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| **Exhibit No.:** | ______________ |
| **Issue(s):** | Fuel Adjustment Clause (FAC) |
| **Witness/Type of Exhibit**: | Mantle/Surrebuttal |
| **Sponsoring Party**: | Public Counsel |
| **Case No**.: | ER-2019-0335 |

# SURREBUTTAL TESTIMONY

# OF

# LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

**UNION ELECTRIC COMPANY**
**D/B/A AMEREN MISSOURI**

FILE NO. ER-2019-0335

February 14, 2020

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

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

**AFFIDAVIT OF LENA M. MANTLE**

| | | |
|---|---|---|
| **STATE OF MISSOURI** | **)** | |
| | **)** | **ss** |
| **COUNTY OF COLE** | **)** | |

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena M. Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M. Mantle
Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 14th day of February 2020.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Cole County
Commission #15637121

Tiffany Hildebrand
Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2023.

**SURREBUTTAL TESTIMONY**

**OF**

**LENA M. MANTLE, P.E.**

**UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI**

**CASE NO. ER-2019-0335**

**Q. What is your name?**

A. Lena M. Mantle.

**Q. Are you the same Lena M. Mantle who provided both direct and rebuttal testimony in this case?**

A. Yes, I am.

**Q. What is the purpose of your surrebuttal testimony?**

A. The purpose of this surrebuttal testimony is to respond to the rebuttal testimony of Ameren Missouri witnesses Andrew Meyer and Tom Byrne and Public Service Commission Staff ("Staff") witness Lisa Wildhaber by showing the Commission that the current sharing mechanism of the FAC, which was set with no supporting testimony, should be replaced with a sharing mechanism that better incentivizes prudent decisions and that the Missouri General Assembly recently approved for that purpose.[1]

**Q. What is your recommendation regarding the fuel adjustment clause ("FAC") incentive mechanism?**

A. As I previously laid out in my direct testimony, I recommend that the Commission modify Ameren Missouri's FAC by changing the sharing mechanism of the difference between the actual FAC costs incurred and the base FAC costs as set in

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[1] Senate Bill 564 was approved by the 99th General Assembly. This is the first general rate case before this Commission since this bill became effective on August 28, 2018.

this case to be recovered/returned to 85% from/to the customers and 15% from/to Ameren Missouri ("85/15 sharing").

**Q. What is Ameren Missouri's response to OPC's recommendation?**

A. Ameren Missouri argues that the FAC sharing mechanism should remain as it currently is with Ameren Missouri's incentive to improve the efficiency and cost effectiveness of its fuel and purchased power activities only being five percent of any increases or decreases to its FAC costs ("95/5 sharing").[2]

**Q. What is the Staff's response to OPC's recommendation?**

A. Staff provided the following one sentence rebuttal to my recommendation in the rebuttal testimony of Lisa Wildhaber: "It is Staff's position that no party has provided sufficient evidence warranting a change in the current sharing percentage."[3]

**Q. What is your response to the rebuttal testimony of Staff and Ameren Missouri regarding the FAC incentive mechanism?**

A. There is a solid basis for the 85/15 sharing mechanism I recommend, while the 95/5 sharing mechanism that Ameren Missouri and Staff recommend is arbitrary and has no support. Therefore, the Commission should adopt my 85/15 sharing mechanism for Ameren Missouri and consider the same for all other electric utilities moving forward.

**Q. Would you explain further?**

A. The FAC enabling statute, section 386.266 RSMo. allows the Commission to include in the FAC "factors designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and

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[2] Rebuttal testimonies of Ameren Missouri witnesses Andrew Meyer (pages 9-16) and Tom Byrne (pages 54-56).

[3] Page 8.

purchased-power procurement activities." It does not provide what that incentive should be. In the first rate case before the Commission in which the Commission granted an FAC,[4] there were many proposals for what such an incentive mechanism should look like and the parties provided support for each of their proposals. Some were drawn from experience with other state jurisdictions. Some were independent proposals. In its *Report and Order* in that case, the Commission found that after-the-fact prudence reviews were not sufficient and determined that an incentive mechanism was needed[5] but it did not choose any of the proposed incentive mechanisms set before it. Instead it set the incentive mechanism at 95/5;[6] a ratio neither proposed nor supported by any party in the case. As provided in the rebuttal testimony of Ameren Missouri witness Andrew Meyer, various parties, including Staff and OPC, have proposed changes to this sharing since that first case. However, this arbitrarily set mechanism has been used in all FACs since that rate case.

Ten years later, Senate Bill 564 was introduced to the Missouri General Assembly. As introduced, a portion of that bill, section 393.1400 RSMo., required all (100%) depreciation expense and associated return of certain capital investments to be deferred for recovery from customers (plant in-service accounting or "PISA"). However, the General Assembly did not agree with this 100% recovery as proposed and ultimately determined that an incentive mechanism was needed. Moreover, the final bill the General Assembly approved does not allow an arbitrary setting of an incentive mechanism for recovering costs. Instead, the General Assembly determined that an 85/15 sharing mechanism was appropriate. As the Commission described in its *Report and Order* in File No.

[4] ER-2007-0004, *In the Mater of the Tariffs of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks MPS and Aquila Networks – L&P Service Areas*.
[5] ER-2007-0004, *Report and Order*, page 54.
[6] Id, page 55.

EA-2018-0202, the eighty-five percent limitation was added to the legislation by the General Assembly during the legislative process as a "legislative compromise intended to maintain some regulatory lag to protect ratepayer interest." [7]

**Q. Is the sharing mechanism defined in the statute tied to increase and decreases in costs like the FAC sharing mechanism?**

A. No, it is not. The 85/15 sharing mechanism of plant in-service cost is a straight 85/15 sharing. Electric utilities that request PISA will absorb 15 percent of the **<u>total</u>** costs until the next rate case. The OPC's 85/15 sharing proposal for the FAC, on the other hand, is to have an 85/15 split of only the **<u>additional</u>** fuel costs. With the FAC sharing mechanism OPC is proposing, costs could increase 30 percent and Ameren Missouri would absorb less than four percent of the **<u>total</u>** FAC costs. This is shown in the table below.

| | PISA | FAC |
|---|---|---|
| Base set in rate case | $0 | $100,000 |
| Actual Cost [8] | $130,000 | $130,000 |
| Recoverable from Customers | $110,500 | $125,500 |
| Percent recoverable | **85%** | **97%** |

**Q. This table shows a big difference in the percent recoverable between the PISA's 85/15 sharing (85%) and the FAC's 85/15 sharing (97%). Why are you just proposing the 85/15 be applied to the differences in FAC costs instead of the entire fuel costs?**

A. As Ameren Missouri witnesses Byrne and Meyer testified in their rebuttal testimony,[9] PISA applies to capital expenditures and the FAC applies to expenses.

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[7] EA-2018-0202, *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Convenience and Necessity Authorizing it to Construct a Wind Generation Facility*, <u>Findings of Fact</u>, page 6, paragraph 8.

[8] PISA costs defined in this table as depreciation and return of and on investment for plant.

I would take that one step further by saying that the PISA expenditures are completely under Ameren Missouri's control. It can decide timing and the amount of the expenditures. Ameren Missouri has less control over its FAC costs. The FAC costs are largely dependent upon the Mid-Continental Independent System Operator ("MISO") markets, fuel prices, and the load demands of the customers.

**Q. Are you saying that Ameren Missouri has no control over its FAC costs?**

A. No. However, Ameren Missouri does have some influence on its FAC costs which I believe the General Assembly that allowed for an incentive in Section 386.266 RSMO. For this reason the Commission should provide an incentive for Ameren Missouri to be efficient in its FAC expenditures. For example, Ameren Missouri is in complete control of when it offers its generation into the MISO energy market. With the current FAC approved by the Commission, there is very little impact to Ameren Missouri from offering a generation plant into the market when it is not cost effective to do so since Ameren Missouri will recover almost 100% of the fuel costs of running a plant regardless of whether or not market prices are greater than the costs. This leads to the self-scheduling that Sierra Club witness Avi Allison described in his direct testimony in this case which is attached as Schedule LM-S-1 to this testimony.

**Q. Would changing the sharing mechanism to 85/15 remove all incentive for inefficient self-scheduling?**

A. No, it would not. As shown above, Ameren Missouri would still recover almost all of its fuel costs including a large percentage of the increased costs it incurred by self-scheduling. It would however increase the cost to Ameren Missouri for

[9] Rebuttal testimony of Tom Byrne, page 56; Rebuttal testimony of Andrew Meyer, page 14.

inefficient scheduling of power plants and decrease the burden of inefficient choices by Ameren Missouri on its customers.

**Q. Could inefficient scheduling of generation resources be brought before the Commission in FAC prudence review cases?**

A. It could, but it has not been reviewed carefully by Staff or OPC in past prudence audits. However, imprudence would be nearly impossible to show given Ameren Missouri overwrites the analysis it conducts to inform its unit commitment decisions as provided in Ameren Missouri's response to Sierra Club data request 1.24 attached to this testimony as Schedule LM-S-2.

**Q. Ameren Missouri witness Andrew Meyers testifies that your proposed sharing mechanism would deprive customers of reductions in net energy costs. How do you respond to this testimony of Mr. Meyers?**

A. Mr. Meyers is correct. In the occasional situation in which the actual costs fall below the costs included in the FAC net base energy cost, the customers would indeed see less of the decrease in costs. However, history has shown that of the 32 FAC rate changes, the actual FAC costs have been below the FAC base only nine times returning only $76.4 million to the customers. This is less than one tenth of the $881 million of charges Ameren Missouri has billed its customers through the FAC since its inception. In contrast, Ameren Missouri has absorbed only $42 million (0.67%) of its FAC costs of $6,338 million it has incurred since it received a FAC. A complete listing of the FAC amounts for each FAC accumulation period as provided on Commission approved tariff sheets is attached as Schedule LM-S-3 to this testimony.

**Q. Would you summarize your position regarding your proposed change to the FAC sharing mechanism?**

A. In 2018, the General Assembly set a firm basis for an appropriate incentive mechanism for electric utilities. This is the first rate case after the effective date of section 393.1400 RSMo. in which a change to the FAC could be enacted.[10] Based on my experience with the FAC, and knowledge of the decisions the company must make to procure fuel and purchased power, an 85/15 sharing is also an appropriate incentive for Ameren Missouri's FAC mechanism. Therefore, my recommendation to use an 85/15 sharing mechanism for the FAC has a firm basis and should be adopted by this Commission.

**Q. Does this conclude your surrebuttal testimony?**

A. Yes, it does.

[10] Section 386.266.5 prevents the Commission from modifying the FAC outside a general rate case.

| | |
|---|---|
| Exhibit No.: | |
| Issues: | Revenue Requirement |
| Witness: | Avi Allison |
| Type of Exhibit: | Direct Testimony |
| Sponsoring Party: | Sierra Club |
| Case No.: | ER-2019-0335 |
| Date Testimony Prepared: | Dec. 4, 2019 |

# BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

## FILE NO. ER-2019-0335

## REVENUE REQUIREMENT

## DIRECT TESTIMONY

## OF

## AVI ALLISON

## ON BEHALF OF SIERRA CLUB

**December 4, 2019**

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

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

**AFFIDAVIT**

SARAH BRUNNER
Notary Public
State of Washington
Commission # 205078
My Comm. Expires Jan 19, 2023

STATE OF Washington )
) ss.
COUNTY OF King )

Avi Allison, first being sworn on his oath, states:

1. My name is Avi Allison, and I am a Senior Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.
2. Attached hereto and made part hereof for all purposes in my Revenue Requirement Direct Testimony on behalf of Sierra Club consisting of 47 pages and 28 exhibits, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.
3. I hereby swear and affirm that based upon my personal knowledge, the facts stated in the direct testimony are true. In addition, my judgment is based upon my professional experience, and the opinions and conclusions stated in the Revenue Requirement Direct Testimony are true, valid, and accurate.

