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Witness: Andrew M. Meyer  
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**MISSOURI PUBLIC SERVICE COMMISSION**

**FILE NO. ER-2026-0291**

**DIRECT TESTIMONY**

**OF**

**ANDREW M. MEYER**

**ON**

**BEHALF OF**

**UNION ELECTRIC COMPANY**

**D/B/A AMEREN MISSOURI**

**St. Louis, Missouri  
June 2026**

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**DIRECT TESTIMONY**

**OF**

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**I. INTRODUCTION**

1

**Q. Please state your name and business address.**

2

3 A. My name is Andrew Meyer, and my business address is One Ameren Plaza,  
4 1901 Chouteau Avenue, St. Louis, Missouri 63103.

3

4

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

5

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

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7

**Q. What are your responsibilities as Senior Director, Energy Management  
& Trading?**

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10 A. I am responsible for Ameren Missouri's generation and load asset  
11 management in the wholesale energy markets. This includes real-time operation of the  
12 generation fleet within the applicable Regional Transmission Organization ("RTO");  
13 procurement of nuclear fuel, fossil fuels, and emission control commodities; financial and  
14 physical hedging of any energy, capacity, congestion-rights, or related exposures; and RTO  
15 stakeholder relations. I am also responsible for gas supply procurement for the Local  
16 Distribution Company (LDC), generation performance monitoring, NERC<sup>1</sup> compliance  
17 oversight, and operational responsibility for the renewable generation fleet and combustion  
18 turbine generator fleet.

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<sup>1</sup> North American Electric Reliability Corporation.

1           **Q.    Please describe your educational background and employment**  
2 **experience.**

3           A.    I earned Bachelor of Science degrees in Business Administration with a  
4 Management Emphasis, and Agricultural Economics from the University of Missouri –  
5 Columbia. I was employed by Continental Grain Company prior to joining Ameren. In  
6 1999, I joined Ameren's independent marketing affiliate, Ameren Energy Inc. Ameren  
7 Missouri assumed this corporate function in 2004. I have worked in several different  
8 capacities on the trading floor and in RTO stakeholder relations. My experience also  
9 includes a steady progression of leadership responsibilities for related activities involving  
10 commodity trading and procurement, as well as wholesale market operations.

11           **Q.    What is the purpose of your Direct Testimony?**

12           A.    To address the following issues relevant to this proceeding:

- 13           • Continuation of Ameren Missouri's Fuel Adjustment Clause ("FAC"),  
14 including compliance with the minimum filing requirements prescribed by  
15 the Commission's FAC rules.
- 16           • To demonstrate the ongoing volatility and uncertainty associated with  
17 Actual Net Energy Cost ("ANEC")<sup>2</sup> as well as the market drivers that  
18 influence the costs and revenues tracked in the FAC. These drivers include  
19 commodity prices and volumetric fluctuations in the Company's  
20 commodity and transportation requirements.
- 21           • To provide several components of net base energy costs ("NBEC") using  
22 trued-up test year values, including the appropriate level of off-system

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<sup>2</sup> Capitalized terms not otherwise defined in my testimony have the meanings given them in Rider FAC.

1 sales revenues ("OSSR"), net of the normalized capacity component of  
2 purchased power expense, which was used by Company witness Stephen  
3 J. Hipkiss in determining Ameren Missouri's NBEC utilized in the  
4 Company's FAC.

- 5 • To address Rider FAC Updates and Key Components, including updating  
6 the net base energy costs that form the base against which changes in the  
7 ANEC are tracked in the FAC.

8 **II. 20 CSR 4240-20.090(2)(A) REQUIREMENTS**

9 **Q. Is the Company requesting to continue its FAC?**

10 A. Yes. The essential elements that supported the Commission's approval of  
11 the FAC initially, and the Commission's continuation of it since it was first approved in  
12 2009, support its continuation now.

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

13 A. Continuation of an FAC is governed by Section 386.266, RSMo, and  
14 Commission Rule 20 CSR 4240-20.090, specifically Rule 20 CSR 4240-20.090(2)(A),  
15 which details the minimum filing requirements for continuation of an FAC. These  
16 minimum filing requirements are provided in the attached Schedule AMM-D1.

17 **Q. Please explain the basic structure of the Company's FAC?**

18 A. The FAC rate (defined as the "Fuel Adjustment Rate" or "FAR" in the  
19 tariff), is adjusted three times per year based upon changes in ANEC during each historical  
20 four-month accumulation period, as compared to Factor B, which is derived from the  
21 NBEC established in the most recently completed rate review. Once the rate adjustment is  
22 filed, 95% of the difference between ANEC and NBEC for the subject accumulation period

1 is recovered from (or returned to) customers over an eight-month recovery period. Interest  
2 is applied to the sums recovered or returned. Since the FAC's inception through June of  
3 this year, 51 such FAR filings have been made.

4 This core structure and operation of the FAC have not changed since it was first  
5 approved.

**Q. For what specific reasons does the Company recommend continuation  
of the FAC?**

6 A. Ameren Missouri's FAC should be continued because the nature of the  
7 costs and revenues reflected in the FAC make them appropriate for continued inclusion in  
8 this Rider, and to minimize the negative impact on the Company in recovering these costs  
9 and revenues absent an FAC. More specifically, the FAC should be continued for many  
10 reasons, including that: 1) all of the factors the Commission has historically considered in  
11 evaluating FACs favor continuation of the FAC; 2) the FAC is reasonably designed to  
12 provide the Company a sufficient opportunity to earn a fair return; 3) without an FAC,  
13 significant regulatory lag would be present and would prevent the Company from timely  
14 reflecting what can be and often are very significant changes in net energy costs in rates,  
15 whether those changes are up or down, and those changes can impact the Company's ability  
16 to earn a fair return; 4) elimination or any significant modification of the FAC would reflect  
17 an inconsistent regulatory policy that would harm the Company's access to needed capital  
18 at the lowest reasonable cost; and 5) Ameren Missouri's FAC is important to maintaining  
19 the Company's credit quality, primarily because virtually all other vertically integrated  
20 electric utilities with whom the credit rating agencies compare Ameren Missouri operate  
21 with FACs.

1           When the question of whether the FAC should remain in effect has been litigated,  
2 the Commission has consistently recognized that all of these reasons continued to  
3 demonstrate the appropriateness of the Company's FAC.<sup>3</sup> The Company's FAC was also  
4 continued in the last five general rate case proceedings by agreement of the settling parties,  
5 and each of those agreements was approved by the Commission.

6           **Q.     Please elaborate on why the nature of these costs and revenues meet the**  
7 **criteria for continuation of the Company's FAC.**

8           A.     The Commission considered three primary attributes of costs and revenues  
9 when approving Ameren Missouri's FAC initially and has in general continued to look at  
10 those attributes in subsequent requests. These attributes apply in-whole to the identified  
11 costs and revenues and warrant the continuation of a FAC. Specifically, these factors  
12 suggest that the nature of costs or revenues that would be included in the FAC should be:

- 13           1. Substantial enough to have a material impact upon revenue requirements  
14           and the financial performance of the business between rate cases;
- 15           2. Beyond the control of management, where the utility has little influence  
16           over experienced revenue or cost levels; and
- 17           3. Volatile in amount, causing significant swings in income and cash flows  
18           if not tracked.

19           **Q.     Are the Company's fuel and purchased power costs substantial?**

20           A.     Yes. The Company's fuel and purchased power costs, including  
21 transportation (reflected in Factors FC and PP in the current FAC tariff), are one of the  
22 Company's largest operations and maintenance ("O&M") expenses, representing  
23 approximately 58% of its total O&M costs in 2025. In addition, the Company's ANEC (the  
24 sum of Factors FC, PP, E, and R less OSSR in the FAC tariff) have fluctuated substantially  
25 since the FAC was first established, from a low of approximately \$280 million in 2009 to

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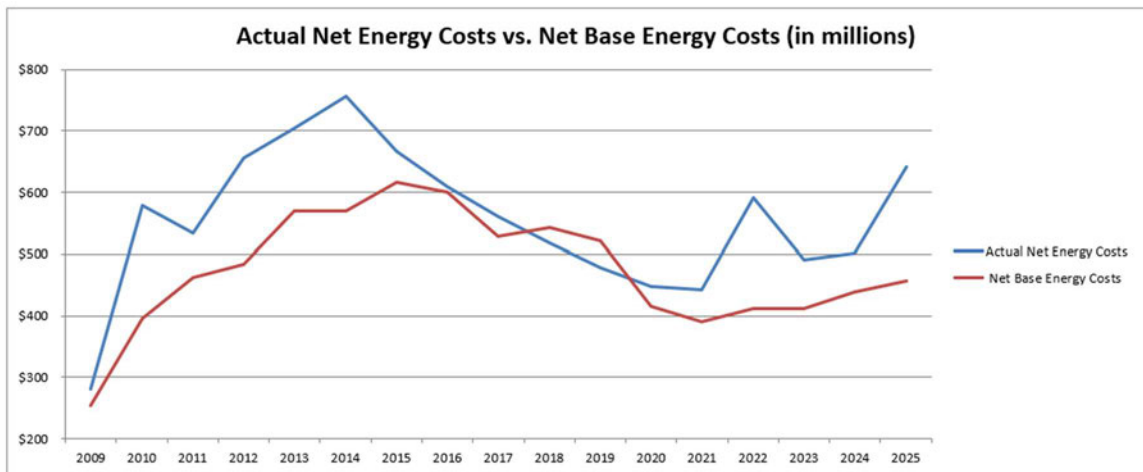
<sup>3</sup> File No. ER-2014-0258, *Report and Order*, pp. 102-104, issued on April 29, 2015.

1 a high of approximately \$756 million in 2014. While ANEC has trended lower since this  
2 time, volatile commodity market price swings in 2022 did cause a spike up to \$591 million  
3 in 2022, only to fall by approximately \$100 million in 2023, but spiked again to \$642  
4 million in 2025. Absent the FAC, those changes would have had an extremely material  
5 and detrimental impact on Ameren Missouri's financial performance between rate cases,  
6 and when decreases have occurred, those decreases would not have passed through to  
7 customers.<sup>4</sup> The changes in ANEC through the end of 2025 are depicted in Figure 1 below:

8

9

**Figure 1**



10 **Q. Are these costs and revenues beyond the control of management?**

11 A. The Company has no significant influence over these costs and revenues.

12 This has remained unchanged since the Company's FAC became effective in 2009 and has

13 not changed with respect to the question of control over the past 17 years during which the

14 Commission has approved continuation of the FAC many times. As in prior rate reviews,

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<sup>4</sup> Customers receive 95% of the benefit between rate reviews, since the FAC includes a 95% / 5% sharing mechanism.

1 the Company continues to lack control over the national and international fuel and power  
2 markets that dictate what its ANEC will be.<sup>5</sup>

3 **Q. Are volatility and uncertainty evident, and will volatility and**  
4 **uncertainty continue to exist?**

5 A. Yes. The volatility and uncertainty are evident in the Company's ANEC  
6 history. The Company's ANEC history shows substantial changes (up and down) over the  
7 past several years. The forward value of ANEC will be greatly impacted by changes to the  
8 Company's generation fleet and the generation fleet of the entirety of Midcontinent  
9 Independent System Operator, Inc ("MISO"). The MISO market, and in particular the  
10 ability of MISO to manage extreme weather events, can result in dramatic shifts in  
11 commodity market pricing. As demonstrated by abrupt increases in Figure 1 for 2022 and  
12 2025, the prices for fuel and energy have a large impact on ANEC.

13 As shown in Figure 1, ANEC has increased well over \$100 million from a given  
14 year to the next and has also seen large year-to-year decreases. These significant up and  
15 down year-over-year comparisons demonstrate the volatility and uncertainty of the  
16 Company's fuel and purchased power costs net of off-system sales, including  
17 transportation. The national and international markets that set the prices for fuel and power  
18 continue to be volatile. The volatility we see in the FAC could result in higher charges to

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<sup>5</sup> The Commission has recognized this for years: File No. ER-2008-0318, *Report and Order*, p. 63, issued January 27, 2009, ("[M]ost of the costs that comprise [Ameren Missouri's] fuel costs, the costs that would be tracked in a fuel adjustment clause, are dictated by national and international markets, including competing purchases by China and India, far beyond the control of [Ameren Missouri]."); File No. ER-2014-0258, *Report and Order*, p. 103, issued April 29, 2015 ("Those fuel and purchased power costs continue to be dictated by national and international markets and thus are outside the control of Ameren Missouri's management."); File No. ER-2019-0335, *Amended Report and Order*, pp. 9-10, issued July 15, 2020 ("Fuel costs are volatile and electric utilities do not have complete control over those fuel costs. In general, Ameren Missouri's net energy costs are set by markets for energy and fuel that are largely beyond Ameren Missouri's control" [footnotes omitted]).

1 customers, but it could result in a reduction of the FAC rates and lower charges to  
2 customers as well, as we have seen on several occasions, depending on volumes of fuel  
3 burned, prices for power, etc. As the Commission knows, 95% of any such reduction, as  
4 compared to the NBEC established in this case, will be passed through to customers.

5 **Q. Do the Company's hedging programs for ANEC components eliminate**  
6 **volatility and uncertainty?**

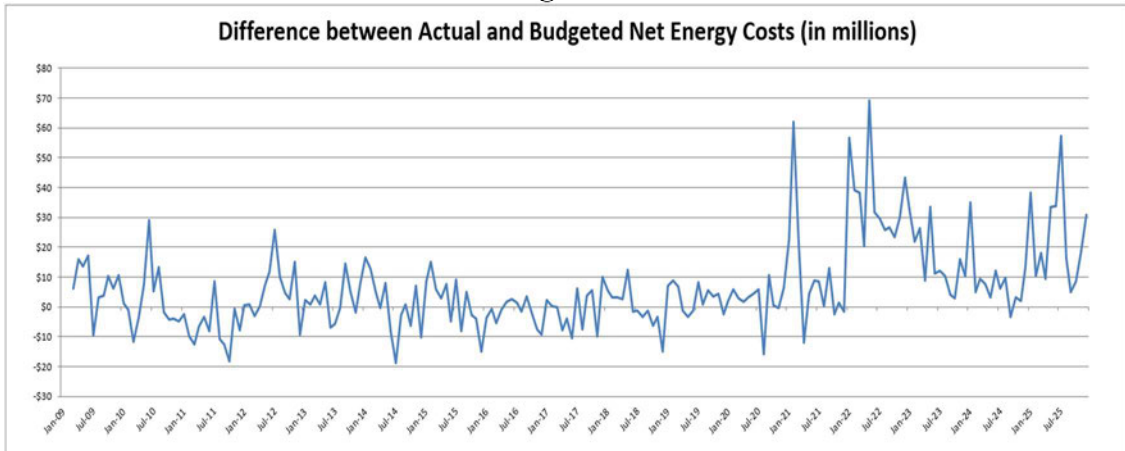
7 A. No, they do not. The Company does have defined strategies and hedging  
8 programs to manage commodity price exposures which include, but are not limited to coal  
9 & coal transportation, natural gas & pipeline services, nuclear fuel, rail surcharge for diesel,  
10 off-system sales, purchased power, electric congestion rights, and capacity positions.  
11 However, the Company has very little control over the underlying market prices and the  
12 volumetric components of ANEC. While hedging programs create fixed price points for  
13 commodities, the ultimate fuel or electric expenses are a function of price and volume. The  
14 Company's fuel and purchased power expenses, off-system sales, and spot market prices  
15 for fuel commodities and energy are inextricably linked together. Purchase power volumes  
16 fluctuate based on numerous drivers such as changes in native load obligations, generation  
17 fleet availability, and overall market prices. Similarly, off-system sales revenues are a  
18 function of that same unit dispatch and changes in native load obligations.

19 **Q. Does the Company's annual budgetary ANEC forecast, when**  
20 **compared to actual, demonstrate the volatility and uncertainty of ANEC?**

21 A. Yes. Figures 2 and 3 below show the variance between what we expected  
22 our ANEC to be (per our budget) and what the actual ANEC values have been historically.

1

**Figure 2**

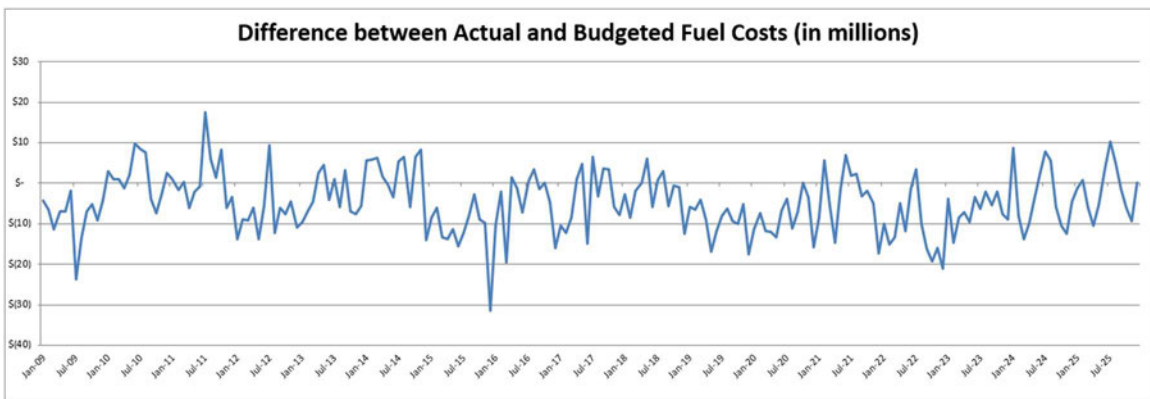


2

Figure 3 shows the same thing for only the fuel cost component of ANEC:

3

**Figure 3**



4

The volatility of ANEC (both up and down) is clearly visible in these charts. The

5

budget values used in this comparison are produced substantially closer to the actual

6

timeframe that the Company is incurring these costs and revenues, as compared to when

7

NBEC is reset in a general rate review. This budget process also utilizes projected costs,

8

whereas the FAC rules adopted by the Commission require the use of historic costs for

9

purposes of establishing NBEC. As such, one might expect the Company's budget forecast

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to not contain large variances. However, in actual practice, we see tens of millions of

1 dollars in differences between what we budget and what we experience, which  
2 demonstrates that these costs continue to be volatile and uncertain.

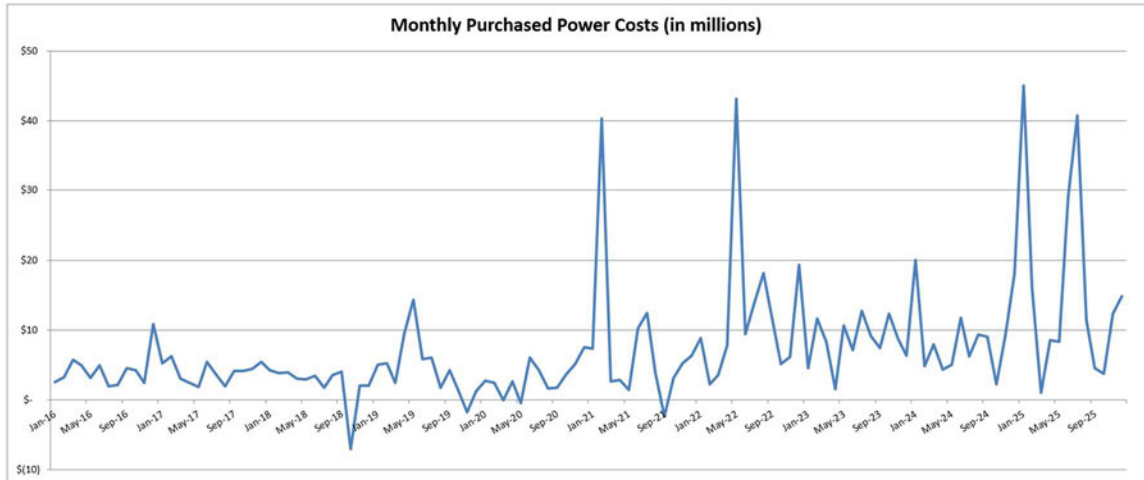
3 In summary, the extensive fuel and purchased power costs and substantial off-  
4 system sales revenues that we track in the FAC cannot be controlled by the Company and  
5 continue to be volatile and uncertain. I will discuss the volatility of market factors  
6 impacting FAC components later.

7 **Q. How have extreme weather events impacted commodity market**  
8 **pricing, and therefore ANEC?**

9 A. In the last several years we have seen multiple winter storms that have had  
10 a dramatic impact on the market price of natural gas and electricity. While for ratemaking  
11 purposes we have normalized the market price impacts of these storms out in some prior  
12 rate reviews, the frequency of these storms compels us to anticipate similar events in the  
13 future (since rates are set for the future) and not continue to exclude their impact when  
14 establishing NBEC and cost of service; i.e., to stop normalizing them because their  
15 occurrence has become normal. Figure 4 demonstrates the Company's monthly purchased  
16 power expenses. Some spikes in this monthly expense correlate well with extreme weather  
17 events, including Winter Storm Uri in February 2021 and Winter Storm Blair in January  
18 2025.

1

**Figure 4**



2

While not based on extreme weather, some of the spikes we can observe in Figure 4 were also caused in part by geopolitical events that also created similar commodity market disruption in the last several years. The invasion of Ukraine in 2022 and the recent conflict in Iran are examples of geopolitical events that influenced global commodity prices and supply.

7

**Q. Please explain how operating with an FAC still allows for a lag in time between the incurrence of fuel-related costs and recovery of those costs.**

8

9

A. Ameren Missouri's FAC recovery mechanism is designed to mitigate net energy cost-related rate impacts for customers. It accomplishes this by only allowing three updates per year, and by spreading the recovery, or return, of any differences over an eight-month period. As a result of these two features, there is a notable delay in the timely recoupment of fuel-related costs. Schedule AMM-D2 illustrates how it will take at least 12

13

1 months between the time when changes in ANEC occur and when those changes are fully<sup>6</sup>  
2 reflected in bills to customers.

