Missouri's accounting cost of coal compare to the market price of coal in 2018?

A. At the beginning of 2018, the weighted average cost of the Company's coal inventory (based on delivery of coal under contracts entered into several years earlier) was higher than the 2018 spot market price. As the year progressed, and deliveries under preexisting, higher priced contracts were replaced with deliveries under the new, lower priced contracts I mentioned earlier in my discussion of the FAC, the accounting cost and market prices for coal trended much closer.

Q. For the years looked at by Mr. Allison, the accounting cost of the fuel was generally *higher* than the spot price. Would Ameren Missouri use accounting fuel costs to construct the coal unit offers if the contract prices were less than the market price?

A. No, and it would not be prudent to do so. The Company would continue to use the spot market price in its offers since that is its marginal cost. If the Company did otherwise, as Mr. Allison's claims suggest it should do, it would be offering its units at a lower price causing them to be committed and dispatched more than appropriate, which, based on Sierra Club's well-known stance regarding coal generation, would likely not be the result Sierra Club is looking for. And the Company's actions might be seen as consistent with conduct identified by MISO's IMM as anticompetitive – engaging in uneconomic dispatch.

Q. Do you have similar concerns with Mr. Allison's use of plant-level monthly average total production costs as a comparison to the Company's incremental energy cost curve?

A. Yes. Most obviously, since his total production cost is overwhelmingly made up of the average fuel costs, it necessarily suffers from the same flaws noted above for the fuel portion. The remaining portion – operations and maintenance expense – also contains costs which do not vary with changes in production. For example, staffing levels certainly do not change as a unit ramps up and down.

Simply put, if a cost does not vary with changes in production, it should not be considered in the construction of the incremental energy offer curve.

Q. Mr. Allison claims in his testimony that Ameren Missouri incurred "unnecessary operational losses" as a result of improper unit commitment decisions. Have you determined whether the units were properly committed and dispatched?

A. Yes, they were. When looking at these events using marginal costs, instead of the average accounting costs used by Mr. Allison, I have determined that in fact the commitment and dispatch of these units during those periods provided an incremental *benefit* of $781,786.

Q. Beyond the use of accounting costs, do you have other concerns with Mr. Allison's analysis of these events?

A. Yes. Mr. Allison's analysis relies upon data that was only known after the commitment decision was made and he then improperly uses this after-the-fact information (i.e., uses hindsight) to measure the prudency of the decision.

In essence, Mr. Allison is claiming that Ameren Missouri is not acting prudently in its unit commitment decisions.

Q. How do you respond?

A. Mr. Allison's suggestion is not backed up by the facts. In making commitment decisions, the Company's guiding principle is clear: sell energy from its units in the market when doing so benefits customers. The Company's evaluation of commitments and decommitments is based on a forecast of MISO prices. Like all forecasts, there is some forecast error when ultimately measured against actual results – that is, after-the-fact, actual prices inevitably turn out to be higher or lower than those forecasts. The fact that the Company's price forecast differed from actual prices is inherent to any forecasting estimate, but does not mean the Company has not been diligent in its unit commitment practices, nor does it make any of the actions it took imprudent, regardless of which cost basis is used to evaluate the results after-the-fact. And as noted earlier, the Company's commitment decisions in those instances when properly evaluated using marginal costs in fact produced positive margins for customers.

Q. Turning now to the specifics of the four instances examined by Mr. Allison, please respond to Mr. Allison's claim that the Company missed an opportunity to save $175,000 in net operational costs by extending the Sioux Unit 1 outage an additional 13 days?

A. As already thoroughly discussed, Ameren Missouri's process for evaluating commitment decisions is based on the marginal cost-based offers that reflect opportunity costs for the coal units. Using the actual MISO offer costs for this same timeframe, Sioux Unit 1 produced a positive benefit of $13,864; Mr. Allison's accounting cost-based calculation is simply wrong for the reasons discussed earlier. The $13,864 of incremental margin is inclusive of the incremental and no-load costs, and is also greater than the startup costs for this unit, which are approximately $12,000. The unit returned to service at 11:00 a.m. on February 20th. By the end of the 21st, the first full day of operation, the incremental margin from operations was $24,711. By the end of the 22nd, the second full day of operation, the margin from operations was $44,223. Both of these values are greater than the startup costs of the unit. At this point of operation, the decision to start the unit had already been made, and the next question facing the Company was whether to cycle the unit offline. Making that decision required a consideration of the marginal costs to decommit the unit.