Avi Allison

SUBSCRIBED TO AND SWORN TO before me this 4th day of December, 2019, by Avi Allison.

Notary Public

My commission expires: Jan 19, 2023

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AA-D-4. *United States v. Ameren Missouri*, Judgment, Doc. #: 1123, U.S. District Court Eastern District of Missouri, Case No. 4:11-cv-77-RWS (Sept. 30, 2019).
AA-D-5. *United States v. Ameren Missouri*, Memorandum Opinion and Order, Doc. #: 1122, U.S. District Court Eastern District of Missouri, Case No. 4:11-cv-77-RWS at 113 (Sept. 30, 2019).
AA-D-6. *United States v. Ameren Missouri*, Memorandum Opinion and Order, Doc. # 852, U.S. District Court Eastern District of Missouri. No. 4:11-cv-77-RWS. (Jan. 23, 2017).
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AA-D-20. Lazard, Lazard's Levelized Cost of Energy Analysis – Version 10.0 (Dec. 2016).
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AA-D-25. Ameren Missouri, IRP Update, Spring 2019.
AA-D-26. NIPSCO, 2018 IRP at 56 (Oct. 31, 2018).
AA-D-27. MISO, Business Practices Manual No. 002 – Energy and Operating Reserve Markets, Version 19 (Oct. 15, 2018).
AA-D-28. Missouri Public Service Commission File No. ER-2020-0143, Order Directing Notice, Setting Intervention Deadline and Directing Staff Recommendation (Nov. 25, 2019).

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## 1. Introduction and Purpose of Testimony

**Q Please state your name and occupation.**

A My name is Avi Allison, and I am a Senior Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

**Q Please describe Synapse.**

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

**Q Please summarize your work experience and educational background.**

A At Synapse, I provide consulting and research services on a wide range of issues related to the electric industry. My areas of focus include resource planning, power plant economics, rate design, economic impact analysis, and regional capacity markets. I have provided consulting services for a variety of public sector and public interest clients including the U.S. Environmental Protection Agency, the Michigan Public Service Commission, the Michigan Agency for Energy, the New York State Energy Research and Development Authority, the Rhode Island Office of Energy Resources, the Efficiency Maine Trust, the Maine Office of the Public Advocate, the California Department of Justice, the Washington State Office of the Attorney General, the Colorado Energy Office, Sierra Club, Natural Resources Defense Council, and other organizations.

I have provided testimony in resource planning, rate case, and power cost dockets in Arizona, Arkansas, Indiana, Michigan, and Washington.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in economics from Columbia University. A copy of my current resume is attached as Exhibit AA-D-1.

**Q On whose behalf are you testifying in this case?**

A I am testifying on behalf of Sierra Club.

**Q Have you testified previously before the Missouri Public Service Commission?**

A No, I have not.

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

A The purpose of this testimony is to evaluate the economics of the coal fleet of Union Electric Company d/b/a Ameren Missouri (Ameren or the Company). Specifically, I assess (1) the overall economic status of Ameren's coal units from a resource planning perspective and (2) Ameren's operational coal unit commitment and dispatch practices.

**Q Please identify the documents upon which you base the opinions presented in your testimony.**

A My findings rely primarily upon the testimony, exhibits, and discovery responses of Ameren witnesses. I also rely to a limited extent on external documents such as Midcontinent Independent System Operator ("MISO") materials and industry publications.

## 2. Findings and Recommendations

**Q Please summarize your findings.**

**A** My primary findings include the following:

1. **Each of Ameren's Labadie, Rush Island, and Sioux coal units lost more than $20 million relative to the market over the past three years.** Using Ameren data, I calculate that these units collectively incurred $347 million in net losses relative to marginal market replacement over the period from 2016 through 2018. While these historical losses relative to the market do not by themselves indicate that these units should be retired, they highlight the need for rigorous economic retirement assessments of each unit.

2. **Ameren's recent and planned coal plant investment decisions do not sufficiently account for the major environmental compliance costs facing the Rush Island and Labadie plants.** Ameren is likely to have to incur approximately $1 billion in environmental compliance costs to keep operating these plants beyond 2024. Yet the Company has neglected to evaluate the reasonableness of continuing to invest in its coal plants in light of these financial risks. Ameren appears to not even be sure whether its recent capital expenditures at these plants would be necessary if the plants were to retire prior to 2025.

3. **Ameren's 2017 Integrated Resource Plan ("IRP") coal unit analyses cannot be relied upon to support continued investment in Ameren's coal units.** Those analyses relied on a series of assumptions that were unreasonably biased in favor of the coal units at the time of the assessment and appear even less reasonable today.

4. **Ameren's coal unit commitment practices have led it to incur unnecessary net operational losses on behalf of ratepayers.** In 2018, Ameren "self-committed" each of the Labadie, Rush Island, and Sioux units in the MISO energy market in more than 99 percent of the hours in which those units were not on outage. I estimate that on at

least four occasions in 2018 Ameren inappropriately self-committed its coal units in a way that led the Company to incur net operational losses. Ameren's explanations for its self-commitment practices do not justify these losses. In addition, Ameren's practice of overwriting the analyses it conducts to inform its unit commitment decisions makes review of those decisions and the Company's analyses unnecessarily challenging.

5. **Ameren consistently offers its coal units into the MISO energy market at prices that are below their variable costs of production.** This practice likely contributes to net operational losses incurred by those units.

6. **Ameren's current Fuel Adjustment Clause ("FAC") process does not allow for sufficient review of the Company's commitment and dispatch decisions.** The current process does not provide Commission Staff or other stakeholders with sufficient time to assess Ameren's operational practices. In addition, the frequency of Ameren's FAC filings may not enable efficient review of Ameren's unit commitment and dispatch practices.

**Q Do you have any recommendations to offer the Commission?**

A Yes. Based on my findings, I offer the following recommendations:

1. The Commission should not allow the recovery of capital costs incurred at the Rush Island, Labadie, or Sioux plants in 2018 or later until Ameren has presented sound analyses that justify those investments in the face of major environmental compliance costs and declining renewable resource costs.

2. The Commission should require Ameren to present rigorous economic assessments of alternative near-term retirement dates for each of the Rush Island, Labadie, and Sioux units by the end of 2020. These forward-looking assessments should be presented in a docketed proceeding to enable full Commission oversight and stakeholder review.

They should incorporate up-to-date assumptions regarding market prices, resource costs, and environmental compliance costs.

3. The Commission should disallow the recovery of operational costs incurred through the uneconomic commitment and dispatch of Ameren's coal units. I estimate that Ameren incurred at least $861,000 in unnecessary net operational losses in 2018.

4. The Commission should require Ameren to retain the analyses underlying its unit commitment decisions for a period of at least two years. These analyses should clearly specify the costs and revenues that are accounted for within the analyses.

5. The Commission should revise its requirements regarding Ameren's FAC process to enable more thorough and efficient review of the Company's unit commitment and dispatch practices. I recommend that the Commission pursue this goal by providing Staff and other stakeholders with more time to respond to Ameren's FAC adjustment filings and/or setting minimum FAC filing requirements that better enable Staff and stakeholders to review unit commitment and dispatch practices. In addition, I recommend that the Commission structure the FAC process to enable annual, rather than triannual, review of unit commitment and dispatch practices.

## 3. AMEREN'S COAL UNIT PLANS AND PROPOSALS

**Q Which Ameren generating units does this testimony focus on?**

**A** This testimony focuses on the economics of the eight coal units that Ameren plans to continue operating beyond 2022. These include Labadie Units 1, 2, 3, and 4; Rush Island Units 1 and 2; and Sioux Units 1 and 2.[1]

[1] Ameren's other remaining coal units include Meramec Units 3 and 4. These units are slated for retirement in September 2022.

**Q What are Ameren's planned retirement dates for each of these units?**

A Table 1 summarizes Ameren's planned retirement dates for the Labadie, Rush Island, and Sioux coal units. Ameren plans to continue operating each of these units through at least 2033. Ameren plans to operate all four Labadie units beyond 2035 and plans to operate both Rush Island units through 2045.

**Table 1. Ameren coal unit retirement date assumptions**

| Plant | Unit | Retirement Date |
|---|---|---|
| Labadie | 1 | 2036 |
| Labadie | 2 | 2036 |
| Labadie | 3 | 2042 |
| Labadie | 4 | 2042 |
| Rush Island | 1 | 2045 |
| Rush Island | 2 | 2045 |
| Sioux | 1 | 2033 |
| Sioux | 2 | 2033 |

*Source: Ameren Response to Data Request No. SC 1.12b.*

**Q What is the basis for Ameren's assumed coal unit retirement dates?**

A Ameren's coal unit retirement date assumptions are based on testimony presented by Ameren witness Larry Loos in the Company's 2014 rate case.[2] That testimony focused primarily on the engineering life of Ameren's coal units and concluded that each remaining unit should

[2] Ameren Response to Data Request No. SC 1.12c (*see* Ex. AA-D-2).

retire at an age of between 61 and 70 years.[3] The planned Labadie, Rush Island, and Sioux retirement dates do not appear to be grounded in rigorous economic analysis.

**Q What types of coal unit expenses is Ameren seeking to recover through this rate case?**

A Ameren is seeking recovery of ongoing capital expenses and operations and maintenance (O&M) expenses at its coal units. In addition, Ameren is requesting the continuation of its FAC, which affects recovery of fuel costs incurred at its coal units.[4] This case therefore is connected to the reasonableness of both Ameren's resource planning process (which relates to the prudence of capital and fixed O&M costs) and the Company's unit commitment and dispatch process (which affects the prudence of variable O&M and fuel costs).

**Q What test year is the Company proposing to use to set the revenue requirement in this rate case?**

A Ameren's proposal is based on a 2018 test year, with pro forma adjustments to account for the true-up of various items through the end of 2019.[5]

**Q What levels of coal plant capital and O&M expense are included in the Company's test year spending?**

A Table 2 summarizes the Company's test year capital and O&M expenses at the Labadie, Rush Island, and Sioux plants. Ameren's test year spending includes a total of $219 million in capital expenses and more than $150 million in O&M expenses at these three plants.

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[3] AA-D-3, Direct Testimony of Larry W. Loos on Behalf of Ameren, Missouri Public Service Commission File No. ER-2014-0258 (July 3, 2014).

[4] Direct Testimony of Marci L. Althoff on Behalf of Ameren at 2.

[5] Direct Testimony of Laura Moore on Behalf of Ameren at 3.

**Table 2. Ameren coal plant 2018 test year capital and O&M expense**

| Plant | Capital Expense ($Million) | O&M Expense ($Million) |
|---|---|---|
| Labadie | $132.1 | $69.4 |
| Rush Island | $66.8 | $41.3 |
| Sioux | $20.5 | $43.0 |
| ***Total*** | ***$219.4*** | ***$153.7*** |

*Source: Ameren Response to Data Request No. SC 1.3.*
*Notes: Excludes Meramec plant, which includes coal and gas units.*

## 4. Economic Status of Ameren Coal Units

**Q Please summarize this section.**

A In this section I describe the overall economic status of Ameren's Labadie, Rush Island, and Sioux units from a resource planning perspective. I show that each of these units lost more than $20 million relative to the market over the past three years. I then discuss how the Rush Island and Labadie units are likely facing a total of more than $1 billion in environmental compliance costs if they continue to operate beyond 2024. I demonstrate that the only recent coal unit retirement assessments conducted by Ameren used a series of unreasonable assumptions and are out of date. I conclude that the Commission should not allow the recovery of capital costs incurred at the Rush Island, Labadie, or Sioux plants in 2018 or later until Ameren has presented sound analyses that justify those investments. I further recommend that the Commission require that Ameren present rigorous economic assessments of alternative near-term retirement dates for each of the Rush Island, Labadie, and Sioux units by the end of 2020.