3 **Q. Do other reasons support the necessary and appropriate continuation**  
4 **of the Company's FAC, beyond the discussion of magnitude, control, and**  
5 **volatility/uncertainty?**

6 A. Yes. Ameren Missouri's FAC remains critical to maintaining the  
7 Company's credit quality and keeping the Company's risk profile (with regard to this issue)  
8 on par with virtually all of the vertically integrated electric utilities across the country that  
9 operate with an FAC (including the other electric utilities in Missouri). The Commission  
10 has previously recognized that "[i]ncreased financial risk results in an increase in a  
11 company's cost of borrowing, ultimately increasing costs that will be passed on to  
12 ratepayers,"<sup>7</sup> and continued its recognition of the importance of an FAC to the investors  
13 (both debt and equity) that provide capital to the Company in its last fully litigated rate  
14 case order.<sup>8</sup> The facts that supported those findings have not changed.

15 **III. VOLATILITY AND UNCERTAINTY OF MARKET FACTORS**  
16 **IMPACTING FAC COMPONENTS**

17 **Q. Do the cost components of the FAC continue to be volatile and**  
18 **uncertain?**

19 A. Yes, all the cost and revenue components of the FAC continue to be volatile  
20 and uncertain. The commitment and dispatch of the Company's generating units in the

---

<sup>6</sup> The FAC does not provide "full" recovery because only 95% of the changes in net energy costs are reflected in FAC adjustments.

<sup>7</sup> File No. ER-2010-0036, *Report and Order*, p. 78, issued May 28, 2010.

<sup>8</sup> File No. ER-2014-0258, *Report and Order*, p. 103, issued April 29, 2015 ("Ameren Missouri still must compete in the capital markets with other utilities, and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness.").

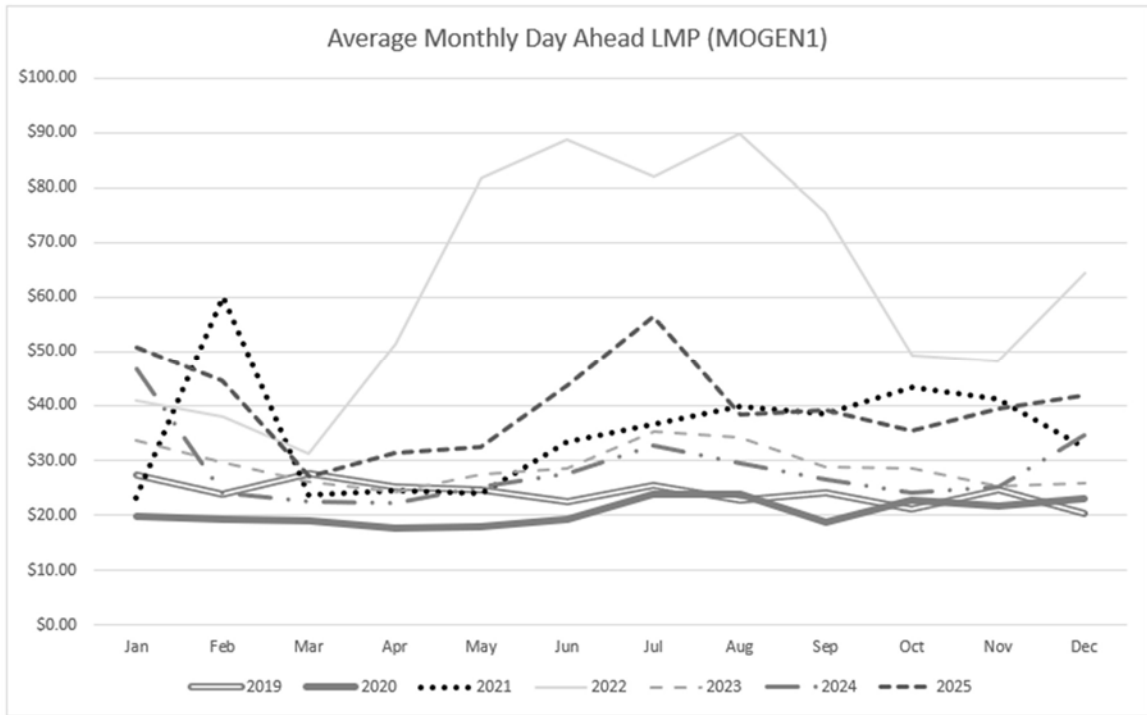
1 MISO market is a function of the offer price of the unit (based on its incremental fuel cost)  
2 and the market price available to the unit for a given hour. Any volatility or uncertainty in  
3 either the incremental fuel cost or the market price available to the units will consequently  
4 result in volatility and uncertainty in the unit output. The unit output ultimately impacts  
5 fuel & purchased power expense and off-system sales revenues.

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

7 A. Figure 5 below illustrates the variability in the wholesale market prices (i.e.,  
8 locational marginal prices or "LMPs") against which the Company's units are committed.  
9 The values are monthly averages of the Day-Ahead LMP for the MOGEN1 aggregate  
10 pricing node in MISO. This node is made up of the Labadie and Sioux Energy Centers. As  
11 this figure clearly shows, these LMPs show significant inconsistency from year-to-year.  
12 As previously noted, the impacts of severe weather events are evident in the pricing chart.  
13 Also, a 2022 pricing surge was evident in natural gas, where lower year-over-year  
14 inventories, strengthened international gas prices, and stagnant U.S. production all  
15 converged. Since natural gas is a fuel type that is frequently on-the-margin for MISO  
16 dispatch, the natural gas market impacts also manifest in electric pricing.

1

**Figure 5**



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

4           A.     Yes. The Company's hedging program effectively layered forward, fixed  
5 price contracts that deliver in a staggered manner from 2026 to 2030. However, the overall  
6 expense of delivered coal remains volatile and uncertain due to volume fluctuations and  
7 associated delivery surcharges and quality adjustments. The volume component is driven  
8 by the market dispatch of these units, which is itself a function of the incremental cost of  
9 fuel and market prices, while the price component is driven by the contracts for coal  
10 commodity and transportation.

1           **Q.     What adjustment factors impact the volatility and uncertainty of**  
2 **Ameren Missouri's coal and transportation costs?**

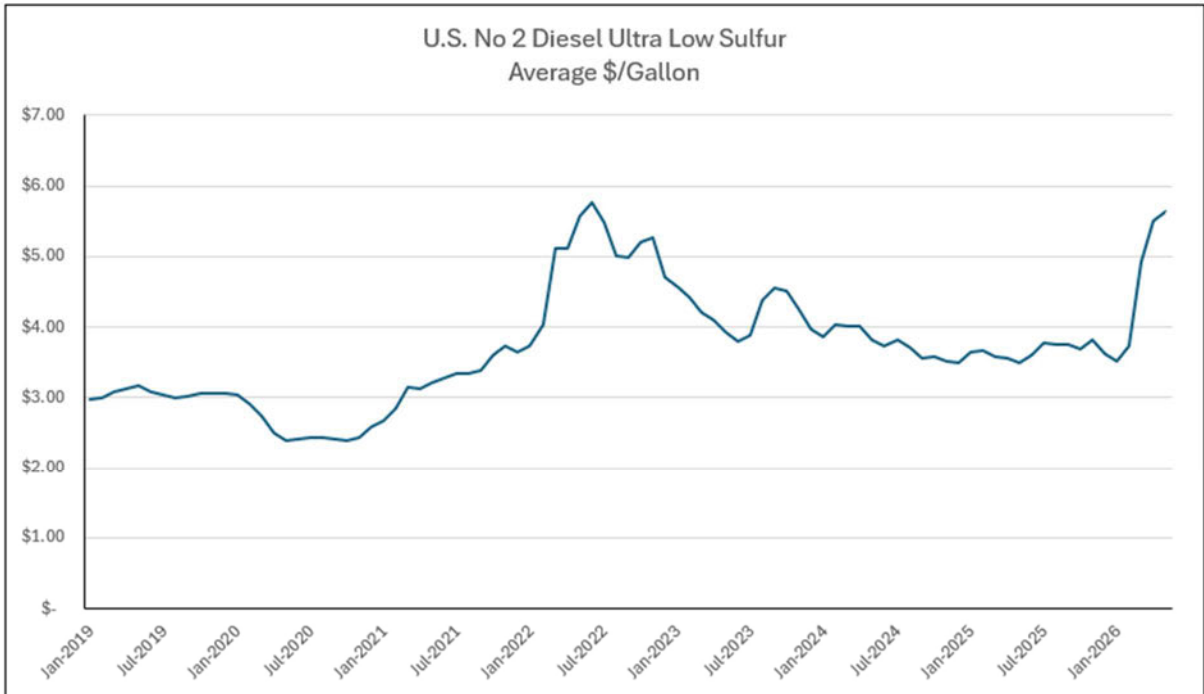
3           A.     The Company's coal commodity contracts include price adjustment  
4 mechanisms for British thermal unit (Btu) and sulfur dioxide (SO<sub>2</sub>) content. The various  
5 transportation agreements include provisions for rail surcharges (based on the price of  
6 diesel fuel), and escalators tied to the Association of American Railroads cost indices.

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

9           A.     Rail surcharges are variable costs of rail transportation which compensate  
10 the railways for their diesel fuel expenditures. This surcharge is based on On-Highway  
11 Diesel Fuel pricing, and if applicable, is also based upon car-miles traveled. Diesel prices  
12 have surged amid the war in Iran, increasing from \$3.52 per gallon on average in January  
13 2026 to \$5.64 per gallon on a weekly average basis by mid-May 2026. The following chart  
14 (Figure 6) shows the change in U.S. No 2 Diesel Ultra Low Sulfur price from January 2019  
15 to mid-May 2026.

1

**Figure 6**



2

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

7

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

8

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

10

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

12

A. Yes. The units in Ameren Missouri's natural gas generation fleet (also referred to as combustion turbine generators or "CTGs"), are peaking units. Their

13

1 generation output is significantly more variable and less predictable than that of baseload  
2 units, although baseload units' output is also subject to potential levels of variability as  
3 we've seen with the coal fleet historically.

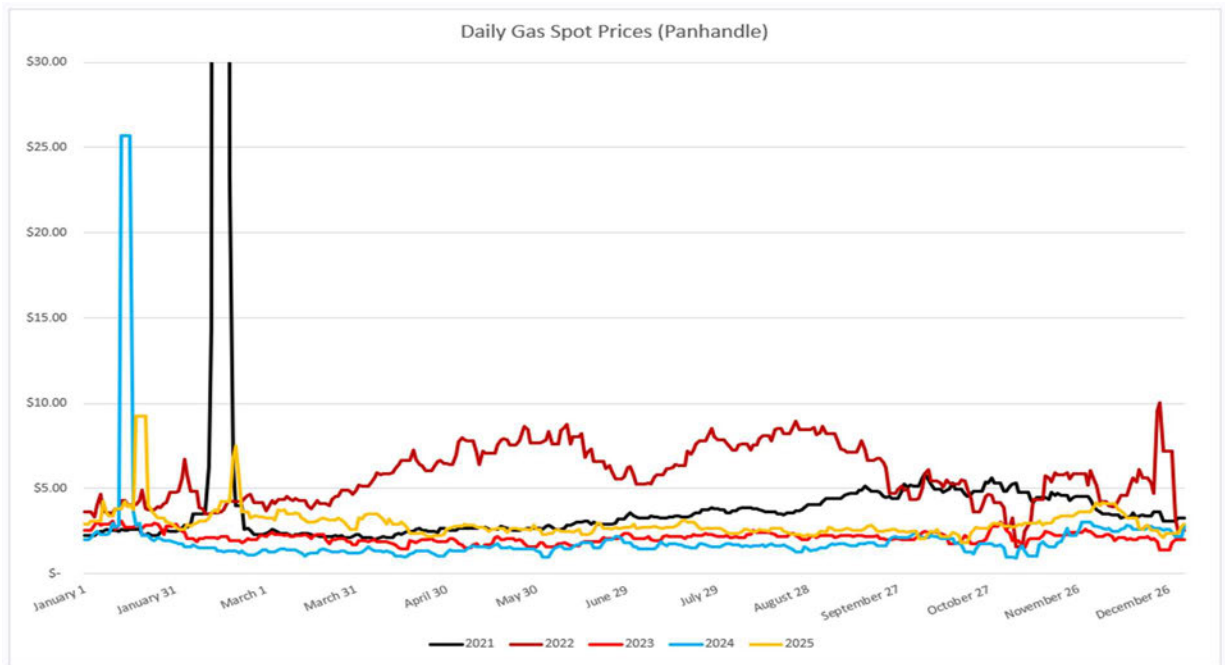
4 As a result, Ameren Missouri frequently procures natural gas supplies for its CTGs  
5 in the next-day or same-day gas markets. This is achieved once the unit has been committed  
6 by the MISO market. Natural gas prices have seen significant volatility in recent years.  
7 Even during periods of lower prices, significant daily and locational gas market volatility  
8 persists, particularly on peak days. Figure 7 below shows the daily spot price for the  
9 Panhandle Tx-Okla receipt point. This natural gas receipt point is key to Ameren  
10 Missouri's gas generation fuel supply, as multiple simple-cycle CTG plants are located on  
11 this supply path. From 2021 to 2025, daily spot prices showed notable volatility, spanning  
12 from \$224.56 on February 13, 2021 to \$0.95 on November 5, 2024.<sup>9</sup>

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<sup>9</sup> In Figure 7, the vertical axis was truncated to a max value of \$30, and the daily pricing witnessed during Winter Storm Uri in 2021 is not visible in the figure.

1

**Figure 7**



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

4 A. Yes, for all the reasons outlined above. This volatility and uncertainty are  
5 further compounded by sales volumes being driven by the volume of customer demand  
6 that is bid into the MISO market. The Company's demand is likewise volatile and uncertain,  
7 as it is driven to a significant degree by weather-related factors.

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

10 A. Ameren Missouri operates in a "buy all – sell all" RTO wholesale market.<sup>10</sup>  
11 As a function of the MISO market, all the generation which is cleared for a given hour is  
12 sold into the market. At the same time, the Company must purchase from the MISO market

<sup>10</sup> As noted earlier, the output of the Atchison Energy Center is sold into the Southwest Power Pool ("SPP") market, but all other generation is sold into the MISO market.

1 all the energy needed to meet its load obligations. Federal Energy Regulatory Commission  
2 ("FERC") Order 668 requires that these sales and purchases be netted against each other in  
3 each given hour. When the volume of purchases exceeds the volume of sales in a given  
4 hour, a net purchase is recorded. When the opposite occurs, a net sale is recorded.

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

6 A. Yes. The Company's activity in the MISO energy & ancillary market, while  
7 it optimizes off-system sales opportunities and provides opportunities for purchased power  
8 at prices below the Company's fleet dispatch costs, also creates exposure to volatile and  
9 uncertain energy pricing when system conditions are stressed. As previously discussed,  
10 the cost of purchased power during Winter Storms such as Uri in 2021, Elliot in 2022, Blair  
11 in 2025, or Fern in 2026, can be quite volatile and uncertain.

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

13 A. Yes. Ancillary services revenues arise through the Company's participation  
14 in the MISO market. The following Figure 8 shows ancillary services costs and revenues  
15 for regulation, spinning reserve, and supplemental reserve services from January 2018 to  
16 December 2025, reflecting a (full year) range from a net revenue of \$1.77 million in a given  
17 year to \$6.55 million in another year during this period. Ancillary services costs are a  
18 function of how much load the Company settles in the MISO market.

19 **Figure 8**

Ancillary Services	2018	2019	2020	2021	2022	2023	2024	2025
Cost (\$M)	\$3.26	\$2.39	\$2.09	\$4.07	\$4.02	\$4.03	\$4.82	\$10.25
Revenue (\$M)	(\$9.81)	(\$4.63)	(\$5.33)	(\$6.05)	(\$7.72)	(\$6.59)	(\$7.18)	(\$12.02)
Net (\$M)	(\$6.55)	(\$2.24)	(\$3.24)	(\$1.98)	(\$3.69)	(\$2.56)	(\$2.36)	(\$1.77)



1           A.     Reported off-system sales values exclude any revenues and expenses from  
2     the High Prairie Renewable Energy Center, the Atchison County Renewable Energy  
3     Center, and the Huck Finn Renewable Energy Center, all of which are operated for the  
4     primary purpose of complying with the Missouri Renewable Energy Standard and are  
5     therefore reflected in the Company's Renewable Energy Standard Rate Adjustment  
6     Mechanism.

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

9           A.     I determined that the following components of net off-system sales revenues  
10    that should be included in Ameren Missouri's revenue requirement and used to set NBEC  
11    in the FAC:

- 12           1)     \$159.2 million of off-system energy sales revenues;
- 13           2)     \$517 million of gross capacity sales revenues;
- 14           3)     \$12.9 million of ancillary services revenues;
- 15           4)     -\$0.19 million of virtual transaction margins.

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

17           A.     Ameren Missouri's normalized annual off-system sales of energy were  
18    calculated using the PowerSIMM production cost model, which is discussed in more detail  
19    in the Direct Testimony of Company witness Mike Flanagan.

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

22           A.     I have determined that \$517 million of gross capacity sales revenues and  
23    \$501 million of gross capacity purchase costs are the appropriate amounts to include in the

1 determination of NBEC. These values represent the average annual sales revenues and  
2 purchase costs for the last three MISO Planning Years (“PY”),<sup>11</sup> which cover the period of  
3 June 1, 2024, through May 31, 2027. Three years of seasonal PRA history were used to  
4 normalize the results, as the MISO PRA results are extremely volatile, as previously  
5 discussed. A normalization adjustment was made to remove revenues from any sales of  
6 Rush Island Energy Center, as it retired in Fall 2024 after several months as a System  
7 Support Resource. The Rush Island units cleared only for summer in the 2024-25 PRA.  
8 Additional normalization adjustments were made to add revenues from new generation  
9 resources that reached commercial operation during the three-year timeframe. These  
10 include Boomtown, Cass County, Bowling Green, Vandalia, Split Rail, and New Florence  
11 Renewable Energy Centers. A normalization adjustment was made to the gross capacity  
12 purchase costs, to reduce that cost by the value of any Zonal Deliverability Benefit ("ZDB")  
13 credits.

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

16 A. Based upon actual test year values, I have concluded the level of annual  
17 ancillary services revenues to include in total off-system sales is \$12.9 million, which is  
18 recorded in FERC account 447. There is an off-setting ancillary services expense of \$11.0  
19 million, which is recorded in FERC account 555.

20 **Q. What value does the Company recommend for MISO virtual**  
21 **transaction gains and losses in the calculation of NBEC?**

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<sup>11</sup> Planning years run from June 1 to May 31.

1           A.     The recommended value is -\$185,826. For the same reasons that Company  
2 is not recommending normalization of winter storm impact, because they have become  
3 relatively routine, the recommendation for virtual margin gain and losses used to set NBEC  
4 in the FAC is only for the test year period.

5                   **V.     RIDER FAC UPDATES AND KEY COMPONENTS**

6           **Q.     Has the Company made any updates or changes to the Rider FAC tariff**  
7 **as filed in this case?**

8           A.     The Company is only proposing the following necessary updates to the FAC  
9 to account for changed values since the FAC was last approved:

- 10           a.     Use of updated Base Factor ("BF") amounts using updated NBEC figures.
- 11           b.     Updating the transmission percentage to be included in the FAC, consistent  
12 with the method for doing so previously approved by the Commission.
- 13           c.     Add, pursuant to the Stipulation and Agreement approved by the  
14 Commission in File No. ET-2025-0184, and further clarify the exclusion from the FAC of  
15 wholesale capacity expenses and revenues related to certain capacity transactions  
16 undertaken as a result of contractual provisions of large load customers' Electric Service  
17 Agreements ("ESAs").
- 18           d.     Add applicability of FAR charges to Rate 14(M), which is the newly created  
19 rate schedule for large load customers (those having previously been a subclass under Rate  
20 11(M)).
- 21           e.     Updating the FAC Charge Type Table to reflect new charge types, for which  
22 notice was properly given under the Commission's FAC rule, that have been added since  
23 the Company's last rate review.

1 A redlined version of the current Rider FAC showing the above-described changes is  
2 attached to my testimony as Schedule AMM-D3.<sup>12</sup>

3 **Q. Has the Company also rebased the NBEC used to calculate the BF<sup>13</sup> in**  
4 **the FAC tariff to reflect the current level of NBEC?**

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

10 In the Company's previous rate case, File No. ER-2024-0319, the Commission set  
11 the BF at 1.421 cents per kilowatt-hour ("kWh") for the summer and 1.383 cents per kWh  
12 for the winter, based on the NBEC in the revenue requirement in that case. We are  
13 proposing to update the BF to 1.600 cents per kWh for the summer and 1.375 cents per  
14 kWh for the winter. The calculation of the NBEC that underlies these BF values is  
15 addressed in detail in the Direct Testimony of Company witness Stephen J. Hipkiss.

16 **Q. Please explain the proposed exclusion for certain capacity**  
17 **transactions undertaken as a result of contractual provisions of the large load**  
18 **customer tariff.**

19 A. In the large load tariff case, File No. ET-2025-0184, the Stipulation and  
20 Agreement approved by the Commission called for changes to be made in the Company's

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<sup>12</sup> Please note that four SPP charge types that had previously been properly noticed and added were inadvertently included in the current version of Rider FAC with the MISO charge types but should have been listed as SPP charge types. We have shaded those relocated charge types in yellow in Schedule AMM-D3. The additional charge types noticed and added are shaded in green. We have also alphabetized the SPP charge types in the table, but only those in green have been added.