Q. Please elaborate.

A. Sioux units have relatively low cold startup costs of approximately $12,000. However, operational experience has provided sufficient data to inform the Company that it is highly likely that the Sioux units will experience tube leaks when they are cycled offline. A tube leak repair generally lasts 5-7 days, and the Company spends approximately $75,000 to repair each of these leaks. These costs, which the Company considers de-commit costs, cannot be reflected in the MISO process due to its limitations, but are properly included in the Company's analysis when considering cycling coal units offline.

As a consequence, when the Company is considering cycling a Sioux unit offline, it must compare any projected negative margin to not only the $12,000 cost to restart, but also the $75,000 of additional operations and maintenance ("O&M") costs that will reasonably be expected to be spent on tube leak repairs specific to taking the unit offline, and must also consider any forecasted missed margins that otherwise would have been earned while that unit is on forced outage for the tube leak repairs. For the remainder of the commitment window identified by Mr. Allison, the unit's operational losses did not approach this $87,000 ($12,000 + $75,000) cycling hurdle rate. Consequently, the unit was left online.

Q. Mr. Allison claims that Sioux Unit 2 incurred $374,000 net operational losses, net of startup costs, from February 9th to March 4th, 2018. Do you agree that this value accurately represents the decision-making process?

A. No, it does not. Again, commitment decisions are based on marginal costs. Evaluating Sioux Unit 2 incremental margins utilizing marginal costs results in (a much smaller) negative margin of $50,713. However, as I discussed in my rebuttal of the Sioux Unit 1 claim, the cycling hurdle rate for a Sioux unit is approximately $87,000. Since the decision, based on a multi-day forecast, had already been made to commit the unit, customers were better off keeping the unit online instead of cycling the units off and on and incurring $87,000 of combined startup and O&M costs.

It was also not the case that the unit was consistently producing a negative margin every day of its commitment. This timeframe did contain seven continuous days of negative margins, based on marginal costs. During this time from February 4th to March 2nd, the unit had negative margins of $82,908.45, which is less than the estimated $87,000 decommit costs for a Sioux unit. However, it is likely that in the Company's decision-making process, forecasted prices did not reveal negative margins to this extent.

Q. Mr. Allison claims that Rush Island Unit 1 incurred approximately $167,000 in avoidable net losses in February 2018, based on an evaluation utilizing

accounting costs. How does this compare to the incremental margin calculated utilizing offers based on marginal costs?

A. From February 16th through March 9th, Rush Island Unit 1 produced positive incremental margins of $664,605 when properly evaluated using marginal costs. The total incremental margin would be reduced by the cost to start the unit initially. Margins through February 21st totaled $160,901, well in excess of the cost to start the unit.

Q. Again using accounting costs as the basis of evaluation, Mr. Allison claims that Labadie Unit 2 incurred $146,000 in unnecessary net operational losses from March 24th through April 1st. How does this margin compare to the incremental margin calculated when properly using marginal costs, including opportunity costs?

A. The same evaluation utilizing the Company's decision-making cost basis – marginal costs – resulted in $154,030 of positive incremental margins. Even excluding incremental margins from April 1st which were higher than previous days in this period, Labadie Unit 2 had positive margins of $99,973 – which is greater than the cost to start the unit.

VIII. COAL UNIT SELF-COMMITMENT

Q. Mr. Allison claims that "Ameren's practice of self-committing its coal units means that the extent to which those units operate is largely ungoverned by market forces."[17] Do you agree with this claim?

A. No, I do not. The commitment decisions for Ameren Missouri's coal generation are based upon economic analysis of the market. This analysis is more comprehensive and inclusive of relevant factors for Ameren's long-lead time units than the

[17] Allison Direct, p. 29, ll. 6-7.

MISO commitment process. There are risks and costs that the MISO process does not incorporate, which are properly considered by Ameren Missouri in making its unit commitment decisions. To suggest that the Company's consideration of these market risks and costs results in commitments "ungoverned by market forces" is nonsense. Mr. Allison's description as "ungoverned by market forces" also chooses to ignore the role of the MISO IMM. As stated by Staff in the Commission's unit commitment docket, File No. EW-2019-0370, "the MISO-IMM indicated that market forces will likely discipline the market. Therefore, the MISO-IMM looks for abuses of power and whether behavior is justified."[18]

Q. What flaws regarding the MISO unit commitment process require the Company to self-commit units?

A. The MISO process used in its day-ahead market only analyzes the 24-hour period of the next calendar day. Ameren Missouri discussed this issue in File No. EW-2019-0370, saying "However, making a unit commitment decision merely by looking at one 24-hour period is not appropriate and would harm customers. This is because the market participant must look past the next 24 hours and assess whether this one-day revenue shortfall is projected to persist for a prolonged period of time such that the cumulative shortfalls would exceed the total of the expected foregone margins, the cost to restart the unit, and the risk of significant maintenance and capital expenses arising from cycling the unit if it is committed and then decommitted and then committed again."[19] Those flaws in MISO's process still exist.