***i. Each of the Labadie, Rush Island, and Sioux units lost more than $20 million relative to the market from 2016 through 2018.***

**Q Did you assess the recent economic performance of Ameren's coal units?**

A Yes. Using data provided by Ameren, I tabulated the aggregate net revenues of the Labadie, Rush Island, and Sioux units relative to the market for each year from 2016 through 2018. That is, I compared each unit's total costs to its total revenues in each of these years.

**Q What did you find regarding the overall economic performance of the Labadie, Rush Island, and Sioux units?**

A I find that each of the Labadie, Rush Island, and Sioux units incurred more than $20 million in aggregate net losses relative to the MISO market over the period from 2016 through 2018. Table 3 presents the results of my calculations. It shows that seven of the eight units incurred net losses relative to marginal market replacement in every year from 2016 through 2018 and that the eighth unit (Sioux Unit 2) incurred net losses in two of the three years. Together, I estimate that these eight units incurred cumulative net losses of $347 million relative to the market from 2016 through 2018.

**Table 3. Annual net revenues of Labadie, Rush Island, and Sioux units, 2016-2018 (2018 $Million)**

| Plant | Unit | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|
| Labadie | 1 | ($14) | ($4) | ($4) | ***($22)*** |
| Labadie | 2 | ($13) | ($4) | ($5) | ***($21)*** |
| Labadie | 3 | ($17) | ($6) | ($23) | ***($46)*** |
| Labadie | 4 | ($12) | ($4) | ($6) | ***($22)*** |
| Rush Island | 1 | ($36) | ($13) | ($19) | ***($67)*** |
| Rush Island | 2 | ($40) | ($12) | ($13) | ***($65)*** |
| Sioux | 1 | ($32) | ($20) | ($0) | ***($52)*** |
| Sioux | 2 | ($32) | ($23) | $3 | ***($51)*** |
| ***Total*** | ***All*** | ***($195)*** | ***($84)*** | ***($68)*** | ***($347)*** |

*Source: Ameren Response to Data Request Nos. SC 1.15 and SC 1.21; Synapse tabulation.*

**Q Describe how you arrived at the values in Table 3.**

A I calculated the annual net revenues presented in Table 3 using data provided by Ameren. These data include historical energy revenues, ancillary revenues, capacity revenues, fixed and variable O&M costs, fuel costs, and capital costs. I calculated annual net revenues by subtracting fixed and variable O&M costs, fuel costs, and capital costs from the summed energy, ancillary, and capacity revenues.

Ameren directly provided historical energy revenues, ancillary revenues, and capacity revenues at the unit level.[6] Ameren also provided hourly estimates of variable O&M costs in terms of dollars per megawatt-hour (MWh).[7] I multiplied these per-unit values by historical hourly generation data to arrive at historical variable O&M costs. Ameren provided fuel

[6] Ameren Responses to Data Request Nos. SC 1.15(m) and SC 1.21 (*see* Ex. AA-D-2).

[7] Attachments to Ameren Response to Data Request No. SC 1.21 (*see* Ex. AA-D-2).

costs, capital costs, and O&M costs at the plant level.[8] I used unit-level historical net generation data to scale plant-level fuel costs down to the unit level.[9] I used unit-level installed capacity data to allocate plant-level capital costs to individual units.[10]

To calculate unit-level fixed O&M costs, I first summed the calculated unit-level variable O&M costs to the plant level. Next, I subtracted the plant-level variable O&M costs from the plant-level total O&M costs to arrive at plant-level fixed O&M costs. Finally, I applied the ratio of each unit's installed capacity to the plant's total installed capacity to scale the plant-level fixed O&M costs down to the unit level.

**Q What are the implications of your findings regarding the recent economic performance of the Labadie, Rush Island, and Sioux units?**

**A** My findings indicate that these units are consistently incurring greater total costs than they are earning in total market revenues. While these losses relative to marginal market replacement do not mean that these units should all be retired immediately, they do highlight the need for careful evaluations of these units prior to Ameren making major life-extending capital investments. Ameren should conduct a rigorous economic retirement assessment for each of these units to evaluate if it is economical to continue operating the unit rather than replacing it with alternative resources.

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[8] Ameren Responses to Data Request Nos. SC 1.15(g), SC 1.15(i), and SC 1.15(k) (*see* Ex. AA-D-2).

[9] Attachments to Ameren Response to Data Request No. SC 1.21 (*see* Ex. AA-D-2).

[10] Ameren Response to Data Request No. SC 1.15(a) (*see* Ex. AA-D-2).

**Q Are resource planning issues and coal unit retirement dates relevant to this rate case proceeding?**

A Yes. In this case Ameren is proposing to recover hundreds of millions of dollars in 2018 coal unit capital expenses. These expenses are only justified to the extent that they are necessary to keep the coal units operating through prudent retirement dates. In addition, Ameren is proposing to recover hundreds of millions of dollars in annual coal unit O&M expenses. These annual expenses, which Ameren would continue to recover until its next rate case, are only justified as long as it is prudent for Ameren to keep its coal units online rather than retiring them.

***ii. Rush Island and Labadie face the likelihood of major environmental compliance costs if they continue to operate.***

**Q Have there been any major recent regulatory developments that affect the forward-going economics of Ameren's coal units?**

A Yes. In September 2019 the U.S. District Court for the Eastern District of Missouri issued a judgment requiring the installation of pollution controls at the Rush Island and Labadie plants to reduce emissions of sulfur dioxide ("$SO_2$").[11] Under this ruling, Rush Island Units 1 and 2 are required to comply with an $SO_2$ emissions limit of 0.05 pounds per million British thermal units (Btu) by March 2024.[12] The judgment further requires that Ameren propose a wet flue gas desulfurization ("FGD") system as the technology basis for controlling $SO_2$

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[11] Ex. AA-D-4, *United States v. Ameren Missouri*, Judgment, Doc. #: 1123, U.S. District Court Eastern District of Missouri, Case No. 4:11-cv-77-RWS (Sept. 30, 2019).

[12] *Id.* at 1.

emissions at Rush Island.[13] At Labadie, the judgment requires that Ameren install pollution control technology at least as effective as dry sorbent injection ("DSI") by September 2022.[14]

**Q What are the likely costs associated with these pollution control requirements?**

A The exact magnitude of the costs associated with installing and operating FGD at Rush Island and DSI at Labadie are uncertain. However, the total costs would likely exceed $1 billion. In discovery, Ameren indicated that it currently estimates that installing wet FGD at Rush Island would result in approximately $1 billion in capital costs and $30 million to $50 million in annual incremental O&M costs.[15] Ameren stated that it is still in the process of developing an estimate of the costs associated with installing DSI at Labadie.[16] However, the District Court's order cited an estimate that installing DSI at Labadie would require $55 million in capital expenditures and $53 million in annual operating costs.[17]

**Q What are the implications of these pollution control requirements for current and future investments at Rush Island and Labadie?**

A The magnitude of the compliance costs associated with operating Labadie beyond 2022 and Rush Island beyond 2024 adds greater urgency to the need to evaluate whether it is worth continuing to invest in these units rather than retiring them prior to the compliance deadlines. Given the marginal economic status of these units, accelerated retirement and replacement with lower-emitting resources could serve as a cost-effective compliance alternative to

[13] *Id*.

[14] *Id.* at 1-2.

[15] Ameren Response to Data Request No. SC 5.1 (*see* Ex. AA-D-2).

[16] *Id*.

[17] Ex. AA-D-5, *United States v. Ameren Missouri*, Memorandum Opinion and Order, Doc. #: 1122, U.S. District Court Eastern District of Missouri, Case No. 4:11-cv-77-RWS at 113 (Sept. 30, 2019).

investing approximately $1 billion in pollution controls. In general, prudent utility practice requires ramping down capital investments in generation units scheduled for retirement within the next three to five years. Thus, if Ameren were to decide to retire any of the Rush Island or Labadie units prior to the compliance deadlines, it should be ramping down capital investments in those units *today*.

**Q Has the Company evaluated the reasonableness of continuing to invest in Rush Island and Labadie in light of the recent court-ordered pollution control requirements?**

A No. Ameren argues that since the Company is appealing the District Court order, and since that order has temporarily been stayed pending an appeal, such an evaluation would be "premature."[18]

**Q Do you agree that it would be "premature" for Ameren to assess the reasonableness of planned investments in the Rush Island and Labadie plants?**

A No. The current compliance deadlines have implications for investments today, and possibly for past investments as well. Even if the compliance deadlines are delayed by a year or two, they would still affect near-term investment decisions. It is imprudent for Ameren to rely on the *possibility* of a District Court order being overturned on appeal to justify refusing to even *evaluate* the extent to which it should continue to invest in the Rush Island and Labadie units at this time in light of current economic expectations and risks.

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[18] Ameren Response to Data Request No. SC 2.50 (*see* Ex. AA-D-2).

**Q Has Ameren determined whether its 2018 Rush Island and Labadie capital expenditures would be necessary if the Company were to retire one or more of those units prior to 2023 or 2025?**

A Evidently not. In discovery, Ameren stated that the information regarding whether its 2018 coal plant capital expenditures would be necessary if its coal units were to retire prior to 2023 or 2025 "does not exist."[19] This suggests that some of Ameren's recent investments at its coal units may have been unnecessary in light of the current economic status and compliance requirements associated with those units.

**Q Should Ameren have assessed the potential impact of environmental compliance requirements on its Rush Island and Labadie units prior to investing hundreds of millions of dollars in those units in 2018?**

A Yes. While the court judgment requiring FGD at Rush Island and DSI at Labadie had not been issued at the time of Ameren's 2018 capital investments, in January 2017 the court issued a an order finding that Ameren's operation of Rush Island had violated the Clean Air Act.[20] This order set the stage for the remedy phase of the court proceeding that concluded in the order requiring FGD at Rush Island and DSI at Labadie.[21] Thus, by January 2017, Ameren knew, or should have known, that major near-term environmental compliance requirements at its coal units were likely on the horizon. Yet the Company spent nearly $200 million on 2018 capital investments at Rush Island and Labadie without assessing whether

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[19] Ameren Response to Data Request No. SC 1.6 (*see* Ex. AA-D-2).

[20] Ex. AA-D-6, *United States v. Ameren Missouri,* Memorandum Opinion and Order, Doc. # 852, U.S. District Court Eastern District of Missouri. No. 4:11-cv-77-RWS. (Jan. 23, 2017).

[21] Ex. AA-D-5 *United States v. Ameren Missouri*, Memorandum Opinion and Order, Doc. #: 1122, U.S. District Court Eastern District of Missouri, Case No. 4:11-cv-77-RWS at 3 (Sept. 30, 2019).

those investments were economically justified in light of market and regulatory considerations.

***iii. <u>Ameren's 2017 IRP is flawed and outdated and does not reasonably support continued investment in the Company's coal units.</u>***

**Q Has Ameren conducted any economic retirement assessments of its coal units within the past five years?**

A Yes. Ameren's 2017 IRP included two portfolios that evaluated 2024 retirement dates for the Labadie and Rush Island plants.[22] From these IRP analyses, Ameren concluded that accelerating the retirements of the Rush Island or Labadie plants would result in higher system costs.[23] Ameren therefore decided to maintain its existing retirement date assumptions for these plants.

**Q Did Ameren's 2017 IRP assess any alternative retirement dates for the Sioux units?**

A No.[24] This is a strange omission given that the 2017 IRP indicates that the Sioux units are higher-cost resources than the Rush Island and Labadie units.[25]

**Q Have you identified any flaws in Ameren's 2017 IRP coal unit retirement assessments?**

A Yes. Ameren's 2017 IRP retirement analyses relied on a series of assumptions that were unreasonable when Ameren submitted the IRP and are even less reasonable now. These

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[22] Ameren Response to Data Request No. SC 1.7 (*see* Ex. AA-D-2); Ex. AA-D-7, Ameren 2017 IRP, Ch. 9, at 3-4.