<sup>13</sup> Factor BF is determined by dividing the B (which is expressed in dollars) by the total normalized net system load to produce a rate.

1 next general rate case to exclude capacity transactions from the FAC where those  
2 transactions are undertaken as a result of two specific types of circumstances that may arise  
3 under the large load customer tariff and the related large load customers' ESAs. The  
4 exclusion of these transactions from the FAC will eliminate the potential to double-count  
5 the transactions in a manner that could result in existing customers paying costs or  
6 receiving benefits that are solely tied to large load transactions. The tariff provisions being  
7 added to the FAC in this case are being included in compliance with that order. However,  
8 the Company is proposing some clarifications to the language that was included in the  
9 illustrative FAC tariff attached to that Stipulation and Agreement in order to more clearly  
10 define the specific types of contractual arrangements that will give rise to capacity  
11 transactions that are to be excluded from the FAC.

12         The first change excludes from the determination of the FAR any capacity sales  
13 revenues that arise from capacity that is available for sale as a result of a large load  
14 customer termination or capacity reduction, and for which the Company is providing  
15 capacity sales revenue to the large load that terminated or reduced its contract demand as  
16 a mitigation of the termination or capacity reduction fees. All customers will have benefited  
17 from the termination or capacity reduction fee revenues, and therefore the large load  
18 customer itself will receive the market revenues from the capacity that it has "paid for" as  
19 a mitigation of the charges it incurred. This treatment is expressly provided for in the large  
20 load customer tariff.

21         The next change relates to a provision in the Company's large load tariff that  
22 contemplates that large load customers will pay for capacity that the Company's then-  
23 existing system capabilities cannot meet (due to the customer's new entry onto the system)

1 for an interim period until the Company is able to increase its own system capacity to serve  
2 them on an ongoing basis. It is necessary to exclude the costs of that interim capacity,  
3 including purchases made through the MISO PRA as well as bilateral purchases, along  
4 with the net settlement of those purchases and the load obligation being served, from the  
5 FAC, so that only the large load customers pay for it. Under the large load tariff, the cost  
6 of interim capacity is to be paid by the large load customer pursuant to an additional  
7 demand charge as part of their electric service bill, and including those same costs in the  
8 FAC would negatively impact existing customers and result in the double recovery of  
9 capacity costs.

10 **Q. Does this conclude your Direct Testimony?**

11 **A. Yes, it does.**



## FAC MINIMUM FILING REQUIREMENTS<sup>1</sup>

- (A) An example of the notice to be provided to customers as required by 20 CSR 4240-20.090(2)(A)1;

### LOCAL PUBLIC HEARING NOTICE

Ameren Missouri has filed a rate increase request with the Missouri Public Service Commission (“PSC”). The increase would total approximately \$343 million, or approximately 10.44%, in the territory served by Ameren Missouri. For the average residential customer, the proposed increase would be about \$12.88 per month.

Ameren Missouri’s FAC allows Ameren Missouri to adjust customers’ bills three times per year based on the varying cost of fuel and power purchased net of off-system sales (“net energy costs”) in the current volatile market. Any increase or decrease in net energy costs is reflected in the FAC. This means the customer bill is based on more current net energy costs. The FAC adjustment is applied to customers’ bills based on the customer’s usage. The overall increase sought in this case contemplates a rebasing of net energy costs tracked in the FAC. The rebasing reflects an increase in net base energy costs of approximately \$29.7 million. If the net energy costs had not been rebased in this case, the base rate increase that would have been proposed in this case would have been smaller.

The PSC has set \_\_ local public hearings, \_\_ virtual and \_\_ in person.

The PSC may limit the time for testifying at each hearing to three minutes per person.

In person hearings will be at facilities that meet the accessibility requirements of the Americans with Disabilities Act. Any person who needs additional accommodations to participate in this hearing should call the Public Service Commission’s hotline at 1-800 392-4211 (voice) or TDD Hotline 1-800-829-7541 at least three days prior to the hearing.


<sup>1</sup> Each item (1) .... (19) corresponds to the subparagraphs in 20 CSR 4240-20.090(2)(A).

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Date/Time	Location	Access
	WebEx	
	WebEx	

To attend online, going to the website at [www.webex.com](http://www.webex.com) or download Cisco WebEx Meetings application. At hearing time enter the meeting code and password. To attend by telephone, call toll free 1-855-718-6621. When prompted, enter the meeting code by the #. If prompted for a password, enter 0143. To facilitate an orderly presentation that can be preserved for the record, members of the public who wish to testify at a virtual public hearing should register, but are not required to register, by sending their first and last name, phone number, email address, and the hearing they wish to testify to [pscinfo@psc.mo.gov](mailto:pscinfo@psc.mo.gov), or by calling (800) 392-4211 by 5:00 p.m. the day before the hearing. Comments Regardless of whether you testify, you may provide comments, which may not be evidence, by submitting them to the Commission in writing by mail to the Missouri Public Service Commission, P.O. Box 360, Jefferson City, Missouri 65102, or electronically using the Commission's electronic filing system at [https://psc.mo.gov/General/Submit\\_Comments](https://psc.mo.gov/General/Submit_Comments). When submitting comments please reference Case No. ER-2026-0143. Comments may also be made to the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone 573-751-4857 or tollfree 866-922-2959, [opcservice@opc.mo.gov](mailto:opcservice@opc.mo.gov). Comments are viewable by the public. Do not include any information in a public comment that you do not wish to be made public.

- (B) An example customer bill(s) covering all of the electric utility's rate classes showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with 20 CSR 4240-20.090(2)(A)2;

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

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

Included in the tariffs submitted in this case is Rider FAC - Fuel and Purchased Power Adjustment Clause, which are the proposed tariff sheets reflecting the fuel adjustment clause proposed by Ameren Missouri.

- (D) A detailed description of the design and intended operation of the proposed RAM in accordance with 20 CSR 4240-20.090(2)(A)4;

As discussed in the testimony to which this Schedule is attached, Ameren Missouri is proposing to continue its existing FAC in substantially its current form. The FAC applies to all rate classes, and would reflect increases or decreases in fuel and purchased power costs, including transportation<sup>2</sup> and emissions costs and revenues, net of off-system sales revenues (“actual net energy costs”), according to the formula expressed in the tariff sheets referred to in item (C) above.<sup>3</sup> Historic fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues, would be accumulated during three different Accumulation Periods, as designated in the rate schedule, and then 95% of the change in actual net energy costs would be recovered (if an increase) or credited (if a decrease) using the calculated FAR (as defined in the rate schedule) over three different Recovery Periods (also designated in the rate schedule), each of which cover a period of eight months. Two of the three changes to the FAR would coincide with the existing seasonal changes in Ameren Missouri’s base rates. The tariff includes three seasonal base amounts, known as the “base factor” (factor BF in the tariff), against which changes in actual net energy costs are tracked. The FAR would be applied to customer bills on a per kilowatt-hour (“kWh”) basis, as adjusted for voltage level (to take into account varying line losses at different service voltage levels). As discussed in the testimony to which this schedule is attached, there are four different voltage adjustment factors (one applicable to customers taking service at secondary voltage; three for primary service customers), consistent with the agreement reached in the stipulation that resolved the Company's last electric rate review.

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

- (E) A detailed explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity in accordance with 20 CSR 4240-20.090(2)(A)5;

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

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<sup>2</sup> Consistent with the current Rider FAC and the Rider FAC filed in this docket, some transmission charges are excluded from the FAC. However, since some transmission charges (and revenues) remain in the FAC this schedule will refer to transportation including associated with purchased power.

<sup>3</sup> As reflected in the current Rider FAC and the Rider FAC filed in this docket, costs and revenues that would otherwise constitute net energy costs tracked in the FAC that arise from the Atchison, High Prairie, and Huck Finn Energy Centers, which are used to comply with Ameren Missouri’s obligations under Missouri’s Renewable Energy Standard, are not reflected in net energy cost in the FAC but instead are reflected in the Company’s Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM).

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

- (F) A detailed explanation of how the proposed FAC shall be trued-up for over- and under-billing, or how and when the refundable portion of the proposed IEC shall be trued-up in accordance with 20 CSR 4240-20.090(2)(A)6;

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

True-up amounts will reflect the difference between the Fuel and Purchased Power Adjustment ("FPA" as defined in the calculation of the FAR provided for in the FAC tariff) authorized for recovery under the FAC for the subject recovery period and FAR customer revenues actually billed. FAR customer revenues can vary from those expected in calculating the FAR because of variations in the actual kWh sales during a given recovery period versus the estimated kWh sales used to set the FAR in effect during a given recovery period. Additionally, the FAR calculated can vary from the amount originally authorized due to updates of factor "SAP," as defined in Rider FAC. Updates to factor SAP occur as a result of S105 Midcontinent Independent System Operator, Inc. ("MISO") settlement statements.<sup>4</sup> The MISO settlement statements provide the kWh data for the amount of

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<sup>4</sup> "S105" stands for 105 days after the end of the period covered by the settlement statement.

energy Ameren Missouri purchased to serve its load zone and is multiplied by factor “BF,” as defined in Rider FAC, to determine the dollars of net energy costs billed through base rates (factor “B”) used to calculate the FPA.

- (G) A detailed description of how the electric utility’s short-term borrowing rate will be defined and how it will be applied, during the accumulation period and the recovery period, to over- and under-billed amounts and prudence disallowances in accordance with 20 CSR 4240-20.090(2)(A)7;

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

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

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

- (H) A detailed description of how the proposed RAM is compatible with the requirement for prudence reviews in accordance with 20 CSR 4240-20.090(2)(A)8;

Ameren Missouri’s FAC is compatible with the requirement for prudence reviews for several reasons, as evidenced by the completion to-date of eleven prudence reviews. Ameren Missouri’s FAC is based on actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of actual off-system sales revenues, which simplifies the prudence review. The fuel and purchased power costs included in the FAC are well defined in Rider FAC (the FAC tariff), including specific references to the FERC accounts in which the costs are recorded. Moreover, 20 CSR 4240-20.090(5), requires the filing monthly of all the supporting data for the fuel and purchased power costs, revenues, plant generation, and related information, all of which can be used as part of the prudence review process. These reports are currently being submitted by Ameren Missouri on a monthly basis. This includes providing monthly fuel burn and generating statistics for each of the generating plants. In addition, 20 CSR 4240-3.190 requires submission to the Commission Staff each month of information on system output, hourly generation, purchases and sales, planned outages, forced outages, and capacity purchases.

All contracts for fuel, transportation, and purchased power will also be available for review in connection with the prudence review process. The prudence review could also be used in conjunction with an audit plan, through which appropriate financial data can be sampled from the fuel and fuel transportation invoices that will be available.

- (I) A detailed explanation of the fuel and purchased power costs, including transportation, that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the Commission where the cost will be recorded on the electric utility's books and records in accordance with 20 CSR 4240-20.090(2)(A)9;

These costs<sup>5</sup> are explained below and in tables included as Attachment F<sup>6</sup> to this Schedule:

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

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

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

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

**Fuel Additives.** Cost of consumables such as urea, limestone, and powder activated carbon used to operate Air Quality Control Systems (AQCS). These costs are accumulated

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<sup>5</sup> These cost categories can also include revenues, as provided for in Rider FAC, but are reflected in FERC accounts for costs and, on a net basis, reflect costs.

<sup>6</sup> The descriptions in Attachment F reflect current accounting, including managerial accounting, for these items. The descriptions/accounting may change over time.

in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

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

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

**Cost of Purchased Power.** This will include the cost at the point of receipt by the Company of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy or on-peak energy, ancillary services, etc. In addition, this category will include costs incurred from regional transmission organizations (“RTOs”) for Revenue Sufficiency Guarantee, losses, deviation charges, revenue neutrality, inadvertent charges, congestion and firm transmission rights but shall exclude administrative costs arising under MISO Schedules 10, 16, 17 and 24, and SPP schedules 1A and 12, and shall exclude capacity charges under contracts with a term in excess of one (1) year.

**Transmission Costs.** 100% of transmission costs to either transmit electric power sold to third parties (off-system sales), or to transmit electric power on a non-MISO system (excluding costs identified as administrative charges). In addition, 9.22% of transmission service charges recorded in FERC account 565 associated with Ameren Missouri's network transmission service (excluding costs identified as administrative charges) have been included, consistent with the methodology approved by the Commission in File No. ER-2014-0258 and subsequently.

**Emissions Allowances.** Costs and revenues for SO<sub>2</sub> and NO<sub>x</sub> emissions allowances, including those associated with hedging.

- (J) A detailed explanation of the fuel-related revenues that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the Commission where the revenue will be recorded on the electric utility's books and records in accordance with 20 CSR 4240-20.090(2)(A)10;

These revenues<sup>7</sup> are explained as follows and in the tables included as Attachment F<sup>8</sup> to this Schedule:

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

**Transmission Revenues.** 9.22% of transmission revenues recorded in FERC account 456.1 have been included, consistent with the methodology approved by the Commission.

- (K) A detailed explanation of any incentive feature in the proposed RAM and the expected benefit and cost each feature is intended to produce for both the electric utility and its Missouri retail customers in accordance with 20 CSR 4240-20.090(2)(A)11;

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

- (L) A detailed explanation of any rate volatility mitigation feature in the proposed RAM in accordance with 20 CSR 4240-20.090(2)(A)12;

Ameren Missouri's proposed FAC spreads the recovery of the difference between the base energy costs set in the rate proceeding and fuel costs during each Accumulation Period over a full 8-month period. This has a mitigating effect on rate increases or decreases that will occur as a result of the three periodic FAC adjustments each year. Moreover, as discussed in Item (M) below, Ameren Missouri utilizes a hedging strategy designed to mitigate fuel cost volatility. Moreover, the FAC is seasonally adjusted and contains seasonally differentiated net base fuel costs. This results in tracking higher actual fuel costs against higher base fuel costs (in the Winter) and lower actual fuel costs against lower base fuel costs (in the Summer), both of which tends to mitigate volatility.

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<sup>7</sup> These revenue categories can also include costs, as provided for in Rider FAC, but are reflected in FERC accounts for revenues and, on a net basis, reflect revenues.

<sup>8</sup> The descriptions in Attachment F reflect current accounting, including managerial accounting, for these items. The descriptions/accounting may change over time.

- (M) A detailed explanation of any feature of the proposed RAM and any existing electric utility policy, procedure, or practice that ensures only prudent fuel and purchased power costs and fuel-related revenues are recovered through the proposed RAM, including, but not limited to, utilization of competitive bidding or other sourcing or sales practices in accordance with 20 CSR 4240-20.090(2)(A)13;

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

#### Fuel and Power Accounting

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

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

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

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

**Purchased Power.** For electricity purchased and sold within the MISO and SPP markets, Ameren Missouri utilizes the PCI system. This system maintains the detailed charges and statistics pulled directly from the MISO and SPP Portals. It gathers Company-provided

inputs (e.g., meter data) and RTO-provided data and performs a parallel calculation of expected charges. This recalculation serves as the primary control concerning RTO charges and is performed daily. On a monthly basis, the data is downloaded from PCI, reviewed, and approved prior to posting in the general ledger. Power purchased and sold outside the MISO and SPP markets is recorded in the trade management system called Endur, maintained by risk management. These entries are reviewed and approved prior to posting to the general ledger monthly. All receivable and payable accounts associated with power are balanced on a monthly basis.

**Transmission of Electricity.** MISO bills transmission customers and distributes revenues to transmission owners, including Ameren Missouri, directly through monthly settlement files. The settlement files are downloaded from the MISO portal. A Transmission Policy Specialist creates a monthly summary file assigning the corresponding accounting to the revenues and expenses based on the schedule for each market participant. The Transmission Policy Specialist researches any exceptions and determines whether the exception requires a dispute to be filed with MISO. Once satisfied, the Transmission Policy Specialist sends the validated summary file to Power Accounting. Power Accounting uses the monthly summary file to record monthly transmission revenues and expenses in the general ledger based on the MISO schedule and market participant. These entries are reviewed and approved prior to posting to the general ledger monthly. All receivable and payable accounts associated with power are balanced on a monthly basis.

#### Fuel and Power Procurement

**Fossil (e.g., coal and natural gas):** To ensure fuel purchases are prudent, the fuel acquisition for Ameren Missouri's generation is governed by the Ameren Missouri Commodity Risk Management Policy ("Policy"). The rules and guidelines within the Policy, which were approved by Ameren's Risk Management Steering Committee, identify the levels of coal and natural gas for generation that must be acquired and hedged for future periods, identify the various types of allowable commodity transactions, and create extensive management reporting to monitor commodity transactions and price positions. The Policy provides that coal and natural gas be purchased using a risk management strategy that secures the required volume for future periods within maximum and minimum Policy limits while reducing exposure to market volatility. Deviations to the Policy are allowed when justified by business conditions but must be approved by the Risk Management Steering Committee. The volumetric risk (securing the necessary quantities of fuel needed for electricity production) and price risk (entering into financial and physical transactions to hedge against price spikes and volatility in the market) for generation fuels are controlled through compliance with the Policy limits. The Policy does not necessarily result in the lowest possible price for fuel, but strikes an appropriate balance between price stability and security of supply. In addition to the Policy, there are annual fuel supply planning processes which determine the actual acquisition of fuel for generation needs from various production basins and other parameters of fuel supply including transportation, inventory levels, management of inventory levels through purchases and sales, and logistics with power plants/power traders/generation dispatchers. These processes also encompass the development of competitive or alternative transportation

methods between transportation providers to ensure competitive and reliable fuel supply. To ensure competitive fuel supply in the commodity markets, the fuel is procured and hedged through several diverse methods including periodic competitive bids, negotiated purchases, electronic trading, Over-the-Counter (“OTC”) transactions, futures market transactions, and spot market transactions. In addition to the Policy and fuel planning processes, the Internal Audit Department conducts audits of the Fuel Adjustment Clause periodically, based on a risk-based audit plan, for purposes of reporting to senior executives and the Board of Directors. Fuel for generation is purchased by Ameren Missouri personnel, which is staffed with full-time fuel professionals to manage all aspects of fuel supply and operations with a mission of delivering reliable and competitive fuel supply for Ameren Missouri.

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

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

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

**Purchased Power:** As a vertically integrated utility operating in the MISO market,<sup>9</sup> Ameren Missouri offers all generation for sale into the market and buys energy to supply all its obligations on a daily basis. The Company reports these amounts consistent with the Uniform System of Accounts, as revised by FERC Orders 668 and 668-A. Should the netted position of these two activities result in the Company being a net purchaser, a net charge is shown in FERC Account 555. All RTO-related activity is retrieved from the appropriate RTO Portal and validated using PCI software. In addition to these net purchased power costs from MISO settlements, FERC Account 555 includes several other costs related to purchasing similar services or purchases made outside the MISO market. The Company requires all commodity transactional activity be entered into risk management software. The Company performs a control process daily to validate appropriate transactional processing.

- (N) A detailed explanation of any change to the electric utility's business risk resulting from implementation of the proposed RAM, in addition to any other changes in business risk the electric utility may experience in accordance with 20 CSR 4240-20.090(2)(A)14;

Continuing the RAM will not change Ameren Missouri's business risk. The continuation of a fuel adjustment mechanism (the proposed RAM) would continue to allow Ameren Missouri to pass through to its customers increases and decreases in net energy costs without the need for a costly and time-consuming rate proceeding necessitated by changes in net energy costs. Prior to adoption of FACs for eligible Missouri utilities, the lack of a fuel adjustment mechanism in Missouri had been a major concern to the financial community because net energy costs have been highly volatile. Because fuel adjustment clauses predominantly are part of the regulation of other U.S. utilities, continuing a fuel adjustment mechanism will keep the business risk of Ameren Missouri more comparable to the risks of other utilities. Without a fuel adjustment mechanism, the business risk of Ameren Missouri would be higher than that of other utilities, all else being equal. However, since most of the electric utilities used in the sample groups of comparable companies in Ameren Missouri's cost of equity studies are able to recover their fuel costs through fuel adjustment clauses, the reduced risk of implementing the proposed RAM in Missouri is already reflected in Ameren Missouri's base cost of equity recommendation (10.25%) in this case. Ameren Missouri witness Ann Bulkley addresses the FAC and business risk in her direct testimony.

- (O) A level of efficiency for each of the electric utility's generating units determined by the results of heat rate/efficiency tests or monitoring that were conducted or obtained on each of the electric utility's steam generators, including nuclear steam generators, heat recovery steam generators, steam turbines and combustion turbines within twenty-four (24) months preceding the filing in accordance with 20 CSR 4240-20.090(2)(A)15;

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

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<sup>9</sup> Ameren Missouri's Atchison County wind energy facility sells its output into the Southwest Power Pool market.

- (P) Information that shows that the electric utility has in place a long-term resource planning process in accordance with 20 CSR 4240-20.090(2)(A)16;

On September 26, 2023, Ameren Missouri made its most recently required triennial Integrated Resource Plan (“IRP”) filing (EO-2024-0020), reflecting that important objectives of Ameren Missouri’s IRP process are to minimize overall delivered energy costs and provide reliable service while accelerating the transition to cleaner energy generation, together with a focus on the sufficiency of resources to meet customer needs, including during extreme weather events. This filing covers Ameren Missouri’s long-term resource planning process and consists of multiple volumes. Ameren Missouri’s IRP filing reflected analyses for a number of resource options and portfolios, and also examined the Company’s capacity position and needs in detail. This information included Ameren Missouri’s load forecasts as well as its analysis of available supply-side and demand-side resource options. The end result is a twenty-year resource plan and contingency options. The IRP filing was made in compliance with 20 CSR 4240-22.010, et. seq. This very comprehensive Commission rule is designed to ensure utilities provide energy services which “... are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.”<sup>10</sup> Ameren Missouri will next file a triennial IRP by October 1, 2026.