[18] Staff Report, File No. EW-2019-0370, p. 9 (Aug. 23, 2019).
[19] Ameren Missouri's Response to Order Opening an Investigation of Missouri Jurisdictional Generator Self-Commitments and Self Scheduling and to Order Directing Comments, File No. EW-2019-0370, p. 5 (July 8, 2019).

Another consequence of the process' limited forward period of analysis is that market participants do not have a clear means of informing MISO of what the cost to shut down (decommit) a unit is expected to be. Such costs include not only the cost to restart the unit discussed above, but also foregone expected positive margins during minimum downtimes, and increases in maintenance and capital costs related to unit cycling. In general, Ameren Missouri utilizes a must run commit status for those units whose operating characteristics, such as high cost to restart, expected increase in forced outages if the units are not placed in must run commit status, and maintenance and capital costs due to unit cycling, warrant such a designation. Ameren Missouri witness Jim Williams addresses the costs of cycling these units in his rebuttal testimony.

Q. How does the minimum downtime of a unit factor into Ameren Missouri's commitment analysis?

A. Minimum downtime refers to the amount of time that a unit must remain offline after it is taken offline. It is not available for commitment during this period, even if commitment would otherwise be economic. This means that if a unit's minimum downtime is three days, decommitting the unit based only on the next day's MISO model results could mean that the unit will forego margins for the following two days after that first negative margin market day, when it remains shut-down. Once again, by looking beyond the 24-hour time limit of the MISO process, we can include the projected margin on those days in our analysis.

Q. Would Ameren Missouri's commitment practices for its coal units change if the MISO process solved for multiple days and recognized multi-day minimum runtimes and downtimes?

A. Yes. If the MISO were to adopt these changes, in a financially binding manner – which Ameren Missouri supports – the Company's use of the must-run commitment status for its coal units would be significantly reduced. But today – and during the period examined by Mr. Allison – MISO's process meant that self-commitment was the proper commitment status for these units.

Q. Is the concept of multi-day unit commitments being considered by the MISO and the Southwest Power Pool ("SPP")?

A. Yes, both regional transmission organizations have this issue on their market roadmaps. However, SPP has already publicly discussed some analysis related to changing its market format. The SPP-IMM's whitepaper titled "Self-Committing in SPP Markets: Overview, Impacts, and Recommendations," evaluates self-commitment under current market rules and assumptions consistent with a multi-day dispatch algorithm. The whitepaper states: "however, as we presented in our simulations, simply eliminating self-commitment without any additional changes could result in an increase in total production costs. This would not necessarily be an improvement when compared to today's results. However, when lead times were shortened to reflect an additional day in the market optimization and self-commitment was eliminated, producers were paid more and production costs declined."[20]

Q. Mr. Allison also claims "it appears that Ameren maintains a default presumption that its units should remain online unless there is overwhelming evidence to the contrary." Do you agree?

[20] Issued by SPP's Market Monitoring Unit in December, 2019 (see page 42).

A. Ameren Missouri approaches each asset management decision as unique and considers the appropriate generation costs for the situation. Each day the Company performs a 10-day forward-looking study of market and operational conditions. To be clear, the Company considers cycling coal units offline for periods briefer than 10 days. However, the economics of the coal units in the Ameren Missouri generation fleet quite frequently dictate that they should remain committed in the market. These economics, particularly for the Labadie and Rush Island units, include a low marginal cost of production (due to low fuel costs and better heat rates) and a high cost to restart. The Sioux units also have a marginal cost that is frequently in-the-money when compared to MISO day-ahead prices.

The Company's daily process is a prospective, operational view of commitment decisions designed to produce prudent decisions to the benefit of the Company's customers. That process utilizes specialized models to evaluate unit profitability on a daily basis, allowing Ameren Missouri to plan around the limitations in MISO's process, which as explained earlier, only analyzes the next 24 hours.

Q. Would Ameren Missouri apply this same 10-day analysis perpetually, even if units were routinely losing money each day, just not enough money to exceed the cycling hurdle rate, as Mr. Allison suggests?

A. No. Ameren Missouri also utilizes a longer-term planning model, the Prosym production cost model utilized by the Company to establish NBEC in this case, which should identify when units will be out of the money for extended periods. The Company will also perform ad hoc analysis when it is identified that short-term trends may persist for longer periods.