[23] Ex. AA-D-7, Ameren 2017 IRP, Ch. 9 at 23.

[24] *Id.* at 3.

[25] Ex. AA-D-8, Ameren 2017 IRP, Ch. 4 at 10.

flawed assumptions regarding environmental compliance costs, capacity prices, and renewable cost projections biased Ameren's analyses in favor of continued operation of the coal units. I discuss each of these assumptions in greater detail below.

**Q Did Ameren's 2017 IRP analyses account for the likelihood of $SO_2$ pollution control requirements at the Labadie or Rush Island plants?**

A No. The "environmental compliance" section of the Company's 2017 IRP does not even mention the possibility of FGD, DSI, or other major environmental compliance costs at these plants.[26]

**Q Was it reasonable for Ameren to ignore the possibility of $SO_2$ pollution control requirements at Rush Island and Labadie in its 2017 IRP analyses?**

A No. In 2016, a year prior to the publication of Ameren's 2017 IRP, there was a U.S. District Court trial regarding Ameren's liability for $SO_2$ emissions, and in January 2017 the court issued an order that found Ameren's emissions violated the Clean Air Act.[27] In light of these developments, Ameren's 2017 IRP should have at least accounted for the possibility of FGD, DSI, or other $SO_2$ emission control requirements. Instead, Ameren neglected to evaluate any sensitivities including such environmental compliance costs.

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[26] AA-D-9, Ameren 2017 IRP, Ch. 5, *available at:* https://www.ameren.com/-/media/missouri-site/files/environment/2017-irp/chapter-5-environmental-compliance.pdf?la=en-us-mo&hash=3FE6FDAA3F79EA5F78017D07CF495D34CAB5095D.

[27] Ex. AA-D-5, *United States v. Ameren Missouri*, Memorandum Opinion and Order, Doc. #: 1122, U.S. District Court Eastern District of Missouri, Case No. 4:11-cv-77-RWS at 3 (Sept. 30, 2019).

**Q Would it be reasonable for Ameren to ignore the likelihood of $SO_2$ pollution control requirements at Rush Island and Labadie if it were to conduct economic retirement assessments today?**

A No. Given the recent court order requiring installation of emission controls at Rush Island and Labadie, any reasonable current assessment of those units should incorporate the costs of FGD and DSI in a base scenario. Inclusion of these compliance costs would substantially reduce the net value of continuing to operate Rush Island and Labadie.

**Q Please describe the capacity price assumptions included in Ameren's 2017 coal unit assessments.**

A Under the 2017 IRP's base case assumptions, capacity prices were projected to increase from approximately $25 per megawatt-day (MW-day) in 2020 to about $220 per MW-day by 2025 and more than $300 per MW-day by 2030.[28]

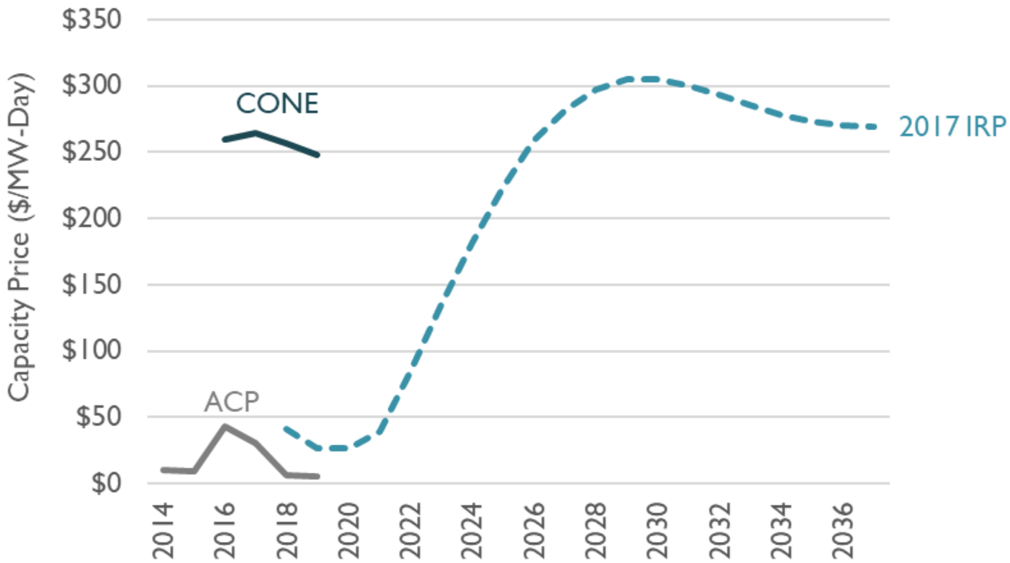
**Q How do these capacity price assumptions compare to recent MISO Planning Resource Auction (PRA) clearing prices?**

A Ameren's base 2017 IRP capacity price assumptions are considerably higher than historical MISO auction clearing prices ("ACP"), as shown in Figure 1. In fact, the highest historical ACP for MISO Zone 5–the zone that encompasses Ameren's service territory–was $72 per MW-day.[29] The Zone 5 ACP for the current MISO planning year was only $2.99 per MW-day.

[28] Ex. AA-D-10, Ameren 2017 IRP, Ch. 2 at 16. Ameren's IRP presents capacity prices in terms of dollars per kilowatt-year. For ease of comparison with other sources, I converted these values into units of dollars per MW-day by multiplying by 1000/365.

[29] Ex. AA-D-11, MISO 2013/2014 Planning Resource Auction Results; Ex. AA-D-12, MISO 2014/2015 Planning Resource Auction Results; Ex. AA-D-13, MISO 2015/2016 Planning

**Figure 1. Ameren's 2017 IRP capacity price assumptions and historical Zone 5 ACP and CONE results.**




*Sources: Ameren's 2017 IRP, MISO 2013/2014 through 2019/2020 PRA Results.*

*Notes: ACP and CONE values are calendarized versions of planning year values.*

**Q Are there additional reasons to believe that Ameren's 2017 IRP capacity price assumptions were unreasonably high?**

**A** Yes. In addition to being higher than historical MISO ACP results, Ameren's 2017 IRP capacity price projections are higher than historical Zone 5 cost of new entry ("CONE") values in every year from 2027 onward, as shown in Figure 1. A CONE value represents MISO's estimate of the annualized capital cost of constructing a new power plant.[30] A capacity price of CONE would only make sense in the unlikely case that a utility was paying for capacity from a newly built plant that provides zero energy or ancillary service value. It is

Resource Auction Results; Ex. AA-D-14, MISO 2016/2017 Planning Resource Auction Results; Ex. AA-D-15, MISO 2017/2018 Planning Resource Auction Results; Ex. AA-D-16, MISO 2018/2019 Planning Resource Auction Results; Ex. AA-D-17, MISO 2019/2020 Planning Resource Auction Results.

[30] Ex. AA-D-18, MISO, Cost of New Entry PY 2020/2021 at 4 (Sept. 11, 2019).

highly unlikely that Ameren would ever face a capacity price of CONE for a single year. It is even less likely that Ameren would face a capacity price at or near CONE for 10 years in a row. And it is extraordinarily unlikely that any entity would pay a price greater than CONE for market capacity. In fact, MISO uses its CONE estimate to set the maximum allowable PRA clearing price.[31] Thus, Ameren's 2017 IRP assumes that future capacity prices will not only be hundreds of times higher than recent ACP values but will also be higher than the highest possible capacity price allowed in any MISO PRA to date.

**Q What effect did Ameren's capacity price assumptions have on the projected value of its coal units?**

A Ameren's unreasonably high IRP capacity price projections in its 2017 IRP led the Company to overstate the likely future capacity value provided by its coal units. As an example, under an assumed capacity price of $280 per MW-day (beginning in 2027 under Ameren's 2017 IRP base case scenario), Rush Island would provide more than $100 million in annual capacity value annually and Labadie would provide more than $220 million in annual capacity value. In 2018, Rush Island actually earned less than $3 million in capacity revenues, while Labadie earned less than $6 million.[32]

**Q What solar cost assumptions did Ameren use in its 2017 IRP analyses?**

A Ameren's 2017 IRP assumed solar resource capital costs of $1,863 per kilowatt (kW).[33] This assumption was evidently largely based on a 2013 study.[34]

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[31] *Id.* at 4 (Sept. 11, 2019).

[32] Ameren Response to Data Request No. SC 1.15(m) (*see* Ex. AA-D-2).

[33] Ex. AA-D-19, Ameren 2017 IRP, Ch. 6 at 20.

[34] *Id.*

**Q Were Ameren's 2017 IRP solar cost assumptions reasonable at the time of the IRP filing?**

A No. Prior to the filing of Ameren's 2017 IRP, Lazard had released the 2016 version of its industry-standard levelized cost of energy ("LCOE") analysis. That analysis estimated solar capital costs of $1,300 to $1,450 per kW—more than $400 per kW lower than Ameren's assumption.[35]

**Q Are Ameren's 2017 IRP solar cost assumptions consistent with current industry expectations?**

A No. Lazard's 2019 LCOE analysis indicates that solar capital costs currently range between $900 and $1,100 per kW.[36] Ameren's own 2019 IRP Update includes a solar capital cost assumption that is significantly lower than the assumption used in its 2017 IRP. The 2019 IRP update indicates an assumed solar capital cost of $1,314 per kW, nearly 30 percent lower than Ameren's 2017 IRP assumption.[37] Figure 2 compares Ameren's 2017 and 2019 solar capital cost assumptions to Lazard's annual solar cost estimates.

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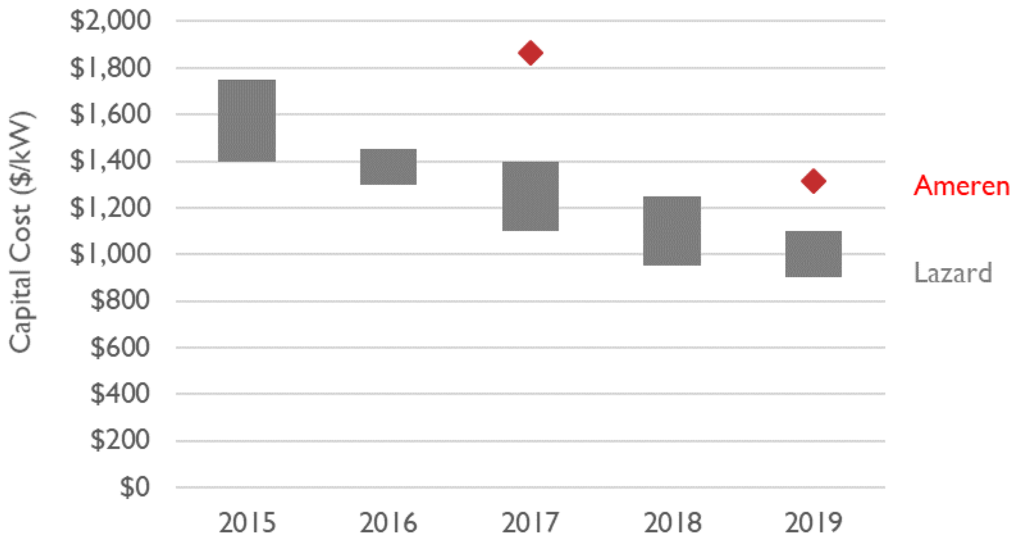
[35] Ex. AA-D-20, Lazard, Lazard's Levelized Cost of Energy Analysis – Version 10.0 at 11 (Dec. 2016), *available at:* https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

[36] Ex. AA-D-21, Lazard, Lazard's Levelized Cost of Energy Analysis – Version 13.0 at 11 (Nov. 2019), *available at:* https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

[37] Ex. AA-D-25, Ameren Missouri, IRP Update, Spring 2019 at 12, *available at:* https://www.ameren.com/-/media/missouri-site/files/environment/renewables/irp/irp-annual-update-report-public-2019.pdf?la=en-us-mo&hash=874A5FBD4CC96E18626BF00DA28EA68D019EA815.