- (Q) A detailed explanation of Ameren Missouri’s emissions management policy, and its forecasted environmental investments, emissions allowances purchases, and emission allowances sales in accordance with 20 CSR 4240-20.090(2)(A)17;

Ameren Missouri has an established compliance strategy for the Cross State Air Pollution Rule ("CSAPR"), initially finalized by USEPA in July 2011 and subsequently revised. Ameren Missouri’s strategy for SO<sub>2</sub> compliance is to continue operation of the wet flue gas desulfurization ("FGD"), or "scrubber" systems, at the Sioux Energy Center coupled with purchase of ultra-low sulfur coal for the balance of our coal fired units at Labadie and Sioux (coupled as needed for operational reasons with Illinois coal at Sioux). In addition, all units at Meramec ceased operation in 2022 and Rush Island will cease operation in October 2024, resulting in a significant reduction in SO<sub>2</sub> emissions from the fleet overall.

Ameren Missouri’s strategy for compliance with both the annual and ozone season CSAPR NO<sub>x</sub> trading programs is for continued combustion of Power River Basin ("PRB") sub-bituminous coals and the operation and optimization of low NO<sub>x</sub> burner ("LNB") and over-fire air ("OFA") systems in conjunction with the installed neural net optimization systems at the Labadie coal-fired energy center. These systems, along with the combustion of PRB coals minimize NO<sub>x</sub> emissions. In 2023, as a result of the St. Louis Area's "bump up" to moderate nonattainment for the 2015 ozone standard, Ameren Missouri was required by MDNR to enter into an agreement to meet "Reasonably Achievable Control Technology (RACT) limits for NO<sub>x</sub> emissions at Labadie and Sioux. The Labadie NO<sub>x</sub> RACT Consent Agreement requires each Labadie Unit to meet a 0.12 lbs. NO<sub>x</sub>/mmBtu monthly average

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<sup>10</sup> 20 CSR 4240-22.010(2).

during each ozone season beginning in 2024. NOx RACT was not required at Rush Island due to the pending shutdown of the Rush Island units.

The Sioux NOx RACT Consent Agreement determines that RACT for the Sioux Units is operation of the installed selective non-catalytic reduction ("SNCR") systems. These systems have been maintained and are operational and have been available for use when additional NOx reduction has been needed at those units during the ozone season to keep systemwide NOx emissions at or below CSAPR allowance levels. During the 2023 (and previous) ozone seasons, the cost of operation of the SNCR systems has been compared to the cost of purchasing additional NOx allowances to determine the most cost-effective compliance approach. For the 2024 ozone season, SNCR operation is required by the Sioux NOx RACT Consent Agreement. As a result of the NOx RACT Consent Agreements, Ameren Missouri does not currently anticipate that significant purchases of ozone season NOx emissions allowances will be required to comply. In April 2023, the USEPA finalized changes to the CSAPR ozone season NOx trading program regulations. Those changes were challenged in federal district courts of appeal and are currently stayed in Missouri and eleven other states (12 total). Ameren Missouri is evaluating strategies for compliance with the latest CSAPR changes that could impact ozone season NOx allocations in future years.

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

With respect to the Company's forecasted capital investments, see Chapter 5 of the Company's 2023 triennial IRP.

- (R) Graphs accompanied by the data supporting the graphs for each month over the immediately preceding five years, showing the monthly equivalent availability factor, the monthly equivalent forced outage rate, and the length and timing of each planned outage for each of the Company's generating units are contained in Attachment G in accordance with 20 CSR 4240-20.090(2)(A)18;<sup>11</sup>
- (S) The Company authorizes the Staff to release to all parties to this case its previous five years of historical surveillance monitoring reports in accordance with 20 CSR 4240-20.090(2)(A)19.

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<sup>11</sup> The Company's direct case workpapers to be provided to the parties to this case contain the data underlying these graphs.



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[Redacted]

[Redacted]

[Redacted]

**AMOUNT DUE \$67.01**

The amount of this bill will be automatically deducted from your bank account 06/10/2026.

**Due Date 06/10/2026**

Amount After Due Date \$67.73

Previous Statement \$64.98

Total Payments \$64.98

*Payment Received. Thank You.*

[Redacted]

[Redacted]

**Current Detail for Statement 05/19/2026**

Total Electric Charges \$67.01

**Total Amount Due \$67.01**

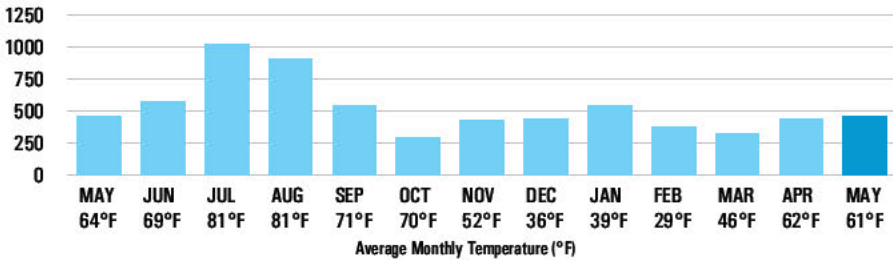
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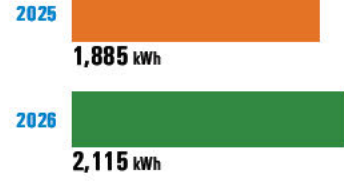
**Electric Usage History**

**Electric Usage in Kilowatt Hours (kWh)**



**Electric Usage Summary (kWh)**

So far this year you're using **12.2% more** than the same time period last year.



04998 2492339 009878 019955 0001/0002



» See next page for service details.

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Page 1 of 4

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<b>Amount Due</b>	<b>Due Date</b>
\$67.01	June 10, 2026
<b>Delinquent Amount After Due Date</b>	<b>Account Number</b>
\$67.73	[Redacted]

Amount Enclosed \$ \_\_\_\_\_



>004998 2492339 0001 092139 10Z  
04998 1 SP 0.78

[Redacted]

[Redacted]



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**Electric Service Details** Service from 04/16/2026 - 05/17/2026 (31 days)

**Electric Meter Read**

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
██████	04/16 - 05/17	31	Total kWh	Actual	27429.0000	26974.0000	455.0000	1.0000	455.0000

**Usage Summary**

Total kWh	455.0000	Non-Summer kWh	455.0000
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**Rate 1M Residential Anytime User**

DESCRIPTION	USAGE	UNIT	RATE	CHARGE
Winter Elec Energy Chg 0-750	455.00	kWh	@ \$ 0.10620000	\$48.32
Customer Charge				\$9.19
Fuel Adjustment Charge	455.00	kWh	@ \$ 0.00540000	\$2.46
Energy Efficiency Investment Charge	455.00	kWh	@ \$ 0.00190500	\$0.87
Renewable Energy Adjustment	455.00	kWh	@ \$ 0.00207000	\$0.94
Rush Island Retirement Cost	455.00	kWh	@ \$ 0.00118000	\$0.54
<b>Total Service Amount</b>				<b>\$62.32</b>
DESCRIPTION	USAGE	UNIT	RATE	CHARGE
Webster Groves Municipal Charge - Service	\$62.32		@ \$ 0.07527000	\$4.69
<b>Total Tax Related Charges</b>				<b>\$4.69</b>
<b>Total Electric Charges</b>				<b>\$67.01</b>

**Payments Since Previous Statement**

DATE RECEIVED	AMOUNT
May 11, 2026	\$64.98

Questions? Contact Ameren Missouri at 1.800.552.7583 or visit AmerenMissouri.com.

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AMOUNT DUE

\$67.01

Due Date

06/10/2026

Attachment A

### Account Messages

A late payment charge of 1% will be added for any unpaid balance on all accounts after the due date.

Summer Electric Rates - June through September; Winter Electric Rates - October through May.

Please note: If your billing period for this statement spans both Summer and Winter seasons, you will see prorated charges that reflect the different rates for each season.

### Rush Island Retirement Cost

Ameren Missouri is acting as the servicer for this Public Service Commission-approved charge for an assignee, who owns the rights to the securitized utility tariff charges related to the Rush Island Energy Center retirement. Based on projections, customers are expected to save about \$85 million over a 15-year period versus standard rates.



### Your Account PIN

Your Account PIN enhances security, verifies your identity, and enables full access to Online Account and Mobile App features. New online or app users will be prompted to enter this PIN once for registration and account validation.

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

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

Seasonal Rate Change - Your electric usage from June 1st through September 30th will be billed at the summer rate which reflects the higher cost of generating electric power in the summer. Look for ways to save energy and money by visiting AmerenMissouri.com/EnergyEfficiency for tips and rebates.

**STRUGGLING TO PAY YOUR BILL?  
HELP IS AVAILABLE.**

Apply to LIHEAP before May 31. See if you qualify at AmerenMissouri.com/Assistance.



**VIEW BILL EARLIER  
SEE BILL HISTORY  
GET REMINDERS VIA TEXT & EMAIL  
ACCESS ANYWHERE**

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# WHEN SEASONS CHANGE, BILLS CAN TOO

When summer temperatures spike, your air conditioning works harder to keep you comfortable.

**This seasonal impact increases your energy use and your bill.**

## ACTIONS YOU CAN TAKE TODAY:

### CONVENIENCE

- Budget Billing
- Pick A Due Date
- Auto Pay
- Online Profile

### CONTROL

- Reverse Fan Direction
- Close Blinds or Drapes
- Seal Air Leaks
- Change HVAC Filter

### CARE

- Payment Agreements
- Energy Assistance
- Grants & Discounts



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[Redacted]

[Redacted]

[Redacted]

**AMOUNT DUE \$693.87**

**Due Date 06/11/2026**

Amount After Due Date \$701.52

Previous Statement \$890.47

Total Payments \$545.00

*Full Payment Not Received*

[Redacted]

[Redacted]

If the prior balance has been paid, pay current amount of \$348.40 only.

**Current Detail for Statement 05/20/2026**

Total Electric Charges	\$339.05
Additional Adjustments (» see details pages)	\$9.35
Prior Balance	\$345.47

**Total Amount Due \$693.87**

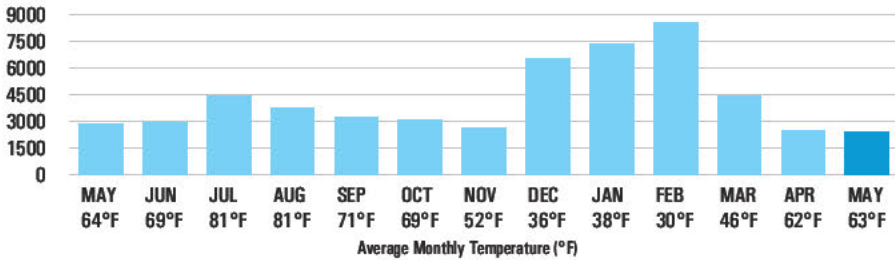
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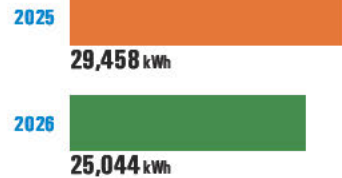
**Electric Usage History**

**Electric Usage in Kilowatt Hours (kWh)**



**Electric Usage Summary (kWh)**

So far this year you're using **15% less** than the same time period last year.



13073 02395 2492768 004784 009567 00010002



» See next page for service details.

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<b>Amount Due</b>	<b>Due Date</b>
\$693.87	June 11, 2026
<b>Delinquent Amount After Due Date</b>	<b>Account Number</b>
\$701.52	[Redacted]

**Amount Enclosed \$** \_\_\_\_\_



>002395 2492768 0001 092139 10Z  
02395 1 AV 0.59 5-D 63111



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**Electric Service Details** Service from 04/19/2026 - 05/18/2026 (29 days)

**Electric Meter Read**

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
██████████	04/19 - 05/18	29	Total kWh	Actual	212555.0000	210159.0000	2396.0000	1.0000	2396.0000

**Usage Summary**

Total kWh	2396.0000	Non-Summer kWh	2396.0000
Winter Base kWh	2829.0000	Current Base kWh	2396.0000
Winter Cur Base kWh	2396.0000	Seasonal kWh	0.0000

**Rate 2M Sm Gen Svc - 1 Ph - No Dmd**



DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Base Energy Charge	2,396.00	kWh	@	\$ 0.10050000	\$240.80
Customer Charge					\$13.72
Fuel Adjustment Charge	2,396.00	kWh	@	\$ 0.00540000	\$12.94
Energy Efficiency Investment Charge	2,396.00	kWh	@	\$ 0.00227200	\$5.44
Renewable Energy Adjustment	2,396.00	kWh	@	\$ 0.00207000	\$4.96
Rush Island Retirement Cost	2,396.00	kWh	@	\$ 0.00118000	\$2.83
<b>Total Service Amount</b>					<b>\$280.69</b>
DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Missouri State Sales Tax	\$280.69		@	\$ 0.04225000	\$11.86
Missouri Local Sales Tax	\$280.69		@	\$ 0.05454000	\$15.31
St. Louis City Municipal Charge - Service	\$280.69		@	\$ 0.11111000	\$31.19
<b>Total Tax Related Charges</b>					<b>\$58.36</b>
<b>Total Electric Charges</b>					<b>\$339.05</b>

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

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**AMOUNT DUE**

**\$693.87**

**Due Date**

**06/11/2026**

**Attachment B**

**Additional Adjustments**

DESCRIPTION	CHARGE
Late Payment Charge on Late Payment	\$0.04
Non-Service Late Payment Charge	\$0.28
Electric Late Payment Charge	\$1.95
Reconnect Charge for Cut-Out Electric Service	\$5.56
Late Payment Charge on Late Payment	\$0.01
Non-Service Late Payment Charge	\$1.26
St. Louis City Municipal Charge - Non Service	\$0.25
<b>Total Additional Adjustments</b>	<b>\$9.35</b>

**Payments Since Previous Statement**

DATE RECEIVED	AMOUNT
May 05, 2026	\$545.00

**Account Messages**

A late payment charge of 1% will be added for any unpaid balance on all accounts after the due date.

Summer Electric Rates - June through September; Winter Electric Rates - October through May.

Please note: If your billing period for this statement spans both Summer and Winter seasons, you will see prorated charges that reflect the different rates for each season.

**Rush Island Retirement Cost**

Ameren Missouri is acting as the servicer for this Public Service Commission-approved charge for an assignee, who owns the rights to the securitized utility tariff charges related to the Rush Island Energy Center retirement. Based on projections, customers are expected to save about \$85 million over a 15-year period versus standard rates.

**Your Account PIN**

Your Account PIN enhances security, verifies your identity, and enables full access to Online Account and Mobile App features. New online or app users will be prompted to enter this PIN once for registration and account validation.

Ameren Missouri's Community Solar program enables your home or small business to support renewable energy in Missouri through an easy monthly subscription. Learn more at [AmerenMissouri.com/CommunitySolar](http://AmerenMissouri.com/CommunitySolar).

Seasonal Rate Change - Your electric usage from June 1st through September 30th will be billed at the summer rate which reflects the higher cost of generating electric power in the summer. Look for ways to save energy and money by visiting [AmerenMissouri.com/EnergyEfficiency](http://AmerenMissouri.com/EnergyEfficiency) for tips and rebates.

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02395 2492768 004785 009569 0002/0002





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[Redacted]

[Redacted]

[Redacted]

**AMOUNT DUE \$6,440.67**

The amount of this bill will be automatically deducted from your bank account 06/18/2026.

**Due Date 06/18/2026**

Amount After Due Date \$6,512.24

Previous Statement \$6,614.57

Total Payments \$6,614.57

*Payment Received. Thank You.*

[Redacted]

[Redacted]

**Current Detail for Statement 05/28/2026**

Total Electric Charges \$6,440.67

**Total Amount Due \$6,440.67**

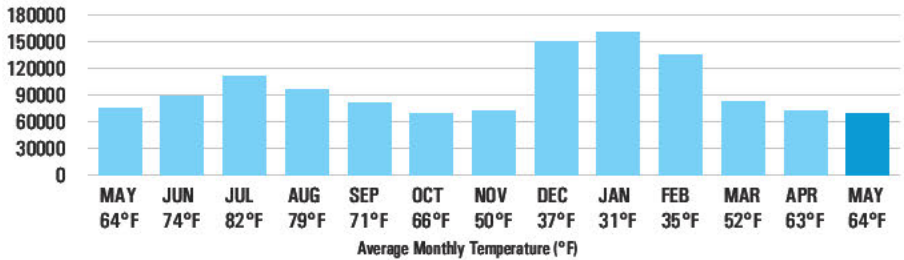
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all year with Budget Billing Rollover.

Manage payments at [AmerenMissouri.com/Budget](http://AmerenMissouri.com/Budget).



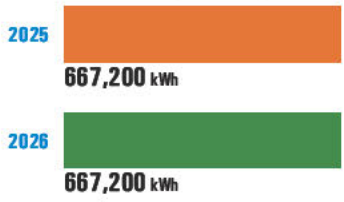
**Electric Usage History**

**Electric Usage in Kilowatt Hours (kWh)**



**Electric Usage Summary (kWh)**

So far this year your electric energy usage is about the same as the same time period last year.



00034 2494774 00065 000129 00010002



» See next page for service details.

Keep this portion for your records.

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Check if you have address changes on back.

<b>Amount Due</b>	<b>Due Date</b>
\$6,440.67	June 18, 2026
<b>Delinquent Amount After Due Date</b>	<b>Account Number</b>
\$6,512.24	[Redacted]

**Amount Enclosed \$** \_\_\_\_\_

>000034 2494774 0001 092139 10Z

[Redacted]

[Redacted]

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**Electric Service Details** Service from 04/26/2026 - 05/26/2026 (30 days)

**Electric Meter Read**

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
██████	04/26 - 05/26	30	Total kWh	Actual	5631.0000	5559.0000	72.0000	960.0000	69120.0000
██████	04/26 - 05/26	30	On Peak kWh	Actual	1999.0000	1973.0000	26.0000	960.0000	24960.0000
██████	04/26 - 05/26	30	Off Peak kW	Actual	0.1680	0.0000	0.1680	960.0000	161.2800
██████	04/26 - 05/26	30	On Peak kW	Actual	0.1500	0.0000	0.1500	960.0000	144.0000

**Usage Summary**





Total kWh	69120.0000	Non-Summer kWh	69120.0000
Peak kW	161.3000	On-Peak kW	144.0000
Off-Peak kW	161.3000	Sec. Energy Block kW	144.0000
Billing Demand	144.0000	Total Billing Demand	144.0000
Winter Billing Demand	144.0000	October Winter Base kW	126.7000
Winter Base Demand	126.7000	Base kWh Ratio	0.8798
Base kWh (HUD)	60812.0000	Seasonal kWh (HUD)	8308.0000

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

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 City, State, Zip \_\_\_\_\_  
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**AMOUNT DUE**

**\$6,440.67**

**Due Date**

**06/18/2026**

**Attachment C**

**Electric Service Details (Continued)**

**Rate 3M Large General Service**

Secondary Srvc Off-Pk Demand Rider

Secondary Srvc Off-Pk Demand Rider

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Seasonal Energy Charge	8,308.00	kWh	@	\$ 0.04530000	\$376.35
Winter Demand Charge	144.00	kW	@	\$ 2.76000000	\$397.44
Base Energy Charge / Hours Used	19,005.00	kWh	@	\$ 0.07740000	\$1,470.99
Base Energy Charge / Hours Used	25,340.00	kWh	@	\$ 0.05750000	\$1,457.05
Base Energy Charge / Hours Used	16,467.00	kWh	@	\$ 0.04530000	\$745.96
Customer Charge					\$122.98
Fuel Adjustment Charge	69,120.00	kWh	@	\$ 0.00540000	\$373.25
Energy Efficiency Investment Charge	69,120.00	kWh	@	\$ 0.00236500	\$163.47
Renewable Energy Adjustment	69,120.00	kWh	@	\$ 0.00207000	\$143.08
Rush Island Retirement Cost	69,120.00	kWh	@	\$ 0.00118000	\$81.56
<b>Total Service Amount</b>					<b>\$5,332.13</b>
DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Missouri State Sales Tax	\$5,332.13		@	\$ 0.04225000	\$225.28
Missouri Local Sales Tax	\$5,332.13		@	\$ 0.05454000	\$290.81
St. Louis City Municipal Charge - Service	\$5,332.13		@	\$ 0.11111000	\$592.45
<b>Total Tax Related Charges</b>					<b>\$1,108.54</b>
<b>Total Electric Charges</b>					<b>\$6,440.67</b>

00034 2494774 000066 000131 00020002

**Payments Since Previous Statement**

DATE RECEIVED	AMOUNT
May 19, 2026	\$6,614.57

**Account Messages**

A late payment charge of 1% will be added for any unpaid balance on all accounts after the due date.

Summer Electric Rates - June through September; Winter Electric Rates - October through May.

Please note: If your billing period for this statement spans both Summer and Winter seasons, you will see prorated charges that reflect the different rates for each season.

**Rush Island Retirement Cost**

Ameren Missouri is acting as the servicer for this Public Service Commission-approved charge for an assignee, who owns the rights to the securitized utility tariff charges related to the Rush Island Energy Center retirement. Based on projections, customers are expected to save about \$85 million over a 15-year period versus standard rates.

**Your Account PIN**

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# WHEN SEASONS CHANGE, BILLS CAN TOO

When summer temperatures spike, your air conditioning works harder to keep you comfortable.