Q. Mr. Allison suggests that Ameren Missouri does not apply the same rigor for a decision to bring a unit back online as it does for decommitting a unit. Do you agree?

A. No. As previously stated, Ameren Missouri approaches each asset management decision as unique and considers the appropriate generation costs for the situation. When analyzing a decision to bring a unit online, the Company utilizes the process previously identified to evaluate the forecasted profitability of the unit, and recovery of startup costs over multiple days as part of that consideration. If that process, whether after an outage or not, indicates that the unit should not be committed, then it won't be committed.

Q. Mr. Allison recommends that Ameren Missouri should retain the analysis underlying its unit commitment decisions. Does the Company object to this recommendation?

A. The Company does not object to retaining the analysis used in making its unit commitment decisions and is already actively working to amend its analysis processes to allow for retention of this data. The Company has a robust unit commitment process, and agrees that review of this process should be as transparent as possible.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren	)	
Missouri's Tariffs to Decrease Its Revenues for	)	File No. ER-2019-0335
Electric Service.	)	

AFFIDAVIT OF ANDREW MEYER

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

COMES NOW Andrew Meyer, and on his oath declares that he is of sound mind and lawful age; that he has prepared the foregoing *Rebuttal Testimony*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Andrew Meyer
Andrew Meyer

Subscribed and sworn to before me this 21st day of January, 2020.

Geri A. Best
Notary Public

My commission expires:

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

Non-Utility FAC Sharing Mechanism
Proposals Other than 95%/5%
(95%/5% Adopted/Approved
in Each Instance)

Case Number	Utility	Party	Sponsoring Witness	FAC Sharing Mechanism Proposal
ER-2007-0002	Ameren Missouri	AARP	Ronald Binz (Nancy Brockway)	Sharing bands
		The Commercial Group	Kevin Higgins	50/50
		MIEC	Maurice Brubaker	80/20 with deadband and sharing bands
ER-2007-0004	Aquila	AARP	Nancy Brockway	50/50
		SIEU, AG-P & FEA	Donald Johnstone	50/50
ER-2008-0093	Empire	MIEC	Maurice Brubaker	95/5 with deadband and sharing bands
		Staff	Lena Mantle	60-80% pass through with 70 mid-point
		OPC	Ryan Kind	60/40
ER-2008-0318	Ameren Missouri	MIEC	Maurice Brubaker	80/20
		State of Missouri	Martin Cohen	80/20 Alternate: 85/15 for cost increases 95/5 for cost decreases
		OPC	Ryan Kind	50/50
ER-2010-0036	Ameren Missouri	Staff	John Rogers David Roos	95/5
		MIEC	Maurice Brubaker	80/20
		OPC	Ryan Kind	80/20
ER-2010-0130	Empire	Staff	Matt Barnes	95/5

Case Number	Utility	Party	Sponsoring Witness	FAC Sharing Mechanism Proposal
ER-2010-0356	KCPL-GMO	Staff	David Roos	75/25
		OPC	Ryan Kind	75/25
ER-2011-0004	Empire	Staff	Matt Barnes	85/15
		OPC	Ryan Kind	85/15
ER-2011-0028	Ameren Missouri	Staff	Lena Mantle	85/15
		OPC	Ryan Kind	85/15
ER-2012-0166	Ameren Missouri	Staff	Lena Mantle	85/15
		MIEC	None	85/15
		AARP/CCM	None	50/50
ER-2012-0175	KCPL-GMO	Staff	Matt Barnes	85/15
ER-2012-0345	Empire	Staff	Matt Barnes	85/15
ER-2014-0258	Ameren Missouri	OPC	Lena Mantle	90/10
		CCM	None	50/50
ER-2014-0351	Empire	OPC	Lena Mantle	90/10
ER-2014-0370	KCPL	Staff	Dana Eaves	95/5
		OPC	Lena Mantle	50/50
		MECG	Michael Brosch	95/5 (or anything higher than 0)
ER-2016-0023	Empire	Staff	David Roos	95/5
ER-2016-0156	KCPL-GMO	Staff	Matt Barnes	95/5
		OPC	Lena Mantle	90/10

Case Number	Utility	Party	Sponsoring Witness	FAC Sharing Mechanism Proposal
ER-2016-0179	Ameren Missouri	OPC	Lena Mantle	90/10
ER-2016-0285	KCPL	OPC	Lena Mantle	90/10
		OPC	Lena Mantle	90/10