**Figure 2. Utility-scale solar capital cost estimates, Lazard and Ameren.**




*Sources: Lazard's 2015-2019 LCOE Analyses (see Exs. AA-D-20 through AA-D-24), Ameren 2017 IRP, Ameren 2019 IRP Update.*

**Q Are Ameren's 2017 IRP solar cost assumptions consistent with responses to recent regional requests for proposals ("RFP")?**

**A** No. As part of its 2018 IRP process, Northern Indiana Public Service Company ("NIPSCO") issued an all-source RFP. NIPSCO's IRP indicates that the nine solar bids it received had an average capital cost of only $1,151 per kW.[38]

**Q What wind cost assumptions did Ameren use in its 2017 IRP analyses?**

**A** Ameren's 2017 IRP assumed Missouri wind capital costs of $1,859 per kW.[39]

[38] Ex. AA-D-26, NIPSCO, 2018 IRP at 56 (Oct. 31, 2018).

[39] Ex. AA-D-19, Ameren 2017 IRP, Ch. 6 at 22.

**Q Were Ameren's 2017 IRP wind capital cost assumptions reasonable at the time of the IRP filing?**

A No. Lazard's 2016 LCOE Analysis estimated wind capital costs of $1,250 to $1,700 per kW—more than $150 per kW lower than Ameren's assumption.[40]

**Q Are Ameren's 2017 IRP wind cost assumptions consistent with current industry expectations?**

No. Lazard's 2019 LCOE Analysis indicates current wind capital costs of between $1,100 and $1,500 per kW.[41] Ameren's own 2019 IRP Update includes a wind capital cost assumption of $1,594 per kW.[42] This represents a 14 percent reduction in cost relative to the 2017 IRP assumption. Figure 3 compares Ameren's 2017 and 2019 wind capital cost assumptions to Lazard's annual wind capital cost estimates.

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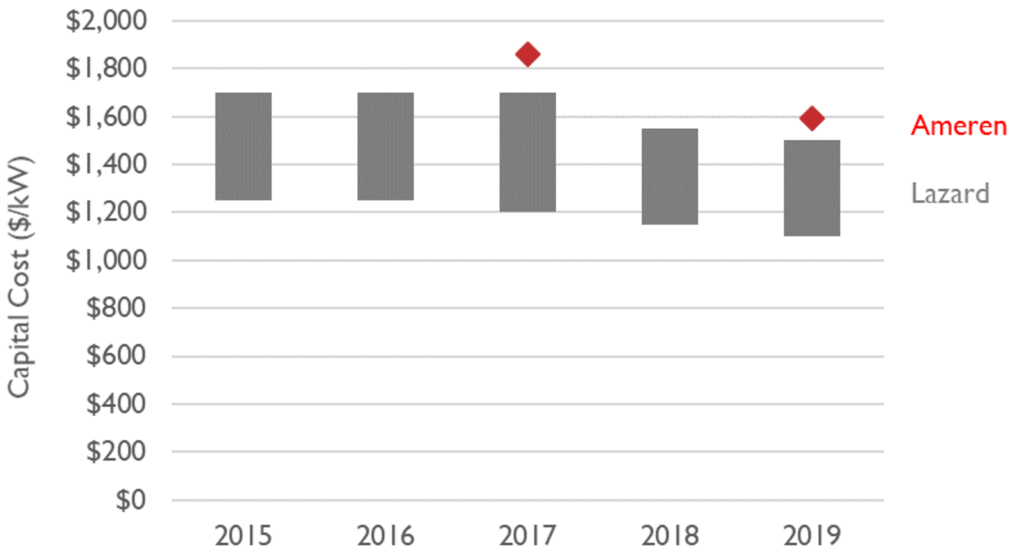
[40] Ex. AA-D-20, Lazard, Lazard's Levelized Cost of Energy Analysis – Version 10.0 at 11 (Dec. 2016).

[41] Ex. AA-D-21, Lazard, Lazard's Levelized Cost of Energy Analysis – Version 13.0 at 11 (Nov. 2019).

[42] Ex. AA-D-25, Ameren. Spring 2019. Integrated Resource Plan Update, at 12.

**Figure 3. Wind capital cost estimates, Ameren and Lazard**




*Sources: Lazard's 2015-2019 LCOE Analyses, Ameren 2017 IRP, and Ameren 2019 IRP Update.*

**Q Are Ameren's 2017 IRP wind cost assumptions consistent with responses to recent resource solicitations?**

**A** No. NIPSCO's 2018 IRP indicates that the eight wind bids it received had an average capital cost of $1,457 per kW.[43]

**Q What impact did Ameren's renewable cost assumptions have on the results of its coal unit assessments?**

**A** Ameren's 2017 IRP identified solar and wind as among its most economically attractive new resource options.[44] Thus, Ameren's unreasonably high renewable cost assumptions increased the cost of its least-cost replacement resource options and thereby increased the perceived

[43] Ex. AA-D-26, NIPSCO, 2018 IRP at 56 (Oct. 31, 2018).

[44] Ex. AA-D-7, Ameren 2017 IRP, Ch. 9 at 24; Ex. AA-D-19, Ameren 2017 IRP, Ch. 6 at 28.

cost of retiring coal units. The use of up-to-date renewable cost assumptions would likely result in lower coal unit replacement costs than those estimated in Ameren's 2017 IRP.

**Q What do you conclude regarding Ameren's 2017 IRP coal unit retirement assessments?**

A I conclude that Ameren's 2017 IRP analyses relied on assumptions that were unreasonably favorable to coal units at the time of the IRP and are even more out of date and unreasonable today. The 2017 IRP therefore cannot reasonably be relied upon for a determination of the prudence of Ameren's currently planned coal unit retirement dates. Instead, the Commission should require Ameren to conduct comprehensive unit retirement analyses that use reasonable, up-to-date assumptions for such key parameters as market energy and capacity prices, renewable costs, and environmental compliance costs.

**Q Based on your review of the overall economic status of the Labadie, Rush Island, and Sioux plants, what are your recommendations to the Commission?**

A I recommend that the Commission not allow the recovery of capital costs incurred at the Rush Island, Labadie, or Sioux plants in 2018 or later until Ameren has presented sound analyses that justify those investments in the face of major environmental compliance cost obligations and declining renewable resource costs. I also recommend that the Commission require Ameren to present rigorous economic assessments of alternative near-term retirement dates for each of the Rush Island, Labadie, and Sioux units by the end of 2020. Such analyses are necessary to establish whether it is reasonable for Ameren to continue investing in capital and fixed O&M expenditures at these units. These forward-looking assessments should be presented in a docketed proceeding to enable full Commission oversight and stakeholder review. They should incorporate up-to-date assumptions regarding market prices, resource costs, and environmental compliance costs.

## 5. <u>Ameren Coal Unit Commitment and Dispatch Practices</u>

**Q Please summarize this section.**

**A** In this section I review Ameren's coal unit commitment and dispatch practices. I show that Ameren self-commits its coal units in more than 99 percent of non-outage hours, such that the degree to which those units are online is not governed by market forces. I present four examples from 2018 in which I estimate that Ameren's self-commitment practices caused the Company to incur unnecessary net operational losses. I then discuss the flaws in Ameren's justifications for its coal unit commitment practices. Next, I present evidence indicating that Ameren has consistently offered its coal units into the MISO market at prices that are below their production costs. This increases the likelihood that those units will be dispatched uneconomically and incur net operational losses that are borne by ratepayers. I then discuss my concerns that Ameren's current FAC process does not allow for sufficient review of the Company's unit commitment and dispatch practices. I conclude by recommending that the Commission (1) disallow the recovery of operational costs incurred through the uneconomic commitment and dispatch of Ameren's coal units, (2) require Ameren to retain the analyses underlying its unit commitment decisions for a period of at least two years, and (3) revise Ameren's FAC process to enable more thorough and efficient review of the Company's unit commitment and dispatch practices.

### *i. <u>Ameren self-committed each of its Labadie, Rush Island, and Sioux units in more than 99 percent of non-outage hours in 2018.</u>*

**Q What is a unit commitment status?**

**A** A commitment status refers to the basis for determining whether a unit will operate at least up to its economic minimum in a given hour. Ameren specifies its unit's commitment status in regular submissions to MISO.

**Q What commitment status options are available to MISO market participants?**

A MISO's Business Practices Manual specifies the commitment status options available to market participants such as Ameren.[45] Commitment status options include:

1. **Economic.** The unit is available for economic commitment by MISO.
2. **Must-run (self-commit).** The unit operator commits the unit regardless of MISO's determination of an economic or reliability basis for having the unit online.
3. **Emergency.** The unit is available for commitment by MISO in emergency situations only.
4. **Outage.** The unit is unavailable for commitment due to an outage.
5. **Not Participating.** The unit is not participating in the day-ahead and/or real time markets but is otherwise available.

**Q How are Ameren's coal units typically committed?**

A Ameren generally utilizes a "must-run" commitment status for its Labadie, Rush Island, and Sioux units.[46] Figure 4 shows that Ameren self-committed each of these units in more than 60 percent of all hours in 2018.[47] Five of the eight units were designated as "must-run" in more than 90 percent of hours in 2018. Seven of the eight units did not have a commitment status of "economic" in a single hour in 2018.

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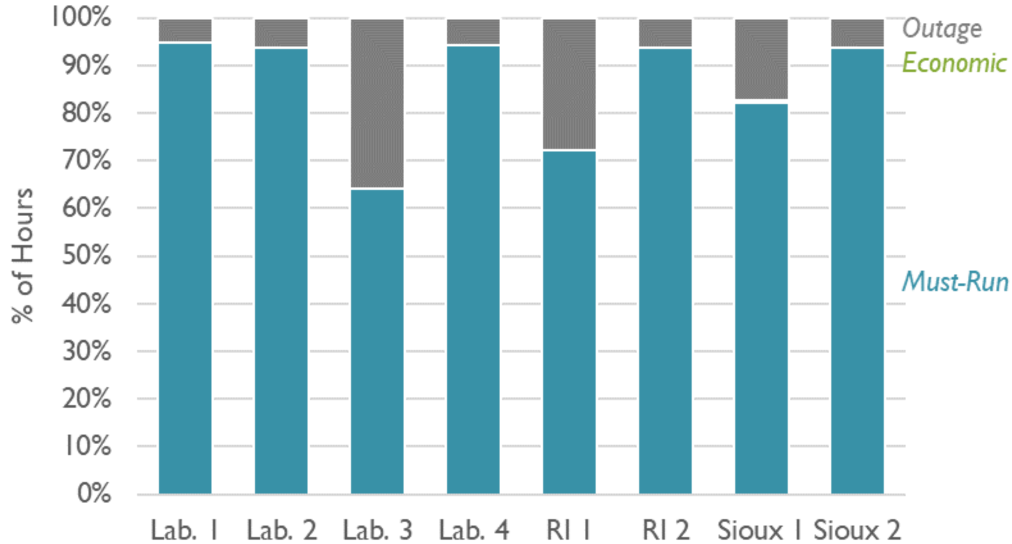
[45] Ex. AA-D-27, MISO, Business Practices Manual No. 002 – Energy and Operating Reserve Markets, Version 19 at Section 4.2.3.4.6 (Oct. 15, 2018).

[46] Ameren Response to Data Request No. SC 1.24a (*see* Ex. AA-D-2).

[47] Attachments "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 1.xlsx" and "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 2.xlsx" to Ameren Response to Data Request No. SC 3.19 (*see* Ex. AA-D-2).