**This seasonal impact increases your energy use and your bill.**

## ACTIONS YOU CAN TAKE TODAY:

### CONVENIENCE

- Budget Billing
- Pick A Due Date
- Auto Pay
- Online Profile

### CONTROL

- Reverse Fan Direction
- Close Blinds or Drapes
- Seal Air Leaks
- Change HVAC Filter

### CARE

- Payment Agreements
- Energy Assistance
- Grants & Discounts

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[Ameren.com/SeasonalRelief](http://Ameren.com/SeasonalRelief)



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[Redacted]

[Redacted]

[Redacted]

**AMOUNT DUE \$25,334.20**

**Due Date 05/27/2026**

Amount After Due Date \$25,587.54

Previous Statement \$23,377.87

Total Payments \$23,377.87

Payment Received. Thank You.

[Redacted]

[Redacted]

**Current Detail for Statement 05/05/2026**

Total Electric Charges \$25,334.20

**Total Amount Due \$25,334.20**

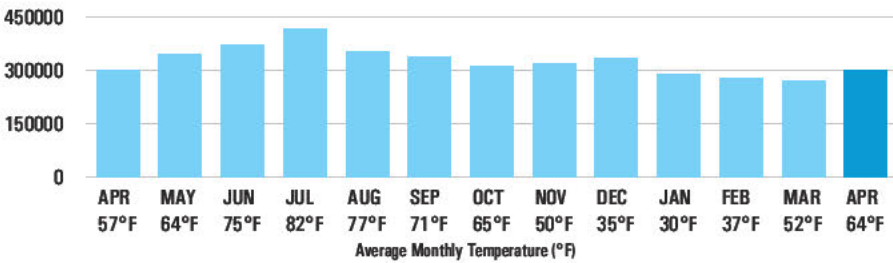
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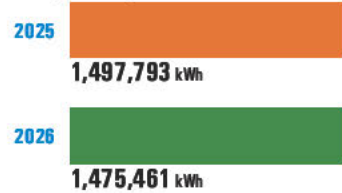
**Electric Usage History**

**Electric Usage in Kilowatt Hours (kWh)**



**Electric Usage Summary (kWh)**

So far this year you're using **1.5% less** than the same time period last year.




13073 01631 2488365 003256 006511 00010002

**REACHING YOU IN CRITICAL MOMENTS MATTER**

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» See next page for service details.

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<b>Amount Due</b>	<b>Due Date</b>
\$25,334.20	May 27, 2026
<b>Delinquent Amount After Due Date</b>	<b>Account Number</b>
\$25,587.54	[Redacted]

**Amount Enclosed \$** \_\_\_\_\_

>001631 2488365 0005 092139 10Z

[Redacted]

[Redacted]

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**Electric Service Details** Service from 03/28/2026 - 04/28/2026 (31 days)

**Electric Meter Read**

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
██████	03/28 - 04/28	31	Total kWh	Actual	300997.0000	0.0000	300997.0000	1.0000	300997.0000
██████	03/28 - 04/28	31	Peak kW	Actual	538.8800	0.0000	538.8800	1.0000	538.8800
██████	03/28 - 04/28	31	On Peak kWh	Actual	107962.0000	0.0000	107962.0000	1.0000	107962.0000
██████	03/28 - 04/28	31	Off Peak kWh	Actual	193035.0000	0.0000	193035.0000	1.0000	193035.0000
██████	03/28 - 04/28	31	Off Peak kW	Actual	517.1200	0.0000	517.1200	1.0000	517.1200
██████	03/28 - 04/28	31	Total KVARH	Actual	185417.0000	0.0000	185417.0000	1.0000	185417.0000
██████	03/28 - 04/28	31	On Peak kW	Actual	538.8800	0.0000	538.8800	1.0000	538.8800

**Usage Summary**

Total kWh	300997.0000	Non-Summer kWh	300997.0000
Peak kW	538.9000	On-Peak kW	538.9000
Off-Peak kW	517.1000	Total KVARH	185417.0000
Sec. Energy Block kW	538.9000	Reactive KVAR	71.0000
Total Billing Demand	538.9000	Winter Billing Demand	538.9000
Billing Demand	538.9000	October Winter Base kW	545.3000
Winter Base Demand	538.9000	Base kWh Ratio	1.0000
Base kWh (HUD)	300997.0000	Seasonal kWh (HUD)	0.0000

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

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**AMOUNT DUE**

**\$25,334.20**

**Due Date**

**05/27/2026**

**Attachment D**

**Electric Service Details (Continued)**

**Rate 4M Small Primary Electric Service**

Energy Efficiency Investment Opt Out

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Winter Demand Charge	538.90	kW	@	\$ 2.33000000	\$1,255.64
Base Energy Charge / Hours Used	80,835.00	kWh	@	\$ 0.07550000	\$6,103.04
Base Energy Charge / Hours Used	107,780.00	kWh	@	\$ 0.05620000	\$6,057.24
Base Energy Charge / Hours Used	112,382.00	kWh	@	\$ 0.04390000	\$4,933.57
Reactive Charge	71.00	KVAR	@	\$ 0.44810000	\$31.82
Customer Charge					\$415.41
Fuel Adjustment Charge	300,997.00	kWh	@	\$ 0.00523000	\$1,574.21
Energy Efficiency Investment Charge	300,997.00	kWh	@	\$ 0.00000000	\$0.00
Renewable Energy Adjustment	300,997.00	kWh	@	\$ 0.00207000	\$623.06
Rush Island Retirement Cost	300,997.00	kWh	@	\$ 0.00113934	\$342.94
<b>Total Service Amount</b>					<b>\$21,336.93</b>
DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Missouri State Sales Tax	\$21,336.93		@	\$ 0.04225000	\$901.49
Missouri Local Sales Tax	\$21,336.93		@	\$ 0.04763000	\$1,016.28
Warson Woods Municipal Charge - Service	\$21,336.93		@	\$ 0.09746000	\$2,079.50
<b>Total Tax Related Charges</b>					<b>\$3,997.27</b>
<b>Total Electric Charges</b>					<b>\$25,334.20</b>

01631 2488365 003257 006513 0002/0002

**Payments Since Previous Statement**

DATE RECEIVED	AMOUNT	DATE RECEIVED	AMOUNT
April 13, 2026	\$13,377.87	April 20, 2026	\$2,500.00
April 20, 2026	\$2,500.00	April 20, 2026	\$2,500.00
April 20, 2026	\$2,500.00		

**Account Messages**

A late payment charge of 1% will be added for any unpaid balance on all accounts after the due date.

Summer Electric Rates - June through September; Winter Electric Rates - October through May.

Please note: If your billing period for this statement spans both Summer and Winter seasons, you will see prorated charges that reflect the different rates for each season.

**Rush Island Retirement Cost**

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Seasonal Rate Change - Your electric usage from June 1st through September 30th will be billed at the summer rate which reflects the higher cost of generating electric power in the summer. Look for ways to save energy and money by visiting [AmerenMissouri.com/EnergyEfficiency](http://AmerenMissouri.com/EnergyEfficiency) for tips and rebates.

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**AMOUNT DUE \$137,520.46**

**Due Date 06/01/2026**

**Current Detail for Statement 05/08/2026**

Total Electric Charges \$137,520.46

Amount After Due Date \$138,895.66

**Total Amount Due \$137,520.46**

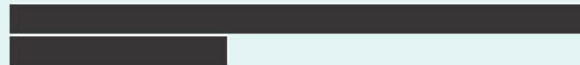
Previous Statement \$155,983.42

Total Payments \$155,983.42

*Payment Received. Thank You.*

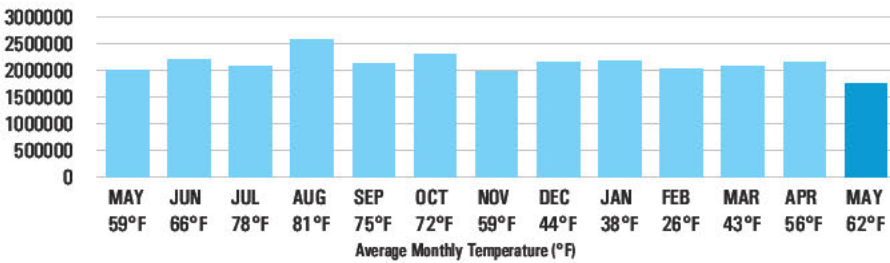
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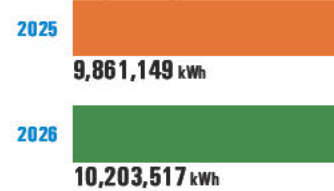
**Electric Usage History**

**Electric Usage in Kilowatt Hours (kWh)**



**Electric Usage Summary (kWh)**

So far this year you're using **3.5% more** than the same time period last year.





13073 04841 2489516 0008 092139 102

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» See next page for service details.

Keep this portion for your records.



Check if you have address changes on back.

Please return this portion with your payment.

Amount Due	Due Date
\$137,520.46	June 01, 2026
Delinquent Amount After Due Date	Account Number
\$138,895.66	[Redacted]

Amount Enclosed \$ \_\_\_\_\_

>004841 2489516 0008 092139 102



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**Electric Service Details** Service from 04/04/2026 - 05/05/2026 (31 days)

**Electric Meter Read**

METER NUMBER	SERVICE FROM - TO	NO. DAYS	USAGE TYPE	READING TYPE	CURRENT READING	PREVIOUS READING	READING DIFFERENCE	MULTIPLIER	USAGE
██████	04/04 - 05/05	31	Total kWh	Actual	909511.0000	0.0000	909511.0000	1.0000	909511.0000
██████	04/04 - 05/05	31	Total kWh	Actual	850566.0000	0.0000	850566.0000	1.0000	850566.0000
██████	04/04 - 05/05	31	On Peak kWh	Actual	332389.0000	0.0000	332389.0000	1.0000	332389.0000
██████	04/04 - 05/05	31	On Peak kWh	Actual	319601.0000	0.0000	319601.0000	1.0000	319601.0000
██████	04/04 - 05/05	31	Off Peak kWh	Actual	577122.0000	0.0000	577122.0000	1.0000	577122.0000
██████	04/04 - 05/05	31	Off Peak kWh	Actual	530965.0000	0.0000	530965.0000	1.0000	530965.0000
██████	04/04 - 05/05	31	Off Peak kW	Actual	1793.2800	0.0000	1793.2800	1.0000	1793.2800
██████	04/04 - 05/05	31	Off Peak kW	Actual	1561.9200	0.0000	1561.9200	1.0000	1561.9200
██████	04/04 - 05/05	31	Total KVARH	Actual	359161.0000	0.0000	359161.0000	1.0000	359161.0000
██████	04/04 - 05/05	31	Total KVARH	Actual	537945.0000	0.0000	537945.0000	1.0000	537945.0000
██████	04/04 - 05/05	31	On Peak kW	Actual	1658.8800	0.0000	1658.8800	1.0000	1658.8800
██████	04/04 - 05/05	31	On Peak kW	Actual	1637.7600	0.0000	1637.7600	1.0000	1637.7600

**Usage Summary**



Total kWh	1760077.0000	Non-Summer kWh	1760077.0000
On-Peak kW	3296.6000	Off-Peak kW	3355.2000
Total KVARH	897106.0000	Sec. Energy Block kW	3296.6000
Reactive KVAR	83.7000	Total Billing Demand	5000.0000
Winter Billing Demand	5000.0000		

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

**Address Changes or Corrections**

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 City, State, Zip \_\_\_\_\_  
 Phone Number \_\_\_\_\_

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**AMOUNT DUE****\$137,520.46****Due Date****06/01/2026****Attachment E****Electric Service Details (Continued)****Rate 11M Lg Primary Electric Service**

DESCRIPTION	USAGE	UNIT		RATE	CHARGE
Winter Total Energy Charge	1,760,077.00	kWh	@	\$ 0.03710000	\$65,298.86
Winter Demand Charge	5,000.00	kW	@	\$ 10.63000000	\$53,150.00
Reactive Charge	83.70	KVAR	@	\$ 0.44810000	\$37.51
Customer Charge					\$704.65
Fuel Adjustment Charge	1,760,077.00	kWh	@	\$ 0.00523000	\$9,205.20
Energy Efficiency Investment Charge	1,760,077.00	kWh	@	\$ 0.00196400	\$3,456.79
Renewable Energy Adjustment	1,760,077.00	kWh	@	\$ 0.00207000	\$3,643.36
Rush Island Retirement Cost	1,760,077.00	kWh	@	\$ 0.00115000	\$2,024.09
<b>Total Service Amount</b>					<b>\$137,520.46</b>
<b>Total Electric Charges</b>					<b>\$137,520.46</b>

**Payments Since Previous Statement**

DATE RECEIVED	AMOUNT
April 29, 2026	\$155,983.42

**Account Messages**

A late payment charge of 1% will be added for any unpaid balance on all accounts after the due date.

Summer Electric Rates - June through September; Winter Electric Rates - October through May.

Please note: If your billing period for this statement spans both Summer and Winter seasons, you will see prorated charges that reflect the different rates for each season.

**Rush Island Retirement Cost**

Ameren Missouri is acting as the servicer for this Public Service Commission-approved charge for an assignee, who owns the rights to the securitized utility tariff charges related to the Rush Island Energy Center retirement. Based on projections, customers are expected to save about \$85 million over a 15-year period versus standard rates.

**Your Account PIN**

Your Account PIN enhances security, verifies your identity, and enables full access to Online Account and Mobile App features. New online or app users will be prompted to enter this PIN once for registration and account validation.

Seasonal Rate Change - Your electric usage from June 1st through September 30th will be billed at the summer rate which reflects the higher cost of generating electric power in the summer. Look for ways to save energy and money by visiting [AmerenMissouri.com/EnergyEfficiency](http://AmerenMissouri.com/EnergyEfficiency) for tips and rebates.

**Auto Pay Makes Paying Bills Easier.** To enroll, go to [AmerenMissouri.com](http://AmerenMissouri.com) or call 1.800.552.7583 to request an enrollment form.

04841 2489516 009682 019363 0002/0002





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

INCLUSIONS:

FAC Subparagraph #	Account	Subaccount/Resource Type	Compliance Code	Description
1 A:	501			FERC Account 501 contains costs/revenues associated with the fuel used in the production of steam for the generation of electricity.
		001 / FB or FI		Costs/revenues for coal used by the coal fired units to generate electricity, such as: - coal commodity costs. - adjustments related to British Thermal Unit (BTU) and Sulfur Dioxide (SO2) quality for each shipment of coal actually received vs. what was contracted to be received. - hedging costs/revenues resulting from forward purchase contracts used to hedge coal purchase costs. - revenues and expenses resulting from fuel portfolio optimization activities which historically have consisted of coal commodity sales. - semi-annual inventory adjustments determined by use of an independent 3rd party to measure each coal pile to true-up the coal burn amounts.
		110 / FB or FI		Transportation costs/revenues associated with coal used by the coal fired units to generate electricity, such as: - railroad, truck and barge transportation costs. - diesel surcharges for railroad transportation. - railcar repair and inspection costs. - railcar depreciation, railcar leases. - hedging costs/revenues resulting from forward purchase rail contracts and financial instruments to hedge diesel surcharges. - rail switching charges and demurrage charges associated with rail, truck, and barge transportation. - revenues and expenses resulting from transportation portfolio optimization activities which historically have consisted of railcar lease termination fees to allow for lower cost leases - semi-annual inventory adjustments determined by use of an independent 3rd party to measure utilizing a global positioning system ("GPS") survey of each coal pile to true-up the coal burn amounts.
		002 / FB 012 / FI		Costs/revenues for startup oil used by the coal fired units to generate electricity such as oil commodity costs, truck transportation costs, and fuel portfolio optimization activities which historically have consisted of oil commodity sales.
		003 / FB 013 / FI		Cost/revenues associated with the gas used by the coal fired and natural gas fired units to generate electricity, such as: - gas commodity costs. - pipeline transportation and storage costs. - hedging costs/revenues resulting from forward purchase pipeline transportation contracts. - hedging costs/revenues resulting from forward purchase contracts, call options, and financial instruments used to hedge gas purchases.
		008 / ≠ LC, LI, LM, LR, LU 018 / ≠ LC, LI, LM, LR, LU		Costs/revenues associated with coal ash disposal such as: - physical disposal costs. - trucking services. - coal ash sales.
B:	502			FERC Account 502 contains cost/revenues associated with the fuel additives used as part of air quality control operations for coal fired generation.
		002		Cost of powder activated carbon (including truck transportation costs) used as part of air quality control operations at the coal fired plants.
		003		Cost of limestone (including truck transportation costs) used as part of air quality control operations at the coal fired plants.
		007		Cost of Urea (including truck transportation costs) used as part of air quality control operations at the coal fired plants.
C:	547			FERC Account 547 contains costs/revenues associated with the fuel used in other power generation, including Combustion Turbine Generator (CTG) units.
		002 / FB 012 / FI		Costs/revenues for oil used in other power generation, which includes both natural gas fired and oil-fired CTGs to generate electricity, including oil commodity costs, truck transportation costs, and fuel portfolio optimization activities which have historically consisted of oil commodity sales.
		003 / FB 013 / FI		Costs/revenues of gas used in other power generation, which includes CTGs to generate electricity, such as: - gas commodity costs. - pipeline transportation, storage and capacity reserve costs. - fuel losses. - hedging costs/revenues associated with pipeline transportation contracts. - hedging costs/revenues associated with gas purchases. - revenues and expenses resulting from transportation portfolio optimization activities such as pipeline capacity releases and gas commodity sales.
2	518			FERC Account 518 contains cost/revenues associated with the use of nuclear fuel used to generate electricity.
		002		Cost/revenues associated with nuclear fuel used to generate electricity such as: - Nuclear fuel costs (including conversion, enrichment, and fabrication, including safety evaluations and fuel assembly engineering evaluation and analysis, which are necessary to produce the fuel assemblies that are loaded into the reactor.) Monthly nuclear fuel costs recorded to the general ledger as fuel expense reflect an amortization of the total cost of the fuel assemblies to reflect consumption of fuel rods as the plant operates. - storage costs. - hedging costs/revenues associated with nuclear fuel purchases.
		005		Costs associated with the disposal of nuclear fuel waste.

EXCLUSIONS:

FAC Subparagraph #	Account	Subaccount/Resource Type	Compliance Code	Description		
	501			Costs/revenues associated with coal handling, labor, and materials and supplies inventory.		
		000				
		001 NOT FB or FI				
		005				
		020				
		030				
		502	000			Costs/revenues associated with steam operations.
		502	010			Costs/revenues associated with mercury control chemicals.
		547	004			Costs/revenues associated with landfill gas commodity.

Notes: Resource Type ("RT") = FB is utilized for managerial reporting and identifies the allocation of fuel costs related to the Company's native load, which are sales to MPSC tariffed customers.  
 Resource Type ("RT") = FI is utilized for managerial reporting and identifies the allocation of fuel costs related to the Company's remaining sales.  
 Compliance Code ("CP") is not used to distinguish costs for inclusion in the FAC for FERC accounts 501, 518 or 547.