**Figure 4. Ameren coal unit day-ahead commitment status, percentage of all 2018 hours**




*Source: Attachments to Ameren Response to Data Request No. SC 3.19 (see Ex. AA-D-2).*

When Ameren's coal units were not self-committed, it was almost always because those units were on outage. Figure 5 shows that each of the Labadie and Rush Island units was designated as "must-run" in every single hour in which it was not on outage in 2018. The only one of the eight units that ever had a day-ahead commitment status other than "must-run" or "outage" in 2018 was Sioux Unit 1, which had a commitment status of "economic" in less than 1 percent of hours.

**Figure 5. Ameren coal unit commitment status, percentage of non-outage 2018 hours.**


*Source: Attachments to Ameren Response to Data Request No. SC 3.19.*

**Q What implications do Ameren's coal unit commitment practices have for Commission oversight of Ameren's operational decision-making?**

**A** Ameren's practice of self-committing its coal units means that the extent to which those units operate is largely ungoverned by market forces. Ameren's decision to generally self-commit these units does not itself indicate whether or not Ameren's specific operational practices are prudent. However, this practice does mean that the Commission cannot rely on the MISO market to ensure that Ameren's units only operate when justified by economics or reliability requirements. Instead, Commission oversight is required to ensure prudent unit commitment and operational practices.

***ii. <u>Ameren's unit commitment practices led to unnecessary net operational losses in 2018.</u>***

**Q Have Ameren's coal unit commitment practices resulted in unnecessary costs?**

**A** Yes. My review of Ameren operational data indicates that the Company's persistent self-commitment practices led it to incur unnecessary net operational losses on behalf of ratepayers on at least four occasions in 2018. These occasions, which I describe in greater detail below, include:

1. Commitment and dispatch of Sioux Unit 1 in February 2018.
2. Commitment and dispatch of Sioux Unit 2 in February and March 2018.
3. Commitment and dispatch of Rush Island Unit 1 in February 2018.
4. Commitment and dispatch of Labadie Unit 2 in March 2018.

**Q Please describe your concerns with Ameren's commitment and dispatch of Sioux Unit 1 during February 2018.**

**A** On February 9, 2018, Sioux Unit 1 entered an outage.[48] The unit then remained offline until February 20, 2018, when it re-commenced generating energy around mid-day.[49] From that point until May 10, 2018, Ameren designated Sioux Unit 1 as a "must-run" unit in every hour.[50] My concern is that Ameren incurred unnecessary operational losses by returning Sioux Unit 1 to "must-run" service on February 20 rather than waiting for a period of higher energy prices to return the unit to service. I estimate that Sioux Unit 1 incurred more production costs than it earned in energy revenues in 73 percent of the hours in which it generated energy in February 2018 and in 69 percent of operating hours in March 2018. I further estimate that Sioux Unit 1 incurred about $155,000 in net operational losses during

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[48] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 2.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Sioux 1," columns C:D (*see* Ex. AA-D-2).

[49] Attachment "SIERRA_1-SC_001_21-Att-SC 1.21 - Sx 1.xlsx" to Ameren Response to Data Request No. SC 1.21, Column W (*see* Ex. AA-D-2).

[50] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 2.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Sioux 1," columns C:D (*see* Ex. AA-D-2).

the first 10 days following its return from outage and about $175,000 in net operational losses during the first 13 days following its return from outage. This suggests that Ameren could have saved about $175,000 in net operational costs by extending the Sioux Unit 1 outage from February 20 to March 5. Notably, extending the outage would not have resulted in any incremental start-up or cycling costs at Sioux Unit 1.

**Q Please describe your concerns with Ameren's commitment and dispatch of Sioux Unit 2 during February and March 2018.**

A Ameren self-committed Sioux Unit 2 as a "must-run" unit in every hour of February and March 2018.[51] However, throughout much of that period Sioux Unit 2 incurred more variable costs than it earned in operational revenues. I estimate that Sioux Unit 2 incurred more production costs than it earned in energy revenues in about 80 percent of the hours in which it generated energy in February 2018 and in about 70 percent of generating hours in March. Overall, I estimate that Sioux Unit 2 incurred about $298,000 in net operational losses for the full month of February. But this estimate understates the degree of avoidable losses because it includes the first week of the month, when the unit's performance was stronger, and excludes the first week of March, when the unit continued to lose money on an operational basis. I estimate that Sioux Unit 2 incurred about $385,000 in net operational losses during the period from February 9 through March 4. Accounting for the possibility that Sioux Unit 2 would have had to incur Ameren's estimated $11,000 in cold startup costs if it were to shut down on February 9 and re-start on March 5,[52] Ameren would still have avoided $374,000 in losses by taking the unit offline for that period.

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[51] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 2.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Sioux 1," columns C:D (*see* Ex. AA-D-2).

[52] Ameren Response to Data Request No. SC 1.23 (*see* Ex. AA-D-2).

**Q Please describe your concerns with Ameren's commitment and dispatch of Rush Island Unit 1 during February 2018.**

A On February 13, 2018, Rush Island Unit 1 entered an outage.[53] The unit then remained offline until February 16, 2018, when it re-commenced generating energy.[54] From that point until March 10, 2018, Ameren designated Rush Island Unit 1 as "must-run" in every hour.[55] During the period in February and March when the unit was online, I estimate that it incurred net operational losses of $67,000. In addition, by bringing Rush Island Unit 1 online during this uneconomic period only to have it go offline again in March, Ameren likely incurred unnecessary incremental startup costs of approximately $99,000.[56] Accounting for these incremental costs, I estimate that Ameren incurred approximately $167,000 in avoidable net losses by returning Rush Island Unit 1 to must-run service in February 2018.

**Q Please describe your concerns with Ameren's commitment and dispatch of Labadie Unit 2 in March 2018.**

A According to Ameren data, Labadie Unit 2 went on outage on March 17, 2018.[57] Ameren returned the unit to "must-run" operations on March 24 and subsequently designated Labadie

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[53] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 1.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Rush Island 1," columns C:D (*see* Ex. AA-D-2).

[54] Attachment "SIERRA_1-SC_001_21-Att-SC 1.21 - RI 1.xlsx" to Ameren Response to Data Request No. SC 1.21, Column W (*see* Ex. AA-D-2).

[55] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 1.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Rush Island 1," columns C:D (*see* Ex. AA-D-2).

[56] Ameren Response to Data Request No. SC 1.23 (*see* Ex. AA-D-2).

[57] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 1.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Labadie 2," columns C:D (*see* Ex. AA-D-2).

Unit 2 as "must-run" in every hour until June 2018.[58] My analysis indicates that Ameren incurred unnecessary net operational losses by returning Labadie Unit 2 to "must-run" service on March 24 rather than waiting for a period of higher energy prices to return the unit to service. I estimate that Ameren incurred $146,000 in unnecessary net operational losses by restarting Labadie Unit 2 on March 24 rather than waiting a week until April 1 to bring the unit back online. Extending the outage through April 1 would not have had any impact on start-up or cycling costs at Labadie Unit 2.

**Q Explain how you identified the above examples.**

A I identified these examples of uneconomic operation by reviewing operational data provided by Ameren. I first used this data to estimate the hourly net operational revenues earned by each coal unit in each hour of 2018. I then used this data to identify each occurrence of two types of events: (1) occasions when a unit incurred net operational losses over the course of a full calendar month and (2) instances when a unit incurred net operational losses during the 10 days following a return from an outage. For each identified event, I performed further analysis to determine the extent to which the event resulted in avoidable net losses.

**Q Why did you focus on these types of events?**

A I focused on these types of events because they are among the clearest markers of uneconomic commitment and dispatch practices. While it may make sense for a unit to incur uneconomic operational losses over the course of days or weeks in order to avoid cycling costs and remain online for high-value hours, a full month of net losses is unlikely to be justifiable. And there are even fewer possible justifications for a unit incurring persistent net losses in the days and weeks following an outage, since the unit could have easily avoided

[58] Attachment "SIERRA_3-SC_003_19-Att-SC 3.19 - Commit Status 2015 - 2019 - 1.xlsx" to Ameren Response to Data Request No. SC 3.19, tab "Labadie 2," columns C:D (*see* Ex. AA-D-2).

those losses by remaining offline for longer without incurring incremental startup or cycling costs.

**Q Explain how you calculated the losses associated with the above examples of uneconomic commitment practices.**

**A** I calculated the associated net losses using hourly and monthly operational data provided by Ameren. The Company directly provided hourly energy revenue and ancillary revenue data for each of its coal units for 2018.[59] Ameren also provided hourly net generation data and hourly estimates of variable O&M expense in terms of dollars per MWh. Ameren stated that it was unable to provide fuel costs at the unit or hourly scale but the Company provided average monthly fuel costs in terms of dollars per MWh for each of its coal plants.[60] I added the hourly variable O&M costs to the average fuel cost for the relevant plant and month to estimate hourly variable production costs in terms of dollars per MWh. I then multiplied these values by hourly net generation to arrive at hourly variable production costs in terms of dollars. I subtracted hourly variable costs from hourly energy and ancillary revenues to estimate hourly net operational revenues. Finally, I summed up hourly net operational revenues for the periods described above to arrive at estimates of net operational losses associated with the described events.

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[59] Attachments “SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 1.xlsx,” “SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 2.xlsx,” “SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 3.xlsx,” “SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 4.xlsx,” “SIERRA_1-SC_001_21-Att-SC 1.21 - RI 1.xlsx,” “SIERRA_1-SC_001_21-Att-SC 1.21 - RI 2.xlsx,” “SIERRA_1-SC_001_21-Att-SC 1.21 - Sx 1.xlsx,” and “SIERRA_1-SC_001_21-Att-SC 1.21 - Sx 2.xlsx” to Ameren Response to Data Request No. SC 1.21 (*see* Ex. AA-D-2).

[60] Ameren Response to Data Request No. SC 1.21f; Attachments to Ameren Response to Data Request No. MPSC 48 (*see* Ex. AA-D-2).

**Q What are the total losses associated with the instances of uneconomic decision-making you describe above?**

A I estimated that the above instances collectively resulted in net losses of about $861,000.

**Q Do the above examples constitute the only examples of uneconomic Ameren unit commitment practices in 2018?**

A Not necessarily. In focusing on cases where units incurred losses over a full month or incurred losses immediately following an outage, I have attempted to identify some of the clearest instances of uneconomic commitment practices. However, it is possible that the Ameren coal units incurred avoidable net operational losses on a smaller scale on other occasions in 2018.

**Q How did the 2018 energy market environment affect the impact of Ameren's coal unit self-commitment practices on the Company's operational revenues in that year?**

A In 2018, local electricity prices were generally higher than they had been in the previous two years. As a result, Ameren's general practice of self-committing its coal units did not result in as many instances of substantial net losses as in prior years. For example, Ameren data indicates that in 2016, when energy prices were lower, the Sioux and Rush Island plants each incurred more than $3 million in net operational losses over the course of the *entire year*. This suggests that the relatively smaller losses associated with uneconomic commitment practices in 2018 may reflect a fortunate increase in energy prices rather than sound underlying commitment and dispatch practices.

***iii. <u>Ameren has not provided sufficient justification for its coal unit commitment practices.</u>***

**Q What explanation has Ameren offered for its general practice of self-committing its Labadie, Rush Island, and Sioux coal units?**

A Ameren has stated that it self-commits these units because they have high restart costs and will face higher forced outage rates and increased maintenance and capital costs if they are cycled on and offline frequently.[61]

**Q Does this explanation justify the four examples of uneconomic unit commitment you describe above?**

A No. In three of those four instances the primary problematic decision was the choice to bring a unit back from an outage rather than extending the outage. In these cases, keeping the unit offline would not have resulted in any additional restarts or cycling costs. In the fourth case, the degree of losses was far higher than the cost of restarting the unit, as described above.

**Q Does Ameren conduct any analyses to inform its unit commitment decisions?**

A Ameren claims that it performs such analyses on a daily basis.[62] Ameren states that these analyses include comparisons of production costs to forecasted electricity prices for the next 10 days and account for potential startup and cycling costs. However, in discovery Ameren stated that it could not provide any of the analyses it conducted in the past three years because those analyses are overwritten each day.[63]

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[61] Ameren Response to Data Request No. SC 1.24a (*see* Ex. AA-D-2).

[62] Ameren Response to Data Request No. SC 1.24c (*see* Ex. AA-D-2).

[63] *Id.*

**Q In your opinion, is it reasonable for Ameren to over-write its unit commitment analyses each day?**

A No. It is critical for the Commission and interested stakeholders to be able to review the reasonableness of Ameren's unit commitment decisions in order to assess the prudence of operational costs. By deleting its prospective unit commitment analyses before they can be reviewed, Ameren unreasonably limits the amount of useful information available to assess the prudence of Ameren's commitment practices.

**Q Based on your review of Ameren's operational data and the Company's description of its prospective unit commitment analyses, do you have general concerns regarding the Company's process for deciding whether to self-commit its units?**

A Yes. I have two general concerns. First, it appears that Ameren maintains a default presumption that its units should remain online unless there is overwhelming evidence to the contrary. This is partly reflected in the Company's apparent stance that it will only take a unit offline if that unit is forecasted to incur net operational losses that are substantially larger than some assumed restart and cycling costs over the course of the next 10 days. Under this approach, a unit could incur steady losses every day of the year without sparking a decision to remove a "must-run" designation so long as those daily losses did not outweigh the assumed startup and cycling costs over a 10-day period. Second, Ameren does not appear to apply the same rigor to a decision to bring a unit back online as it does for de-committing a unit. Specifically, Ameren does not appear to require that its forecasts show that a unit will provide sufficient near-term net operational revenues to outweigh startup and cycling costs before the Company decides to bring a unit back from an outage. This is reflected in the examples described above in which units incurred net operational losses in the days and weeks following an outage. At a minimum, I would expect that a prudent utility should not use a "must-run" commitment status to bring a unit back from an outage except in extraordinary cases. Yet Ameren pursued this strategy repeatedly in 2018.

***iv. <u>Ameren consistently offers its coal units into the MISO market at prices below their production costs.</u>***

**Q What are Ameren's options for determining the extent to which its coal units operate above their economic minimum levels?**

**A** MISO's Business Practices Manual specifies five options available to market participants such as Ameren for determining the extent to which their coal units are dispatched above their economic minimum levels.[64] These dispatch status options are generally similar to the MISO unit commitment status options and include (1) Economic, (2) Self-Schedule, (3) Not Qualified, (4) Not Participating, and (5) Emergency.

**Q How are Ameren's coal units typically dispatched above their economic minimum levels?**

**A** Ameren rarely self-schedules the exact level of output from its coal units.[65] Instead, Ameren selects a dispatch status of "Economic" and submits generation offers to MISO. These generation offers consist of paired price and megawatt (MW) submissions. The offers often are made up of multiple segments, whereby Ameren offers to dispatch a certain amount of available capacity at a given price and offers to dispatch a larger amount of capacity at some higher price. MISO incorporates these offers into its calculation of the least-cost way to serve regional electricity requirements in each hour. Generally, if a unit has been committed and its offer price is lower than its local locational marginal price (LMP), that unit will be dispatched above its economic minimum level.

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[64] Ex. AA-D-27, MISO, Business Practices Manual No. 002 – Energy and Operating Reserve Markets, Version 19 at Section 4.2.3.4.6 (Oct. 15, 2018).

[65] Ameren Response to Data Request No. SC 1.24b (*see* Ex. AA-D-2).

**Q What is the basis for the offer prices that Ameren submits to MISO?**

A Ameren claims that its generation offers are based on its incremental production costs, including costs associated with fuel, transportation, variable O&M, emission controls, ash landfills, and emission allowances.[66]

**Q Do you have any concerns with Ameren's coal unit generation offer practices?**

A Yes. I am concerned that Ameren consistently offers its coal units into the MISO market at prices that are below their variable costs of production.

**Q How did you assess Ameren's generation offer practices?**

A I compared Ameren's 2018 hourly coal unit generation offer prices[67] to plant-level monthly average fuel costs and total production costs.[68] If Ameren's hourly coal unit offer prices reasonably reflect its incremental production costs, the offer prices should generally fall within the same range as the average variable production costs. Temporal variations may cause the offer prices to be somewhat higher or lower than monthly average production costs at different times. But it is mathematically impossible for the hourly incremental production costs that Ameren claims to be the basis for its offer prices to be lower (or higher) than monthly average variable production costs in every hour of a given month.

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[66] Ameren Response to Data Request No. SC 1.22a (*see* Ex. AA-D-2).

[67] Attachments "SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 1.xlsx," "SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 2.xlsx," "SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 3.xlsx," "SIERRA_1-SC_001_21-Att-SC 1.21 - LAB 4.xlsx," "SIERRA_1-SC_001_21-Att-SC 1.21 - RI 1.xlsx," "SIERRA_1-SC_001_21-Att-SC 1.21 - RI 2.xlsx," "SIERRA_1-SC_001_21-Att-SC 1.21 - Sx 1.xlsx," and "SIERRA_1-SC_001_21-Att-SC 1.21 - Sx 2.xlsx" to Ameren Response to Data Request No. SC 1.21 (*see* Ex. AA-D-2).

[68] Ameren Response to Data Request No. SC 1.21f; Attachments to Ameren Response to Data Request No. MPSC 48 (*see* Ex. AA-D-2).

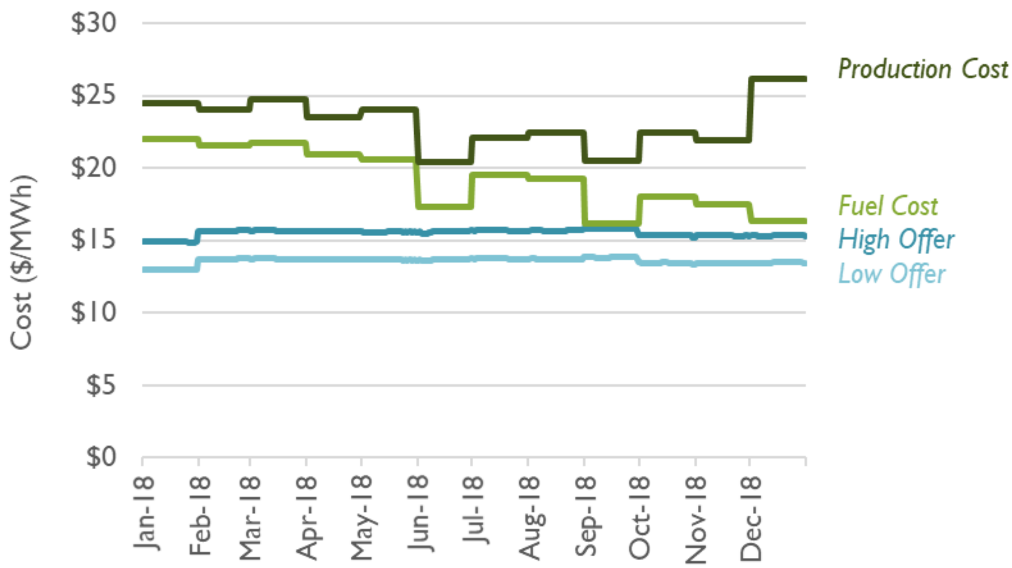
**Q What did your review of Ameren's coal unit generation offers indicate?**

A My review of Ameren's coal unit generation offers indicates that the Company tends to offer most of its coal units into the market at prices that are below their production costs. For some units, even the highest-priced offer segments were consistently lower than the units' fuel costs, which represent only a portion of total variable production costs.

**Q Does this offer price issue particularly affect a subset of Ameren's coal units?**

A Yes. I find that in 2018 this issue was particularly pervasive for the Labadie units. Figure 6 compares the lowest and highest offer prices submitted by Ameren for Labadie Unit 1 in each hour of 2018 to the average fuel costs and production costs incurred by Labadie Unit 1 in 2018. In every hour of 2018, the highest offer price was lower than the average fuel cost for that month. In January, average fuel costs at Labadie were more than $7 per MWh higher than the highest offer price Ameren submitted for Labadie Unit 1 in that month.

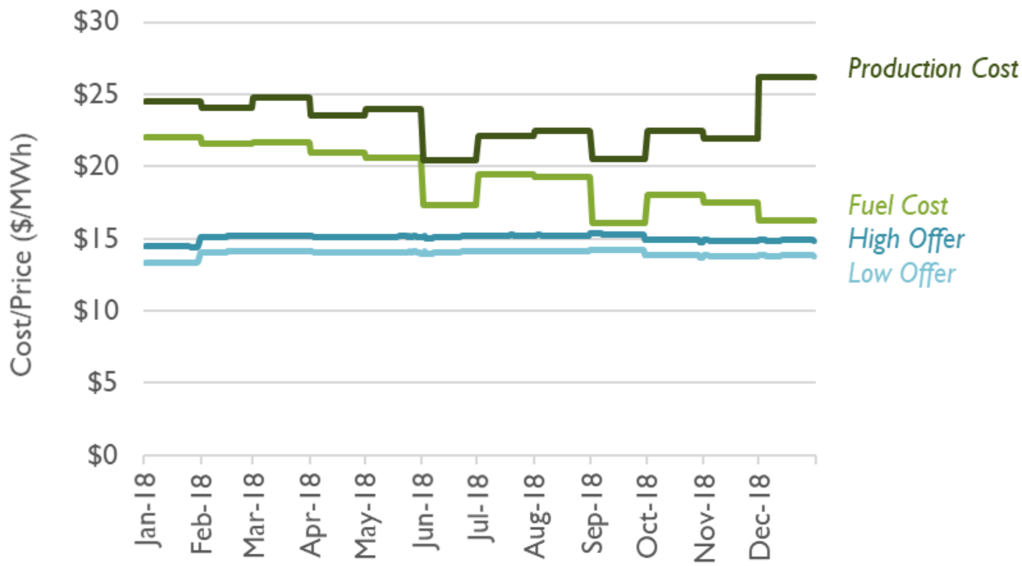
**Figure 6. Labadie Unit 1 2018 offer prices, fuel costs, and production costs.**




*Sources: Attachments to Ameren Response to Data Request No. SC 1.21; Attachments to Ameren Response to Data Request No. MPSC 48.*

Figure 7 presents a similar picture for Labadie Unit 2. Again, the highest offer price submitted by Ameren was lower than the average monthly fuel cost in every hour in 2018.

**Figure 7. Labadie Unit 2 2018 offer prices, fuel costs, and production costs.**




*Sources: Attachments to Ameren Response to Data Request No. SC 1.21; Attachments to Ameren Response to Data Request No. MPSC 48.*

**Q What problems arise from Ameren submitting offer prices that are lower than its variable production costs?**

**A** The problem with submitting offers that do not accurately reflect Ameren's variable production costs is that such offers could result in Ameren's generation units being dispatched above their economic minimum even when the incremental costs of that additional generation are greater than the energy value of that generation. In other words, low offer prices can result in uneconomic dispatch, which can lead to net operational losses that are ultimately passed on to Ameren ratepayers. These losses are on top of any losses resulting from uneconomic unit commitment decisions. In addition, generation offers that are below Ameren's variable production costs could unreasonably depress regional wholesale market prices and thus distort the market signals faced by alternative resources such as energy efficiency and renewables.

***v. Ameren's current FAC process does not allow for sufficient review of its commitment and dispatch decisions.***

**Q Besides rate cases such as this one, are there other types of Commission dockets in which Ameren's unit commitment and dispatch practices are a proper topic of investigation?**

A Yes. The reasonableness of Ameren's unit commitment and dispatch practices should also be subject to scrutiny in the Company's FAC adjustment proceedings. Unlike rate cases, FAC proceedings occur with sufficient frequency to enable regular review of Ameren's operational practices.