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

INCLUSIONS:

FAC Subparagraph #	Account	Subaccount	Compliance Code*	Description
1 A: i:	555	MIS		FERC Account-555 contains costs directly related to Purchased Power Subaccount: MIS All MISO costs associated with the below listed items:
			PPBLD	Net energy purchases allocated to native-load sales. Net energy purchases are the netted dollars for sales/purchases made each hour to the RTO settlements, resulting from Ameren Missouri's application of FERC Order 608/608A to the RTO settlements. This is done separately for the DA and RT markets. For managerial reporting purposes, these net energy purchases are then further allocated between interchange sales (PPISD) and native-load sales (PPBLD). MISO looks at the generation and load for each hour and bills the net amount.
			PPISD	Net energy purchases allocated to all sales other than native-load sales. Net energy purchases are the netted dollars for sales/purchases made each hour to the RTO settlements, resulting from Ameren Missouri's application of FERC Order 608/608A to the RTO settlements. This is done separately for the DA and RT markets. For managerial reporting purposes, these net energy purchases are then further allocated between interchange sales (PPISD) and native-load sales (PPBLD). MISO looks at the generation and load for each hour and bills the net amount.
			MSSRD	Costs and revenues associated with generation units designated as System Support Resources (SSR) by an RTO.
ii:			MLOS0	The component of the location marginal price (LMP) associated with energy losses. LMP is a price for Energy at a specified location in the transmission regions and is comprised of three components: Marginal Energy, Marginal Losses and Marginal Congestion.
iii: a.			MCNG0	The component of the locational marginal price (LMP) associated with implicit system congestion. LMP is a price for Energy at a specified location in the transmission regions and is comprised of three components: Marginal Energy, Marginal Losses and Marginal Congestion.
b.		MIS or PRY	MFTR0	Net costs associated with financial transmission rights (FTRs). Net settlement for FTR's, including the initial acquisition cost and periodic settlements. FTRs are a financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges that arise when the Transmission System is congested and differences in Marginal Congestion Components of Day-Ahead LMPs between two specific locations such as a generator and a load.
c.		MIS	MARR0	Net costs associated with auction revenue rights (ARRs). ARRs are entitlements to a share of the revenues generated in the annual FTR Auction.
iv:			DCBLD	Capacity purchased for native-load for contracts under 1 year. This capacity purchase may be through a bilateral contract with another party or in an RTO capacity market.
v:			MRS00	Revenue Sufficiency Guarantee. Allocation of costs to load serving entities arising from credits provided to resources committed and scheduled by MISO to ensure minimum recovery of production and operating reserve costs. This allows for recovery of "as offered" price of generation called on for reliability purposes. An "as offered" price typically includes an estimation of startup costs and costs incurred even if the generation does not provide energy. It could be a cost or a reduction to a previously assigned cost.
vi:			MRNU0	Revenue Neutrality Uplift Charge. Revenue Neutrality Uplift is the mechanism through which MISO refunds excess revenues collected to Market Participants or collects revenue deficiencies from Market Participants.
			SC400	Available System Capacity Cost Allocation Charge. Activity associated with energy market charges arising under MISO Schedule 40, which are payments required to the Southwest Power Pool (SPP) for impacts of MISO's energy markets on SPP.
vii:			MIDV0	Net Inadvertent Distribution. Allocation of costs and revenues to load arising from MISO's resolution of net inadvertent energy. Inadvertent energy is the difference between MISO's scheduled and actual interchange with other balancing authorities.
viii:			MSTR0	Ancillary Services - The Short-Term Reserve ancillary service product provides reserved and rampable capacity and compensates the online and offline generation resources that can produce energy within a 30-minute response time.
a.			RFRS0	Regulating Reserve charge is for capacity held in reserve by MISO as a frequency responsive resource, for the purpose of automatically and continuously adjusting its output to maintain the supply/demand balance in the MISO balancing authority area in accordance with applicable reliability standards. RFRS revenue for the Company's capacity reserved as a frequency responsive resource is recorded in account 447.
b.			PPISD	Energy purchased for net sales other than native-load related to the energy imbalance (between RT and DA) charges. MISO accounts for energy imbalance through the operation of the Real-Time Energy Market, which charges are included in the net energy amount reported in 1(A)(i) above.
			PPBLD	Energy purchased for net native load sales related to the energy imbalance (between RT and DA) charges. MISO accounts for energy imbalance through the operation of the Real-Time Energy Market, which charges are included in the net energy amount reported in 1(A)(i) above.
c.			SPRS0	Ancillary Services - Spinning Reserve - Schedule 5 charges. Spinning Reserve charge is for the portion of an operating resource capability which is held back (reserved) and able to be converted to energy within ten minutes of being instructed to deploy by MISO. SPRS revenue for the Company's resources offered as spinning reserve is recorded in account 447.
d.			SURS0	Ancillary Services - Supplemental Reserve - Schedule 6 charges. Supplemental Reserve charge is for non-synchronized (off-line) resources which can be converted to energy within ten minutes of being instructed to deploy by MISO. SURS revenue for the Company's resources offered as ancillary services resources are recorded in account 447.
ix: a.			DRAU0	A MISO charge for Real Time Demand Response Allocation Uplift. This is a charge type used to collect Demand Response Compensation when the LMP Demand Response Resource exceeds the Net Benefits Price Threshold.

b.			SC300	Schedule 30 Emergency demand response. Allocation by MISO of charges related to the commitment and dispatch of interruptible demand, behind-the-meter generation and other demand resources that are capable of helping meet the energy balance during NERC Energy Emergency.
B: i:				Subaccount: PJM Interconnection and/or SPP (Southern Power Pool) - Regional Transmission Operators
		PJM and SPP	PPIS0	Net energy purchases allocated to net sales other than native-load
		PJM and SPP	PPBL0	Net energy purchased for native-load.
		PJM	PLOS0	The component of locational marginal price (LMP) associated with energy losses.
		PJM	PCNG0	The component of the locational marginal price (LMP) associated with implicit system congestion.
		PJM	PRSG0	Balancing Operating Reserve – Equivalent to Revenue Sufficiency Guarantee in MISO
		PJM	PFTR0	Net costs associated with FTRs and ARRs
		PJM	FIDVD	Net Inadvertent Distribution - Allocation of costs and revenues to load arising from the RTO's resolution of net inadvertent energy. Inadvertent energy is the difference between PJM/SPP's scheduled and actual interchange with other balancing authorities.
		SPP	DRAU0	Net charge required in order to remove the settlement impact of grossing up the host load by the amount of associated Demand Response Resource output and/or in which a Demand Response Resource was cleared in order to fund the credits paid for Demand Response Reduction (corresponding to MISO demand response).
		SPP	MARR0	Net costs associated with auction revenue rights (ARRs). ARRs are entitlements to a share of the revenues generated in the annual and monthly Transmission Congestion Rights auctions (corresponding to MISO ARRs).
		SPP	MFTR0	Net costs associated with Transmission Congestion Rights (TCRs). Net settlement for TCR's, including the initial acquisition cost and periodic settlements. (corresponding to MISO FTRs)
		SPP	MLOS0	The component of locational marginal price (LMP) associated with energy losses (corresponding to MISO losses).
		SPP	MCNG0	The component of the locational marginal price (LMP) associated with implicit system congestion (corresponding to MISO congestion).
		SPP	MMSG0	Reliability Unit Commitment Make Whole Payment (corresponding to Revenue Sufficiency Guarantee in MISO).
		SPP	MRNU0	Revenue Neutrality Uplift Charge. (corresponding to MISO RNU).
		PJM and SPP	RFRS0	Ancillary services - Charges for Reserve and Regulation services (corresponding to MISO Regulating Reserve).
		PJM and SPP	SPRS0	Ancillary services - Charges for Spinning Reserve (corresponding to MISO Spinning Reserve).
	PJM and SPP	SURS0	Ancillary services - Charges for Supplemental Reserve (corresponding to MISO Supplemental Reserve).	
i: a.		All subaccounts excluding MIS, PJM or SPP		Subaccount: Used to primarily distinguish counterparties for managerial reporting All non-MISO, PJM and SPP costs associated with the below listed items/compliance codes:
b.			PPBL0	Net energy purchases allocated to native-load sales
			PPIS0	Net energy purchases allocated to all sales other than native-load
			DCIS0	Purchased capacity allocated to net sales other than native-load with a duration of one year or less.
c:			DCBL0	Purchased capacity allocated to native-load sales with a duration of one year or less.
		XXX		Realized losses and costs (including broker commissions and fees) for financial swap transactions to mitigate volatility.

EXCLUSIONS:

FAC Subparagraph #	Account	Subaccount	Compliance Code	Description
	555	MIS		Costs associated with MISO schedules that are specifically excluded from the FAC.
			SC240	Control area recovery
			SC340	Penalty Assessment
			MDEV0	RTO uninstruced deviation
			PSIM0	Product & Svc implementation
		SPP	SC1A0	Administrative fees
		All subaccounts	REEA0	Renewable energy/energy assistance

Notes:

DA means the Day-Ahead energy market.  
 RT means the actual delivered energy (Real Time)  
 Net off-system sales, interchange sale and net sales other than native load are the same thing.  
 To the extent any amounts in the accounts above relate to RES-compliance, these amounts will be excluded from the FAC and included in the RESRAM.  
 \* Compliance Codes are same values as former Activity Codes with a zero added to the end (5 digits vs 4).

Ameren Missouri  
Account Descriptions  
Report 5(i)  
April 2026

For PP = Purchased power costs and revenues in FERC accounts 565 and 456.1:

INCLUSIONS:

FAC Subparagraph #	Account	Subaccount	Compliance Code <sup>a</sup>	Description
2 A:	565	MIS		FERC Account 565 contains costs related to the Transmission of Electricity by Others. Subaccount MIS All MISO costs associated with the following items.
i:			TRUND	Purchase of unbundled transmission (Schedule 9 - Network Integration Transmission Service (NITS)) Electric service is traditionally provided by bundling the generation, transmission, and distribution services. Through unbundling, the services can be separated which results in separate pricing and different suppliers or sources for each of the components. NITS represents the transmission service portion, these are covered by our long-term reservation. Ameren Missouri has three MISO NITS reservations - one for its native load in the AMMO pricing zone; one for its native load in the Entergy Arkansas pricing zone and a separate reservation to serve the City of Perry. Ameren Missouri's designated resources (Ameren Missouri's generation portfolio) is designated to serve these zones.
ii:			SC070	RTO amounts for Schedule 7 - Firm Point to Point Transmission Service Point to Point service uses the transmission system to transmit energy from one point to another. Point to Point can be Firm (service can NOT be interrupted) or Non-Firm (service can be interrupted). This is typically associated with bilateral contracts.
			SC080	RTO amounts for Schedule 8 - Non-Firm Point to Point Transmission Service Point to Point service uses the transmission system to transmit energy from one point to another. Point to Point can be Firm (service can NOT be interrupted) or Non-Firm (service can be interrupted). This is typically associated with bilateral contracts.
iii:			SC010	RTO amounts for Schedule 1 - Scheduling System Control & Dispatch Scheduling and administering the movement of power into, out of, through, or within the MISO Balancing Authority.
iv:			SC020	RTO amounts for Schedule 2 - Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.
v:			SC260	RTO amounts for Schedule 26 - Network Upgrades Transmission Expansion Transmission charge for Network Upgrade Charge from Transmission Expansion Plan under the Regional Expansion Criteria and Benefits (RECB) provisions of the Tariff which is composed of Attachment FF, Attachment GG and Schedule 26. MISO Attachment GG prescribes the revenue requirement calculation for Schedule 26 charges. Historically, the MISO Tariff has included the following types of projects eligible for regional allocation under Attachment GG: > Market Efficiency Projects > Generator Interconnections if they are 345kV > Certain reliability projects approved before 2013 (such as the Company's Lutesville-Heritage line) Cost allocation to pricing zones is performed when project approved based upon project type and voltage. > Market Efficiency - 20% allocated MISO-wide based on load - 80% allocated to Local Resource Zone based on benefits > Reliability projects approved prior to 2013 Tariff change - 345kv facilities - 20% allocated MISO-wide based on load - Remaining facilities allocated sub-regionally based on LODF (Line Outage Distribution Factor) > Generator Interconnections - Per terms of MISO Attachment X - Generally paid by generator
			S26AD	RTO amounts for Schedule 26A - Multi Value Projects MVP is a transmission planning and cost allocation project category for projects that qualify based on multiple reliability and/or economic criteria affecting multiple transmission zones. MISO Attachment MM prescribes revenues to be collected under Schedule 26-A. Schedule 26A specifically involves a portfolio of Multi-Value Projects (MVPs) across MISO approved by the MISO Board in December 2011, whereas Schedule 26 is more regional in nature. • Must meet at least one of the following Criteria to be an MVP > Developed through MISO planning process and support energy policy > Provide multiple types of economic value across multiple pricing zones with benefit to cost ratio > 1 > Address at least one: - Projected NERC violation - Economic-based issue • MISO-wide allocation across MISO based on load > Attachment MM format is very similar to Attachment GG > Energy market settlement > Currently MISO North load until end of transition period and then 8 year phase-in for MISO South AMMO Zone was approximately 7.5% of MISO North load in 2014
			S26C0	RTO Amounts for Schedule 26-C: Cost Recovery for Targeted Market Efficiency Projects (TMEP) Constructed by MISO Transmission Owners Transmission charge that provides the mechanism for recovery of the revenue requirements for TMEPs constructed by MISO Transmission Owners. The TMEPs are an interregional transmission project type between MISO and PJM intended to reduce historical congestion along the border between MISO and PJM to benefit customers and improve coordination between the two RTOs.
			S26D0	RTO Amounts for Schedule 26-D: Cost Recovery for Targeted Market Efficiency Projects (TMEP) Constructed by PJM Interconnection, LLC Transmission Owners Transmission charge that provides the mechanism for recovery of the revenue requirements for TMEPs constructed by PJM Transmission Owners. The TMEPs are an interregional transmission project type between MISO and PJM intended to reduce historical congestion along the border between MISO and PJM to benefit customers and improve coordination between the two RTOs.

# Attachment F

			S28E0	RTO Amounts for Schedule 26-E: Cost Recovery for Interregional Market Efficiency Projects (IMEP) Constructed by MISO Transmission Owners Transmission charge that provides the mechanism for recovery of the revenue requirements for IMEPs constructed by MISO Transmission Owners. The IMEPs are an interregional transmission project type between MISO and PJM intended to reduce historical congestion along the border between MISO and PJM to benefit customers and improve coordination between the two RTOs.
			S28F0	RTO Amounts for Schedule 26-F: Cost Recovery for Interregional Market Efficiency Projects (IMEP) Constructed by PJM Interconnection, LLC Transmission Owners Transmission charge that provides the mechanism for recovery of the revenue requirements for IMEPs constructed by PJM Transmission Owners. The IMEPs are an interregional transmission project type between MISO and PJM intended to reduce historical congestion along the border between MISO and PJM to benefit customers and improve coordination between the two RTOs.
			SC370	RTO amounts for Schedule 37 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for American Transmission System, Inc. (ATSI) Zone Transmission charge that provides the mechanism for recovering a portion of the MTEP Projects constructed or approved by the MISO Board of Directors (approved prior to ATSI exit from MISO) for construction by ATSI upon ATSI's integration into PJM.
			SC380	RTO amounts for Schedule 38 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for Duke Energy Ohio (DEO) and Duke Kentucky (DEK) Transmission charge that provides the mechanism for recovering a portion of the MTEP Projects constructed or approved by the MISO Board of Directors (approved prior to DEO/DEK exit from MISO) for construction by DEO/DEK upon DEO/DEK's integration into PJM.
vi:			SC330	RTO amounts for Schedule 33 - Black Start Service Charge to facilitate reliable and complete system restoration following a shut down of the bulk power Transmission System. Blackstart Service enables Transmission Operators to designate specific generation facilities as Blackstart Units whose location and capabilities are required to assist in re-energizing a specific portion of the Transmission System following a system-wide blackout.
vii:			SC410	Charge to Recover Costs of Entergy Storm Securitization Charges from Entergy Operating Companies' Pricing Zones MISO mechanism for collecting storm securitization charges from reservations sinking in Entergy. These transmission charges possess the characteristic of, and are of the nature of, the transmission charges assessed to Ameren Missouri by Entergy to serve Ameren Missouri load using Entergy transmission prior to Entergy joining MISO.
			S42A0	Charge to Recover Accrued and Paid Interest Associated with Prepayments From Entergy Operating Companies' Pricing Zones MISO mechanism for collecting accrued and paid interest associated with prepayments for network upgrades to the Entergy Operating Companies. These transmission charges possess the characteristic of, and are of the nature of, the transmission charges assessed to Ameren Missouri by Entergy to serve Ameren Missouri load using Entergy transmission prior to Entergy joining MISO.
			S42B0	Credit Associated with AFUDC From Entergy Operating Companies' Pricing Zones MISO mechanism for collecting AFUDC credits from network upgrades to the Entergy Operating Companies. These transmission charges possess the characteristic of, and are of the nature of, the transmission charges assessed to Ameren Missouri by Entergy to serve Ameren Missouri load using Entergy transmission prior to Entergy joining MISO.
			SC450	Cost Recovery of NERC Recommendations or Essential Action Transmission charge that provides a mechanism for Transmission Owners who are Registered Entities registered under the NERC Functional Model to recover costs for NERC Recommendations or Essential Action projects eligible under Attachment FF, Attachment GG and Schedule 45.
			SC470	Entergy Operating Companies MISO Transition Cost Recovery MISO mechanism for recovery of the deferred operation and maintenance costs and accrued carrying charges accumulated by the Entergy Operating Companies related to their integration into MISO.
B:	565	All others		Subaccount: Used to distinguish Non-MISO counterparty transactions for FERC Form reporting (ex: 565PJM and 565SFP)
			SC110	SPP Schedule 11 Base Plan Zonal and Reginal Charge - Costs of facilities whose costs are shared in whole or in part on a regional postage stamp basis. The remainder of the costs of these facilities is allocated to the zone in which each facility is located. (Corresponds to MISO Schedules 28 and 28-)
			IFAC0	Expenses arising from agreements authorized under Generator Interconnection Agreements (GIA) procedures under the MISO tariff.
i & ii:			TRUN0	Purchase of unbundled transmission (Network Transmission Service) - see definition above. This includes both NITS and point-to-point transmission charges in RTO's other than MISO.
			PITR0	PJM transmission charges related to Network Integration Transmission Service, Transmission Enhancement, Non-Firm Point-to-Point Transmission Service, Black Start Service and Expansion Cost Recovery.
			SC080	Non Firm Point to Point Transmission Service. (Corresponds to MISO Schedule 8.)
iii:			SSCD0	Charges for Scheduling System Control & Dispatch Scheduling and administering the movement of power into, out of, through, or within the Balancing Authority.
iv:			RSVC0	Charges for Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.
			SC020	Charges for Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.
2 A & B:	466			FERC Account: 466.1 Revenues from Transmission of Electricity of Others Subaccount: Primarily used to distinguish counterparty; Subaccount (Compliance Code) used to distinguish transmission revenues All MISO and Non-MISO revenues associated with the below listed items.
			MISO0	This is considered a miscellaneous MISO transmission revenue transaction and is not covered by other compliance codes listed herein as it is not a recurring item.
			SC240	RTO Schedule 24 - Control area recovery for cost recovery for providing balancing services as the Local Balancing Authority.

# Attachment F

			IFACD	Revenues arising from agreements authorized under Generator Interconnection Agreements (GIA) procedures under the MISO tariff.
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# Attachment F

i.			TSENO	Transmission Sales related to Network Transmission Services (Schedule 9) - Network Electric service is traditionally provided by bundling the generation, transmission, and distribution services. Through unbundling, the services can be separated which results in separate pricing and different suppliers or sources for each of the components. NITS represents the transmission service portion, these are covered by our long-term reservation. Ameren Missouri has three MISO NITS reservations - one for its native load in the AMMO pricing zone; one for its native load in the Entergy Arkansas pricing zone and a separate reservation to serve the City of Perryville. Ameren Missouri's designated resources (Ameren Missouri's generation portfolio) are designated to serve these loads.
ii.			SC070	RTO amounts for Schedule 7 - Firm Point to Point Transmission Service Point to Point service uses the transmission system to transmit energy from one point to another. Point to Point can be Firm (service can NOT be interrupted) or Non-Firm (service can be interrupted). This is typically associated with bilateral contracts.
			SC080	RTO amounts for Schedule 8 - Non-Firm Point to Point Transmission Service Point to Point service uses the transmission system to transmit energy from one point to another. Point to Point can be Firm (service can NOT be interrupted) or Non-Firm (service can be interrupted). This is typically associated with bilateral contracts.
iii.			SC010	RTO amounts for Schedule 1 - Scheduling System Control & Dispatch Scheduling and administering the movement of power into, out of, through, or within the MISO Balancing Authority.
iv.		All subaccounts excluding SPP	SC020	RTO amounts for Schedule 2 - Reactive Supply & Voltage Control Operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits.
2 A v.				MISO Schedule 11 not currently in use. MISO uses Schedule 11 for Wholesale Distribution Service and Pass Through Charges, which are charges that may not be easily identified and associated with a particular schedule.
vi.			SC260	RTO amounts for Schedule 26 - Network Upgrades Transmission Expansion Transmission charge for Network Upgrade Charge from Transmission Expansion Plan under the Regional Expansion Criteria and Benefits (RECB) provisions of the Tariff which is composed of Attachment FF, Attachment GG and Schedule 26. MISO Attachment GG prescribes the revenue requirement calculation for Schedule 26 charges. Historically, the MISO Tariff has included the following types of projects eligible for regional allocation under Attachment GG: <ul style="list-style-type: none"> <li>&gt; Market Efficiency Projects</li> <li>&gt; Generator Interconnections if they are 345kV</li> <li>&gt; Certain reliability projects approved before 2013 (such as the Company's Lutesville-Heritage line)</li> </ul> Cost allocation to pricing zones is performed when project approved based upon project type and voltage. <ul style="list-style-type: none"> <li>&gt; Market Efficiency                             <ul style="list-style-type: none"> <li>- 20% allocated MISO-wide based on load</li> <li>- 80% allocated to Local Resource Zone based on benefits</li> </ul> </li> <li>&gt; Reliability projects approved prior to 2013 Tariff change                             <ul style="list-style-type: none"> <li>- 345kV facilities - 20% allocated MISO-wide based on load</li> <li>- Remaining facilities allocated sub-regionally based on LODF (Line Outage Distribution Factor)</li> </ul> </li> <li>&gt; Generator Interconnections                             <ul style="list-style-type: none"> <li>- Per terms of MISO Attachment X - Generally paid by generator</li> </ul> </li> </ul>
			S26A0	RTO amounts for Schedule 26A - Multi Value Projects MVP is a transmission planning and cost allocation project category for projects that qualify based on multiple reliability and/or economic criteria affecting multiple transmission zones. MISO Attachment MM prescribes revenues to be collected under Schedule 26-A. Schedule 26A specifically involves a portfolio of Multi-Value Projects (MVPs) across MISO approved by the MISO Board in December 2011, whereas Schedule 26 is more regional in nature. <ul style="list-style-type: none"> <li>• Must meet at least one of the following Criteria to be an MVP                             <ul style="list-style-type: none"> <li>&gt; Developed through MISO planning process and support energy policy</li> <li>&gt; Provide multiple types of economic value across multiple pricing zones with benefit to cost ratio</li> </ul> </li> <li>&gt; 1                             <ul style="list-style-type: none"> <li>&gt; Address at least one:                                     <ul style="list-style-type: none"> <li>- Projected NERC violation</li> <li>- Economic-based issue</li> </ul> </li> <li>• MISO-wide allocation across MISO based on load</li> <li>&gt; Attachment MM format is very similar to Attachment GG</li> <li>&gt; Energy market settlement</li> <li>&gt; Currently MISO North load until end of transition period and then 8 year phase-in for MISO South</li> </ul> </li> </ul> AMMO Zone was approximately 7.5% of MISO North load in 2014
			SC370	RTO amounts for Schedule 37 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for American Transmission System, Inc. (ATSI) Zone Transmission charge that provides the mechanism for recovering a portion of the MTEP Projects constructed or approved by the MISO Board of Directors (approved prior to ATSI exit from MISO) for construction by ATSI upon ATSI's integration into PJM.
			SC380	RTO amounts for Schedule 38 - MISO Transmission Expansion Plan (MTEP) Project Cost Recovery for Duke Energy Ohio (DEO) and Duke Kentucky (DEK) Transmission charge that provides the mechanism for recovering a portion of the MTEP Projects constructed or approved by the MISO Board of Directors (approved prior to DEO/DEK exit from MISO) for construction by DEO/DEK upon DEO/DEK's integration into PJM.
vii.			SC330	RTO amounts for Schedule 33 - Black Start Service Charge to facilitate reliable and complete system restoration following a shut down of the bulk power Transmission System. Blackstart Service enables Transmission Operators to designate specific generation facilities as Blackstart Units whose location and capabilities are required to assist in re-energizing a specific portion of the Transmission System following a system-wide blackout.
viii.			SC410	Charge to Recover Costs of Entergy Storm Securitization Charges from Entergy Operating Companies' Pricing Zones
			S42A0	Charge to Recover Accrued and Paid Interest Associated with Prepayments From Entergy Operating Companies' Pricing Zones
			S42B0	Credit Associated with AFUDC From Entergy Operating Companies' Pricing Zones
			SC450	Cost Recovery of NERC Recommendations or Essential Action
			SC470	Entergy Operating Companies MISO Transition Cost Recovery

# Attachment F

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

\*Compliance Codes are same values as former Activity Codes with a zero added to the end (5 digits vs 4).

**EXCLUSIONS:**

FAC Subparagraph #	Account	Subaccount	Compliance Code	Description
	456			Revenues associated with FERC account 456.1 which are on MISO schedules specifically excluded from the FAC.
			SC100	RTO Schedule 10 - Cost Recovery Adder
	456			Revenues that are not currently part of FERC account 456.1 and therefore are not included in the FAC calculation.
			DFAC0	Wholesale Distribution Connection Facility revenues
			ACOS0	Accounting Offset
			GRTX0	Gross Receipts Tax
			ARSS0	Asset Recovery - Scrap & Salvage
			LMPM0	Property Management
			MFTR0	RTO Financial Transmission Rights
			MRNU0	RTO Revenue Neutrality Uplift
			NENR0	Non-Energy Revenues
			PLND0	Distribution Planning/Asset Performance
			REEAD	Renewable Energy/Energy Assistance
			RFRS0	RTO Ancillary Regulation & Frequency Reserve
			RQGR0	Customer Requests - Government Relocation
			SCOF0	Customer Sales - Off System
			SCON0	Customer Sales - On System
			SPRS0	RTO Ancillary Spinning
			SURS0	RTO Ancillary Supplemental
			TXPY0	Tax Payments
		SPP	SC020	Schedule 2 revenues (related to Atchison Energy Center, will be included in RESRAM)

**Notes:**  
 To the extent any amounts in the 565 account above relate to RES-compliance, these amounts will be excluded from the FAC and included in the RESRAM.

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For E = Costs and revenues for SO<sub>2</sub> and NO<sub>x</sub> emissions allowances in FERC accounts 411.8, 411.9 and 509

INCLUSIONS:

FAC Subparagraph #	Account	Subaccount	Compliance Code	Description
	411	008		FERC Account 411.8 contains gains from the disposition of emission allowances.
		009		FERC Account 411.9 contains losses on the disposition of emissions allowances.
	509	000		FERC Account 509 contains costs/revenues associated with consumption of emissions allowances such as purchase costs and hedging costs/revenues resulting from forward purchase contracts and financial instruments used to hedge emission allowance purchase costs.

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

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

INCLUSIONS:

FAC Subparagraph #	Account	Subaccount	Compliance Code	Description
	456	NEI	ACOS0	Net insurance recoveries for costs/revenues included in Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included Rider FAC.

Ameren Missouri  
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For OSSR = Costs and revenues in FERC account 447:

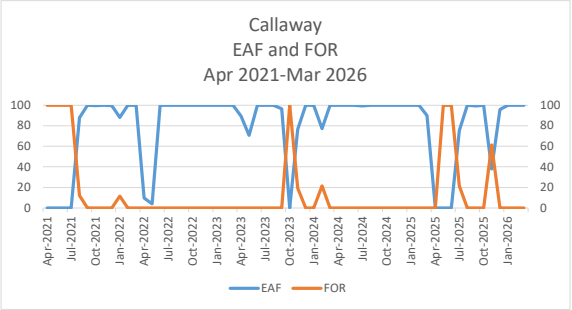
INCLUSIONS:

FAC Subparagraph #	Account	Subaccount	Compliance Code*	Description
1:	447			FERC Account 447 contains revenues related to net off-system sales Subaccount: used to distinguish various counterparties, subaccount XXX is for all hedging activity.
		All subaccounts	DERED	Sale of Capacity to various counterparties as identified by the subaccount. Subaccount MIS is used for transactions in MISO, subaccount PJM is used for transactions in the PJM, and subaccount SPP is for transactions in the Southern Power Pool. Revenue for MIS, PJM, and SPP subaccounts include capacity sales in the RTO's capacity market and for bilateral contracts. Except where carved out below, all other subaccounts represent bilateral deals with counterparties. Revenue from the sale of capacity under contract to municipalities is included in this compliance code.
2:		All subaccounts except XXX	ENERO	Sale of Energy to various counterparties as identified by the subaccount. Subaccount MIS is used for transactions in MISO, subaccount PJM is used for transactions in the PJM, and subaccount SPP is for transactions in the Southern Power Pool. Except where carved out below, all other subaccounts represent bilateral deals with counterparties.
			SCOND	Sales of Energy to various counterparties for Resale as identified by the subaccount.
			MSSRO	Costs and revenues associated with generation units designated as System Support Resources (SSR) by an RTO.
3:		998	ADMND	Supplier fees associated participation in Illinois Power Agency procurements.
			All subaccounts	SRMPO
A:			UNRSO	Uncertainty Reserve refers to an Operating Reserve Requirement that is procured from portions of dispatchable/participating resource's capability in response to planned and/or unplanned obligation changes.
			MSTRO	The Short-Term Reserve ancillary service product provides reserved and rampable capacity and compensates the online and offline generation resources that can produce energy within a 30-minute response time.
			RFRSO	Ancillary Services - Regulating Reserve - Schedule 3 credits Regulating Reserve refers to capacity held in reserve as directed by MISO by a frequency responsive resource owned by Ameren Missouri, for the purpose of automatically and continuously adjusting its output to maintain the supply/demand balance in the MISO balancing authority area in accordance with applicable reliability standards. RFRG costs are recorded in account 555.
			NRGAO	Ancillary Services - Regulating Reserve Service A MISO charge for Real Time Net Regulation Adjustment Amount. This charge type represents charges or credits to a Resource providing deployed Regulation Service such that the Resource is indifferent to deploying Energy above or below its Dispatch Target for Energy to provide the Regulation Services.
B:			DEDCO	Ancillary Services - Regulating Reserve Service This is a "Real Time Excessive/Deficient Energy Deployment Charge" which is a MISO charge that represents the charge to an Asset Owner owning Generation where the Asset Owner's unit fails to follow MISO setpoint instructions for 4 consecutive intervals within 1 hour without an exception.  SPP's "Regulation Non-Performance Distribution" corresponds to the MISO Excess/Deficient Energy Deployment Charge.
			ASMPO	Ancillary regulating reserve service balancing charge - Schedule 3 (reduction in revenue) Recapture of ancillary regulating reserve revenues received for Ameren Missouri generating units not deployed.
C:			ENERO	Sale of Energy MISO accounts for energy imbalance through the operation of the Real-Time Energy Market, which charges are included in the net energy amount reported in 2 above.
			SPRSO	Ancillary Services - Spinning Reserve - Schedule 5 credits Spinning Reserve refers to a portion of an operating resource capability which is held back (reserved) by Ameren Missouri. Spinning reserve must be able to be converted to energy within ten minutes of being instructed by MISO to deploy. SPRS costs are recorded in account 555.
D:			ASMPO	Ancillary supplemental reserve service balancing charge - Schedule 6 (reduction in revenue) Recapture of ancillary supplemental reserve revenues from for Ameren Missouri generating units not deployed.
			SURSO	Ancillary Services - Supplemental Reserve - Schedule 6 credits Supplemental Reserve refers to a non-synchronized (off-line) Ameren Missouri resource which can be converted to energy within ten minutes of being instructed by MISO to deploy. SURS costs are recorded in account 555.
4 A:			ASMPO	Ancillary supplemental reserve service balancing charge - Schedule 6 (reduction in revenue) Recapture of ancillary supplemental reserve revenues for Ameren Missouri generating units not deployed.
			PMWPO	Price volatility Make Whole Payment A MISO charge for Real Time Price Volatility Make-Whole Payment Amount. This charge provides compensation for market conditions that would erode the margin earned.
B:			DMWPO	Day-Ahead RSG Make Whole Payment A MISO charge for Day Ahead Revenue Sufficiency Guarantee Make Whole Payment. This is a charge type for the guaranteed recovery of production offers for Resources committed by MISO for the Day-Ahead Market.
			RMWPO	Real-Time RSG Make Whole Payment A MISO charge for Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount. This is a charge type for the guaranteed recovery of production offers for Resources committed by MISO for the Real-Time market.
5:		XXX	ENERO	Hedging costs/revenues resulting from forward purchase contracts, call options, and financial instruments used to hedge power transactions.
		002	ADMND	Broker fees related to power hedging activity

Notes:  
DA means the Day-Ahead energy market.  
RT means the actual delivered energy (Real Time)  
Net off-system sales, interchange sale and net sales other than native load are the same thing.  
To the extent any amounts in the accounts above relate to REG-compliance, these amounts will be excluded from the FAC and included in the RESRAM.  
\* Compliance Codes are same values as former Activity Codes with a zero added to the end (5 digits vs 4).

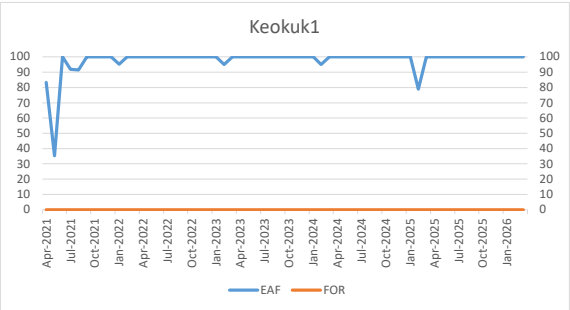
Callaway - Callaway 1

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Jun-2021	0	100
Jul-2021	0	100
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Sep-2021	99.83	0
Oct-2021	99.76	0
Nov-2021	99.81	0
Dec-2021	99.76	0
Jan-2022	88.27	11.55
Feb-2022	99.84	0
Mar-2022	99.84	0
Apr-2022	9.66	0
May-2022	3.95	0
Jun-2022	99.81	0
Jul-2022	99.89	0
Aug-2022	99.92	0
Sep-2022	99.92	0
Oct-2022	99.98	0
Nov-2022	99.99	0
Dec-2022	99.99	0
Jan-2023	99.99	0
Feb-2023	99.84	0
Mar-2023	99.92	0
Apr-2023	89.35	0
May-2023	70.52	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	96.38	0
Oct-2023	0	100
Nov-2023	76.54	19.29
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	77.02	21.57
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	99.41	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	89.9	0
Apr-2025	0	0
May-2025	0	100
Jun-2025	0	100
Jul-2025	75.2	21.37
Aug-2025	99.83	0
Sep-2025	99.39	0
Oct-2025	99.86	0
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Jan-2026	100	0
Feb-2026	100	0
Mar-2026	99.92	0



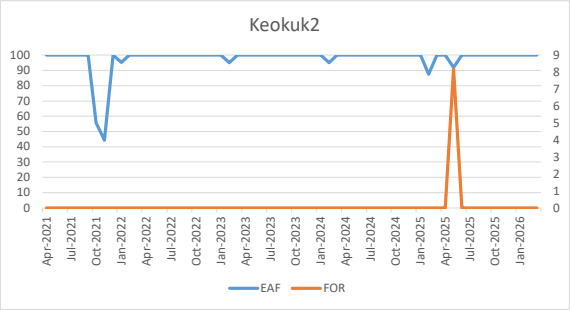
Keokuk - Keokuk 1

DATE	EAF	FOR
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Aug-2021	91.4	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.36	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	94.94	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	94.97	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	78.87	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



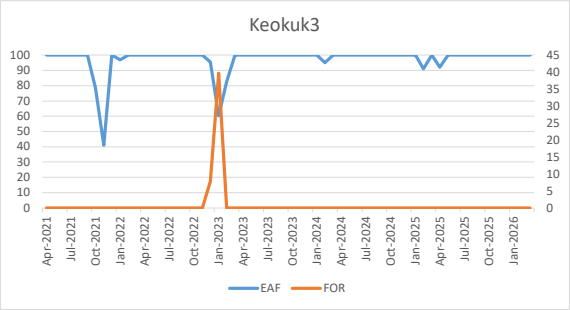
Keokuk - Keokuk 2

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Jun-2021	100	0
Jul-2021	100	0
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Sep-2021	100	0
Oct-2021	55.7	0
Nov-2021	44.33	0
Dec-2021	100	0
Jan-2022	95.36	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	94.94	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	95.04	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	87.5	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	91.83	8.17
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
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Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



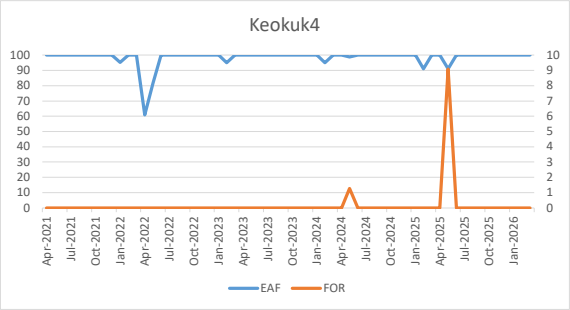
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DATE	EAF	FOR
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Jul-2021	100	0
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Sep-2021	100	0
Oct-2021	78.42	0
Nov-2021	40.99	0
Dec-2021	100	0
Jan-2022	96.77	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	95.43	7.82
Jan-2023	60.37	39.63
Feb-2023	82.66	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	95.02	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
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Dec-2024	100	0
Jan-2025	100	0
Feb-2025	91.07	0
Mar-2025	100	0
Apr-2025	91.93	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
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Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



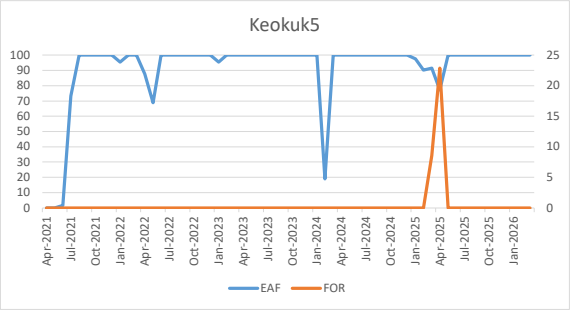
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Jul-2021	100	0
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Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.36	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	60.97	0
May-2022	81.72	0
Jun-2022	100	0
Jul-2022	100	0
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Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	94.94	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
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Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	94.94	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	98.72	1.28
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
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Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	91.07	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	90.91	9.09
Jun-2025	100	0
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Sep-2025	100	0
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Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



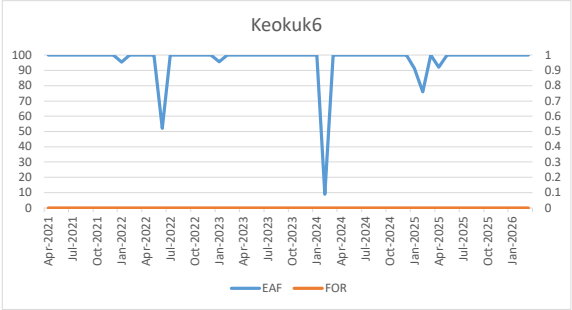
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Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	87.64	0
May-2022	68.82	0
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May-2023	100	0
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Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
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Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	19.11	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	97.58	0
Feb-2025	90.18	0
Mar-2025	91.41	8.59
Apr-2025	77.16	22.84
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
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Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



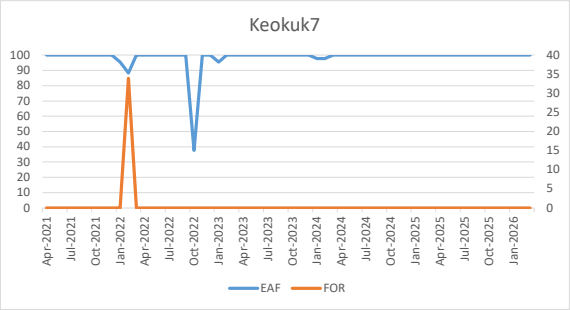
Keokuk - Keokuk 6

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	52.08	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.56	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	8.98	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	91.13	0
Feb-2025	75.89	0
Mar-2025	100	0
Apr-2025	91.93	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



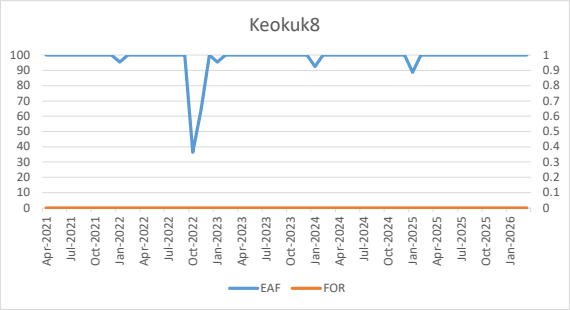
Keokuk - Keokuk 7

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	88.32	33.91
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	37.57	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	97.72	0
Feb-2024	97.7	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



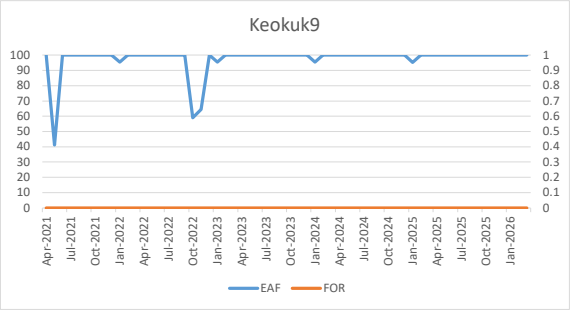
Keokuk - Keokuk 8

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	36.45	0
Nov-2022	64.19	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	92.47	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	88.71	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



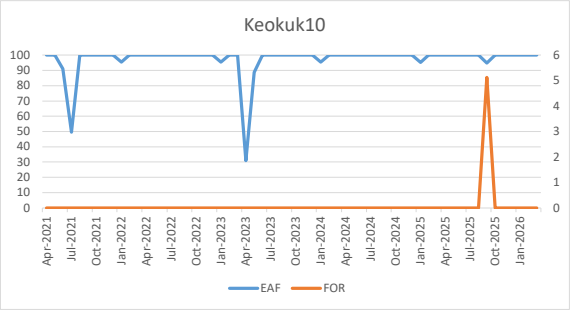
Keokuk - Keokuk 9

DATE	EAF	FOR
Apr-2021	100	0
May-2021	41.26	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	59.04	0
Nov-2022	64.32	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	95.43	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



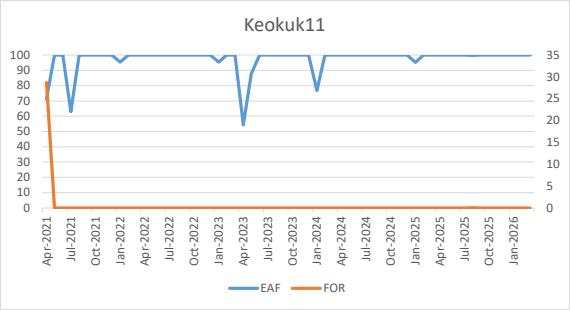
Keokuk - Keokuk 10

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	91.03	0
Jul-2021	49.46	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	30.97	0
May-2023	88.62	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	95.43	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	94.88	5.12
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



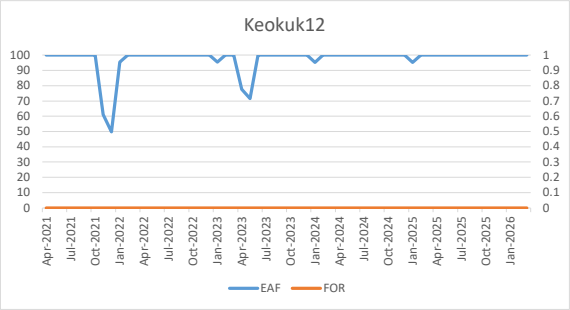
Keokuk - Keokuk 11

DATE	EAF	FOR
Apr-2021	71.26	28.74
May-2021	100	0
Jun-2021	100	0
Jul-2021	63.1	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	54.31	0
May-2023	87.89	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	76.75	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	99.97	0.03
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



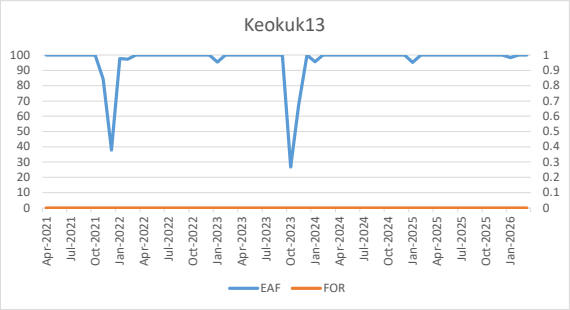
Keokuk - Keokuk 12

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	61.08	0
Dec-2021	49.89	0
Jan-2022	95.43	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	77.64	0
May-2023	71.51	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	95.36	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