**Q Do you have any concerns with the current structure of Ameren's FAC proceedings?**

A Yes. I have two concerns. First, I believe that that Ameren's current FAC process does not allow sufficient time for proper review of Ameren's unit commitment and dispatch practices. Under current Commission policy, Commission Staff must submit a recommendation regarding Ameren's proposed adjustment within 30 days of the Company's FAC adjustment filing and the Commission must approve or reject the filing within 60 days.[69] This provides very limited time for substantive review and analysis of Ameren's operational decisions. Second, I am concerned that the frequency of Ameren's FAC adjustment filings may not allow for the most efficient allocation of time and resources toward evaluating Ameren's commitment and dispatch practices. Under the current FAC process, Ameren submits FAC adjustment filings every four months, which results in the FAC rate faced by Ameren customers changing three times per year.[70] While periodic rate cases are unlikely to enable

[69] Ex. AA-D-28, Missouri Public Service Commission File No. ER-2020-0143, Order Directing Notice, Setting Intervention Deadline and Directing Staff Recommendation (Nov. 25, 2019); Missouri Public Service Commission Rule 20 CSR 4240-20.090(4).

[70] Direct Testimony of Marci L. Althoff on Behalf of Ameren at 2-3.

sufficiently frequent review of unit commitment and dispatch practices, review every four months is likely unnecessary. Instead, I believe that an annual review process strikes an appropriate balance between sufficient oversight and efficient use of resources.

**Q Do you have any recommendations regarding Ameren's FAC process?**

A Yes. My primary recommendation is that the Commission amend its rules to provide Staff and other stakeholders with at least three months following an Ameren FAC adjustment filing to submit their findings and recommendations regarding the proposed adjustment. This would allow sufficient time to incorporate analysis of commitment and dispatch practices into any recommended adjustments. If the Commission finds it unnecessary or impractical to amend its rules in this way, it should at least set minimum FAC filing requirements that enable Staff and stakeholders to review unit commitment and dispatch practices. These minimum filing requirements should include, for each thermal generation unit, hourly net generation, hourly energy offer quantities and prices, hourly energy revenues, hourly LMPs, hourly commitment status, hourly economic minimum level, hourly dispatch status, hourly variable O&M costs, monthly fuel costs, monthly production costs, and all daily analyses used to inform commitment practices and generation offers. In addition, I recommend that the Commission structure the FAC process to enable annual, rather than triannual, review of unit commitment and dispatch practices. This could be done by changing filing requirements such that FAC filings occur once a year rather than three times a year. Alternatively, the Commission could maintain the current practice of triannual filings but could structure one of the three annual FAC processes to allow sufficient time and scope to address possible FAC adjustments based on unit commitment and dispatch practices over the previous full year.

**Q What are your overall recommendations with respect to Ameren's unit commitment and dispatch practices?**

A I recommend that the Commission disallow the recovery of operational costs incurred through the uneconomic commitment and dispatch of Ameren's coal units. I estimate the 2018 value of these unnecessary net operational losses, which should be deducted from

Ameren's revenue requirement, to be $861,000. I also recommend that the Commission require Ameren to retain the analyses underlying its unit commitment decisions for a period of at least two years. These analyses should clearly specify the costs and revenues that are accounted for within the analyses. Finally, I recommend that the Commission revise Ameren's FAC process to allow for substantive annual review of Ameren's unit commitment and dispatch practices.

**Q Does this conclude your revenue requirement direct testimony?**

**A** Yes, it does.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 001.24

Regarding Ameren Missouri's unit commitment decision process for its coal units:

a. Describe Ameren Missouri's process for determining whether to commit its coal units outside of the MISO or SPP day-ahead energy markets and operate them up to at least their minimum operation levels.

b. Describe Ameren Missouri's process for determining whether to self-schedule its coal units at generating levels above their minimum operation levels.

c. Does Ameren Missouri perform economic analyses to inform its unit commitment decisions (i.e., decisions regarding whether to designate its coal units as must run or take them offline for economic reasons)?

i. If not, explain why not.

ii. If so, provide all such analyses conducted since 2015 in native, machine-readable format.

**RESPONSE**

| Prepared By: Mark Peters |
|---|
| Title: Manager Load Forecasting & Market Analysis |
| Date: 10/28/2019 |

1. Ameren Missouri's coal fired units are all registered in the MISO market. They are not committed outside of MISO.

   To the extent that this data request is in regards to Ameren Missouri's use of a must run unit commitment status for its coal fired units, 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 (again, if not placed in must run commit status), warrant such a designation. These units include all of Ameren Missouri's coal-fired units other than those at the Meramec Energy Center. Must run commit status may also be used for units at the Meramec Energy Center when such a unit is scheduled for testing to ensure that the unit will be in operation for the test, or in instances where the margin on the first day alone would not warrant committing the unit (due to its start-up cost) but where the expected margin over a longer period of time justifies committing the unit.

In making its commit status decisions, the Company's guiding principle is to clear (i.e., sell energy from) its units in the market when doing so benefits customers. Given that the current MISO algorithm for unit commitment only analyzes the 24-hour period of the next calendar day, Ameren Missouri looks past the next 24 hours to make this assessment. This process takes into consideration the costs associated with decommitting a unit, including; 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. Consideration is also given to unit downtime minimums. That is, if a unit downtime minimum is for more than one day, de-committing the unit based only on the next day's MISO model results could mean that the unit will forego margins for the following days when it remains shut-down.

2. Ameren Missouri does not utilize a self-schedule dispatch status for its coal fired units as a matter of course.

3. Ameren Missouri utilizes a combination of quantitative and qualitative analysis to inform its unit commitment decisions.

   Each day it performs two separate economic analyses.

   First, Ameren Missouri makes an assessment of "generation in the money", by unit, by hour, for each of the next 10 days, utilizing the PCI tool to perform a simulated unit dispatch of each unit based on its incremental production cost, unit characteristics and a forecast of LMPs. The model provides an indication of the level of generation that is "in the money" for a given hour (that is to say that the LMP is in excess of the incremental production cost). Hours for which the unit is not "in the money" do not have values in them.

   Additionally, a projection of each unit's energy margin for the next 10 days is separately calculated. This is accomplished by first estimating that amount of energy which could be expected to clear in the MISO energy market, for each hour, based upon each units then current as offered production cost and a forecasted estimated of LMPs. The difference between these LMPs and as offered production costs are then applied to the projected level of unit output to provide an estimate of each unit's energy margin, by hour. This process is repeated by adjusting LMPs up and down by 5%.

For units for whom such indicated margins may be negative, consideration is given to the factors listed in part a above.

Analysis results that informed the commitment decision cannot be provided because the PCI tool overwrites data each day that it is utilized.

# Ameren Missouri Fuel Adjustment Clause

| Billing Mon Effective | Accumulation Period | Total Energy Cost | Base Energy Cost | Diff | 95% | 5% |
|---|---|---|---|---|---|---|
| 10/1/2009 | 1 | $43,875,102 | $57,146,229 | ($13,271,127) | ($12,607,571) | ($663,556) |
| 2/1/2010 | 2 | $152,992,169 | $133,185,194 | $19,806,975 | $18,816,626 | $990,349 |
| 6/1/2010 | 3 | $137,483,785 | $89,976,721 | $47,507,064 | $45,131,711 | $2,375,353 |
| 10/1/2010 | 4 | $159,987,597 | $85,013,117 | $74,974,480 | $71,225,756 | $3,748,724 |
| 2/1/2011 | 5 | $249,802,845 | $183,733,223 | $66,069,622 | $62,766,141 | $3,303,481 |
| 6/1/2011 | 6 | $163,832,252 | $138,583,131 | $25,249,121 | $23,986,665 | $1,262,456 |
| 10/1/2011 | 7 | $131,274,998 | $125,408,921 | $5,866,077 | $5,572,773 | $293,304 |
| 2/1/2012 | 8 | $220,372,707 | $189,416,096 | $30,956,611 | $29,408,780 | $1,547,831 |
| 6/1/2012 | 9 | $184,529,834 | $149,157,813 | $35,372,021 | $33,603,420 | $1,768,601 |
| 10/1/2012 | 10 | $173,100,120 | $142,363,618 | $30,736,502 | $29,199,677 | $1,536,825 |
| 2/1/2013 | 11 | $277,767,604 | $191,274,586 | $86,493,018 | $82,168,367 | $4,324,651 |
| 6/1/2013 | 12 | $215,139,881 | $159,767,211 | $55,372,670 | $52,604,037 | $2,768,634 |
| 10/1/2013 | 13 | $216,210,765 | $175,851,067 | $40,359,698 | $38,341,713 | $2,017,985 |
| 2/1/2014 | 14 | $258,851,360 | $205,416,214 | $53,435,146 | $50,763,389 | $2,671,757 |
| 6/1/2014 | 15 | $253,492,306 | $193,506,450 | $59,985,856 | $56,986,563 | $2,999,293 |
| 10/1/2014 | 16 | $240,817,322 | $178,896,751 | $61,920,571 | $58,824,542 | $3,096,029 |
| 2/1/2015 | 17 | $249,019,250 | $201,847,377 | $47,171,873 | $44,813,279 | $2,358,594 |
| 6/1/2015 | 18 | $247,303,277 | $185,185,349 | $62,117,928 | $59,012,032 | $3,105,896 |
| 10/1/2015 | 19 | $219,712,423 | $172,604,076 | $47,108,347 | $44,752,930 | $2,355,417 |
| 2/1/2016 | 20 | $245,334,929 | $245,594,658 | ($259,729) | ($246,743) | ($12,986) |
| 6/1/2016 | 21 | $198,934,394 | $208,577,055 | ($9,642,661) | ($9,160,528) | ($482,133) |
| 10/1/2016 | 22 | $201,251,119 | $188,374,689 | $12,876,430 | $12,232,609 | $643,822 |
| 2/1/2017 | 23 | $263,286,202 | $251,811,350 | $11,474,852 | $10,901,109 | $573,743 |
| 6/1/2017 | 24 | $210,620,197 | $209,251,548 | $1,368,649 | $1,300,217 | $68,432 |
| 10/1/2017 | 25 | $162,512,377 | $169,959,612 | ($7,447,235) | ($7,074,873) | ($372,362) |
| 2/1/2018 | 26 | $206,020,072 | $193,742,567 | $12,277,505 | $11,663,630 | $613,875 |
| 6/1/2018 | 27 | $212,987,403 | $173,753,856 | $39,233,547 | $37,271,870 | $1,961,677 |
| 10/1/2018 | 28 | $169,414,142 | $164,348,099 | $5,066,043 | $4,812,741 | $253,302 |
| 2/1/2019 | 29 | $192,602,706 | $201,446,558 | ($8,843,852) | ($8,401,659) | ($442,193) |
| 6/1/2019 | 30 | $145,529,140 | $175,752,698 | ($30,223,558) | ($28,712,380) | ($1,511,178) |
| 10/1/2019 | 31 | $157,981,691 | $158,652,746 | ($671,055) | ($637,502) | ($33,553) |
| 2/1/2020 | 32 | $176,031,218 | $191,942,242 | ($15,911,024) | ($15,115,473) | ($795,551) |
| | | | | Credit | ($76,383,956) | ($4,020,208) |
| | | | | Charged/Absorbed | $880,587,803 | $46,346,726 |
| | Total | $6,338,071,187 | $5,491,540,822 | $846,530,365 | $804,203,847 | $42,326,518 |

| | | | |
|---|---|---|---|
| Total Customers paid | $6,295,744,669 | Total Ameren Missouri Paid | $42,326,518 |
| % Customers paid | 99.33% | % Ameren Missouri Absorbed | 0.67% |

All amounts are from Commission approved tariff sheets