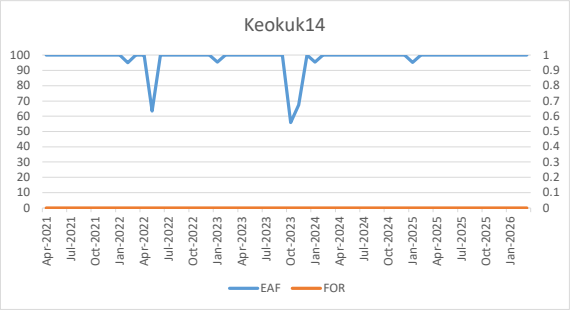
Keokuk - Keokuk 13

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	84.39	0
Dec-2021	37.9	0
Jan-2022	97.74	0
Feb-2022	97.44	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	26.75	0
Nov-2023	67.48	0
Dec-2023	100	0
Jan-2024	95.5	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	98.42	0
Feb-2026	100	0
Mar-2026	100	0



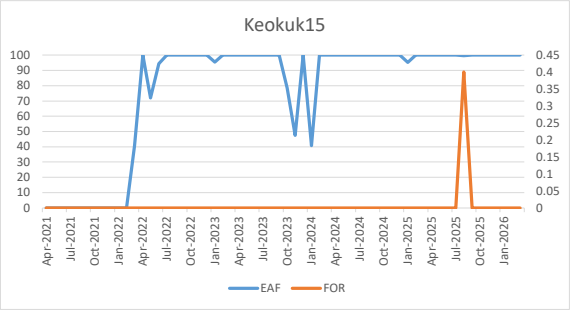
Keokuk - Keokuk 14

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	94.94	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	63.31	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	55.78	0
Nov-2023	67.48	0
Dec-2023	100	0
Jan-2024	95.43	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



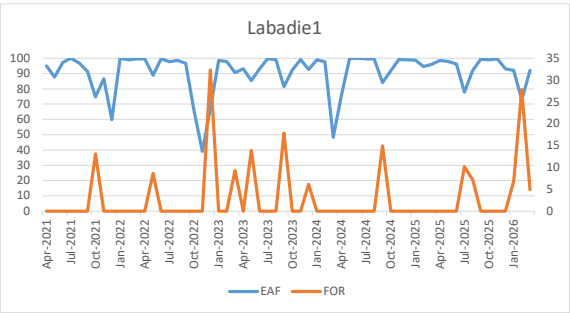
Keokuk - Keokuk 15

DATE	EAF	FOR
Apr-2021	0	0
May-2021	0	0
Jun-2021	0	0
Jul-2021	0	0
Aug-2021	0	0
Sep-2021	0	0
Oct-2021	0	0
Nov-2021	0	0
Dec-2021	0	0
Jan-2022	0	0
Feb-2022	0	0
Mar-2022	40.51	0
Apr-2022	100	0
May-2022	71.91	0
Jun-2022	94.44	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	95.43	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	78.36	0
Nov-2023	47.5	0
Dec-2023	100	0
Jan-2024	40.73	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	95.16	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	99.6	0.4
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



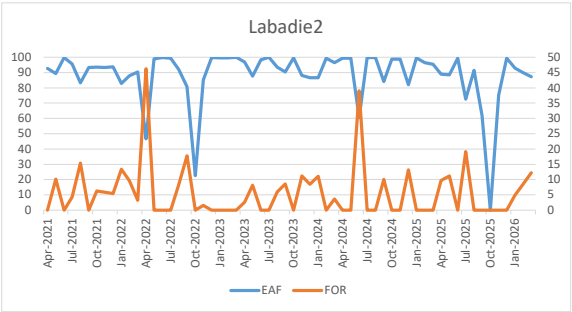
Labadie - Labadie 1

DATE	EAF	FOR
Apr-2021	95.18	0
May-2021	87.84	0
Jun-2021	97.43	0
Jul-2021	99.96	0
Aug-2021	96.85	0
Sep-2021	91.65	0
Oct-2021	74.77	13.09
Nov-2021	86.77	0
Dec-2021	59.9	0
Jan-2022	100	0
Feb-2022	99.02	0
Mar-2022	99.77	0
Apr-2022	99.8	0
May-2022	89.06	8.62
Jun-2022	99.64	0
Jul-2022	97.78	0
Aug-2022	98.61	0
Sep-2022	96.83	0
Oct-2022	65.81	0
Nov-2022	39.17	0
Dec-2022	67.3	32.32
Jan-2023	98.65	0
Feb-2023	97.9	0
Mar-2023	90.64	9.32
Apr-2023	93.25	0
May-2023	85.36	13.96
Jun-2023	93.08	0
Jul-2023	99.95	0
Aug-2023	99.07	0
Sep-2023	81.43	17.85
Oct-2023	92.38	0
Nov-2023	99.21	0
Dec-2023	92.81	6.17
Jan-2024	99.05	0
Feb-2024	97.76	0
Mar-2024	48.25	0
Apr-2024	76.21	0
May-2024	99.86	0
Jun-2024	100	0
Jul-2024	99.72	0
Aug-2024	99.71	0
Sep-2024	84.18	14.94
Oct-2024	91.91	0
Nov-2024	99.37	0
Dec-2024	99	0
Jan-2025	98.83	0
Feb-2025	94.67	0
Mar-2025	96.08	0
Apr-2025	98.61	0
May-2025	97.99	0
Jun-2025	96.29	0
Jul-2025	77.88	10.22
Aug-2025	92.08	7.13
Sep-2025	99.46	0
Oct-2025	98.98	0
Nov-2025	99.64	0
Dec-2025	93.27	0
Jan-2026	92.07	6.88
Feb-2026	72.79	27.81
Mar-2026	92.22	4.92



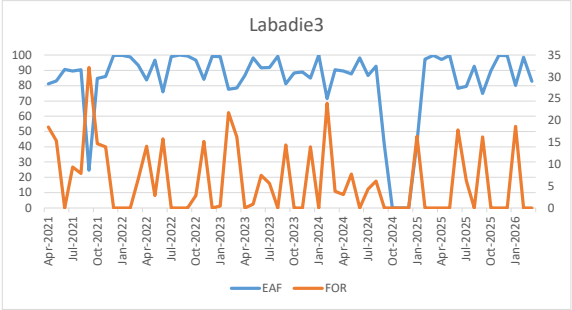
Labadie - Labadie 2

DATE	EAF	FOR
Apr-2021	92.86	0
May-2021	89.45	10.15
Jun-2021	99.94	0
Jul-2021	95.67	4.33
Aug-2021	83.37	15.38
Sep-2021	93.28	0
Oct-2021	93.67	6.2
Nov-2021	93.36	5.86
Dec-2021	93.87	5.46
Jan-2022	82.82	13.42
Feb-2022	87.87	9.62
Mar-2022	90.48	3.24
Apr-2022	46.84	46.28
May-2022	98.94	0
Jun-2022	99.9	0
Jul-2022	99.44	0
Aug-2022	92.05	8.23
Sep-2022	80.89	17.78
Oct-2022	22.55	0
Nov-2022	85.2	1.54
Dec-2022	99.92	0
Jan-2023	99.67	0
Feb-2023	99.8	0
Mar-2023	100	0
Apr-2023	96.87	2.61
May-2023	87.7	8.15
Jun-2023	98.34	0
Jul-2023	99.99	0
Aug-2023	93.63	6.02
Sep-2023	90.57	8.55
Oct-2023	99.72	0
Nov-2023	88.25	11.26
Dec-2023	86.7	8.45
Jan-2024	86.78	11.14
Feb-2024	99.38	0
Mar-2024	96.57	3.63
Apr-2024	99.48	0
May-2024	99.47	0
Jun-2024	60.58	38.99
Jul-2024	99.89	0
Aug-2024	99.94	0
Sep-2024	84.08	10.04
Oct-2024	98.87	0
Nov-2024	98.87	0
Dec-2024	82.11	13.19
Jan-2025	99.64	0
Feb-2025	96.54	0
Mar-2025	95.43	0
Apr-2025	89.02	9.68
May-2025	88.53	11.19
Jun-2025	99.38	0
Jul-2025	72.72	19.2
Aug-2025	91.48	0
Sep-2025	61.84	0
Oct-2025	0	0
Nov-2025	75.43	0
Dec-2025	99.42	0
Jan-2026	92.97	4.92
Feb-2026	90.08	8.5
Mar-2026	87.24	12.26



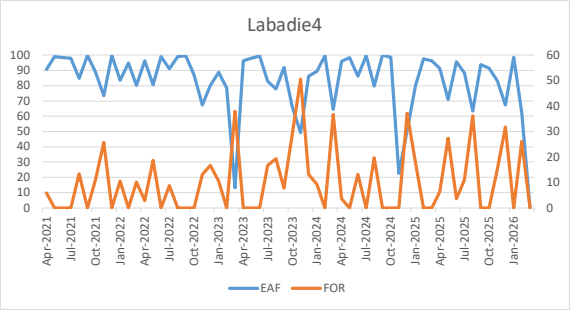
Labadie - Labadie 3

DATE	EAF	FOR
Apr-2021	81.18	18.51
May-2021	82.94	15.35
Jun-2021	90.63	0
Jul-2021	89.57	9.37
Aug-2021	90.33	7.89
Sep-2021	24.78	32.13
Oct-2021	84.75	14.71
Nov-2021	86.15	14
Dec-2021	99.92	0
Jan-2022	99.97	0
Feb-2022	98.73	0
Mar-2022	93.31	6.66
Apr-2022	83.76	14.12
May-2022	96.73	2.82
Jun-2022	76.03	15.84
Jul-2022	98.86	0
Aug-2022	99.99	0
Sep-2022	99.43	0
Oct-2022	96.57	2.81
Nov-2022	84.05	15.23
Dec-2022	99.21	0
Jan-2023	98.98	0.43
Feb-2023	77.68	21.78
Mar-2023	78.48	16.28
Apr-2023	86.55	0
May-2023	98.11	0.88
Jun-2023	91.66	7.49
Jul-2023	91.91	5.66
Aug-2023	99.27	0
Sep-2023	81.29	14.41
Oct-2023	88.38	0
Nov-2023	88.87	0
Dec-2023	85	14.04
Jan-2024	100	0
Feb-2024	71.53	23.95
Mar-2024	90.51	3.85
Apr-2024	89.53	3.07
May-2024	87.57	7.79
Jun-2024	98.08	0
Jul-2024	86.63	4.36
Aug-2024	92.81	6.17
Sep-2024	41.15	0
Oct-2024	0	0
Nov-2024	0	0
Dec-2024	0	0
Jan-2025	42.98	16.42
Feb-2025	97.38	0
Mar-2025	99.81	0
Apr-2025	97.17	0
May-2025	99.8	0
Jun-2025	78.25	17.85
Jul-2025	79.4	6.33
Aug-2025	92.78	0
Sep-2025	74.84	16.25
Oct-2025	89.66	0
Nov-2025	99.94	0
Dec-2025	99.55	0
Jan-2026	80.17	18.65
Feb-2026	98.54	0
Mar-2026	82.86	0



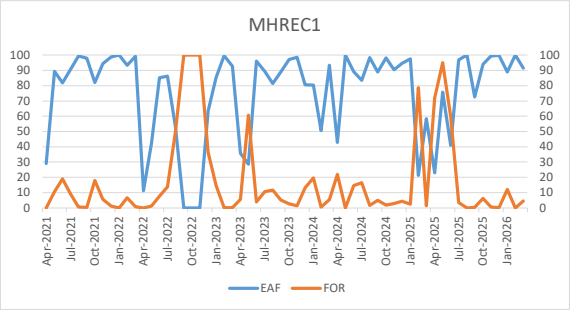
Labadie - Labadie 4

DATE	EAF	FOR
Apr-2021	90.76	5.91
May-2021	99.02	0
Jun-2021	98.34	0
Jul-2021	97.9	0
Aug-2021	84.76	13.43
Sep-2021	99.97	0
Oct-2021	88.86	10.96
Nov-2021	73.43	25.71
Dec-2021	99.75	0
Jan-2022	83.55	10.51
Feb-2022	94.75	0
Mar-2022	80.08	10.15
Apr-2022	96.29	2.94
May-2022	80.63	18.73
Jun-2022	98.92	0
Jul-2022	90.94	8.85
Aug-2022	99.03	0
Sep-2022	99.61	0
Oct-2022	87.04	0
Nov-2022	67.31	13.11
Dec-2022	80.17	16.73
Jan-2023	88.62	10.5
Feb-2023	78.44	0
Mar-2023	13.2	37.94
Apr-2023	96.37	0
May-2023	97.87	0
Jun-2023	99.3	0
Jul-2023	82.85	16.64
Aug-2023	77.84	19.25
Sep-2023	91.85	7.74
Oct-2023	66.16	28.96
Nov-2023	49.16	50.59
Dec-2023	86.24	13.13
Jan-2024	89.3	9.3
Feb-2024	99.6	0
Mar-2024	64.4	36.68
Apr-2024	95.73	3.66
May-2024	98.3	0
Jun-2024	86.25	13.14
Jul-2024	99.63	0
Aug-2024	79.82	19.68
Sep-2024	100	0
Oct-2024	98.66	0
Nov-2024	22.72	0
Dec-2024	50.59	37.16
Jan-2025	79.89	17.85
Feb-2025	97.62	0
Mar-2025	96.3	0
Apr-2025	91.13	6.35
May-2025	70.88	27.37
Jun-2025	95.53	3.61
Jul-2025	88.25	11.07
Aug-2025	63.4	36.14
Sep-2025	93.7	0
Oct-2025	91.52	0
Nov-2025	83.13	15.27
Dec-2025	67.37	31.75
Jan-2026	98.61	0
Feb-2026	62.58	26.14
Mar-2026	0	0



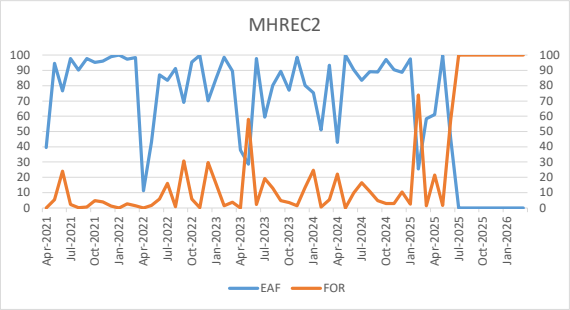
Maryland Heights Renewable Energy Center - Maryland Heights 1

DATE	EAF	FOR
Apr-2021	29.12	0
May-2021	89.3	10.7
Jun-2021	81.78	19.04
Jul-2021	90.76	9.24
Aug-2021	99.4	0.62
Sep-2021	97.82	0.46
Oct-2021	81.92	18.08
Nov-2021	94.36	5.64
Dec-2021	98.71	1.29
Jan-2022	100	0
Feb-2022	93.28	6.72
Mar-2022	99.14	0.86
Apr-2022	11.33	0
May-2022	42.22	1.29
Jun-2022	85.23	7.78
Jul-2022	86.17	13.67
Aug-2022	52.88	50
Sep-2022	0	100
Oct-2022	0	100
Nov-2022	0	100
Dec-2022	63.38	36.51
Jan-2023	85.26	14.74
Feb-2023	99.73	0.27
Mar-2023	92.77	0.25
Apr-2023	35.68	5.68
May-2023	28.71	60.74
Jun-2023	96.03	3.97
Jul-2023	89.43	10.64
Aug-2023	81.38	11.62
Sep-2023	88.86	5.2
Oct-2023	97.14	2.62
Nov-2023	98.59	1.41
Dec-2023	80.47	13.1
Jan-2024	80.33	19.67
Feb-2024	50.63	0.68
Mar-2024	93.25	5.53
Apr-2024	42.89	21.92
May-2024	100	0
Jun-2024	89.26	14.78
Jul-2024	83.42	16.58
Aug-2024	98.42	1.59
Sep-2024	88.81	5.01
Oct-2024	98.02	1.98
Nov-2024	90.49	3.02
Dec-2024	94.58	4.39
Jan-2025	97.59	2.45
Feb-2025	21.32	78.68
Mar-2025	58.48	1.35
Apr-2025	22.92	72.1
May-2025	75.69	94.99
Jun-2025	41.03	59.89
Jul-2025	96.81	3.57
Aug-2025	100	0
Sep-2025	72.67	0.37
Oct-2025	93.97	6.25
Nov-2025	99.51	0.54
Dec-2025	99.82	0.21
Jan-2026	88.9	12.22
Feb-2026	100	0
Mar-2026	91.55	4.55



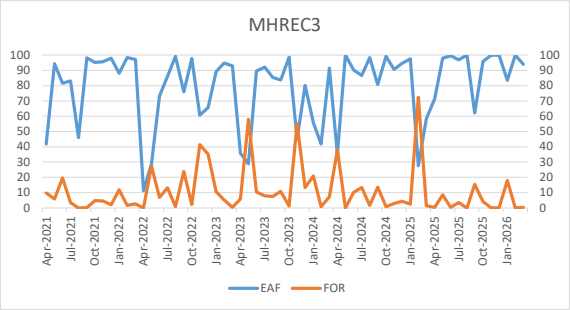
Maryland Heights Renewable Energy Center - Maryland Heights 2

DATE	EAF	FOR
Apr-2021	39.55	0
May-2021	94.5	5.55
Jun-2021	76.5	24.09
Jul-2021	97.74	2.26
Aug-2021	90.08	0.08
Sep-2021	97.7	0.7
Oct-2021	95.31	4.69
Nov-2021	96.02	3.98
Dec-2021	98.83	1.17
Jan-2022	100	0
Feb-2022	97.23	2.77
Mar-2022	98.44	1.56
Apr-2022	11.27	0
May-2022	43.06	1.66
Jun-2022	87.05	5.77
Jul-2022	83.4	16.16
Aug-2022	91.34	0.85
Sep-2022	69.09	30.91
Oct-2022	95.45	5.79
Nov-2022	99.94	0.07
Dec-2022	70.12	29.75
Jan-2023	84.82	15.67
Feb-2023	98.56	1.44
Mar-2023	89.5	3.76
Apr-2023	37.88	0
May-2023	28.72	58.04
Jun-2023	97.78	2.22
Jul-2023	59.36	19.39
Aug-2023	80.14	13.02
Sep-2023	89.3	4.72
Oct-2023	76.97	3.5
Nov-2023	98.49	1.51
Dec-2023	80.28	13.33
Jan-2024	75.35	24.65
Feb-2024	50.98	0.65
Mar-2024	93.31	5.56
Apr-2024	42.81	22.08
May-2024	100	0
Jun-2024	90.43	9.76
Jul-2024	83.51	16.49
Aug-2024	89.14	10.86
Sep-2024	88.94	4.83
Oct-2024	96.99	3.01
Nov-2024	90.52	2.94
Dec-2024	88.63	10.41
Jan-2025	97.59	2.46
Feb-2025	25.57	73.95
Mar-2025	58.48	1.35
Apr-2025	61.14	21.59
May-2025	99.57	1.74
Jun-2025	45.51	57.45
Jul-2025	0	100
Aug-2025	0	100
Sep-2025	0	100
Oct-2025	0	100
Nov-2025	0	100
Dec-2025	0	100
Jan-2026	0	100
Feb-2026	0	100
Mar-2026	0	100



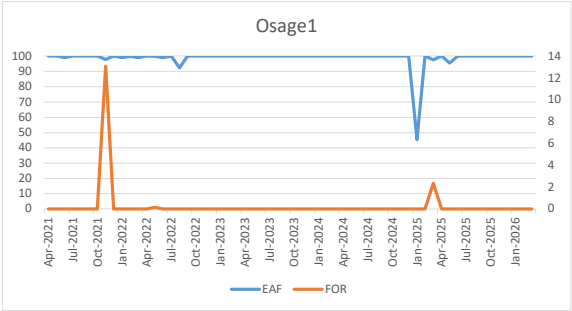
Maryland Heights Renewable Energy Center - Maryland Heights 3

DATE	EAF	FOR
Apr-2021	41.87	9.78
May-2021	94.25	5.79
Jun-2021	81.56	19.53
Jul-2021	83.04	3.5
Aug-2021	45.99	0
Sep-2021	98.14	0.28
Oct-2021	95.27	4.73
Nov-2021	95.53	4.47
Dec-2021	97.97	2.03
Jan-2022	88.17	11.83
Feb-2022	98.3	1.7
Mar-2022	97.21	2.79
Apr-2022	11.29	0
May-2022	28.82	27.39
Jun-2022	73.25	6.75
Jul-2022	86.1	13.2
Aug-2022	99.23	0.84
Sep-2022	76.03	23.97
Oct-2022	97.69	2.23
Nov-2022	60.8	41.44
Dec-2022	65.58	35.17
Jan-2023	89.26	10.74
Feb-2023	94.74	5.26
Mar-2023	93.05	0.42
Apr-2023	35.7	5.72
May-2023	28.81	57.87
Jun-2023	89.57	10.43
Jul-2023	92.07	7.98
Aug-2023	85.38	7.56
Sep-2023	83.72	10.81
Oct-2023	98.48	1.28
Nov-2023	44.92	55.08
Dec-2023	80.29	13.37
Jan-2024	55.76	20.9
Feb-2024	41.9	0.8
Mar-2024	91.55	7.25
Apr-2024	35.24	37.99
May-2024	100	0
Jun-2024	90.15	10.28
Jul-2024	86.57	13.43
Aug-2024	98.29	1.76
Sep-2024	80.82	13.55
Oct-2024	99.19	0.81
Nov-2024	90.54	2.94
Dec-2024	94.57	4.41
Jan-2025	97.58	2.47
Feb-2025	27.67	72.33
Mar-2025	58.48	1.35
Apr-2025	71.29	0.47
May-2025	97.87	8.6
Jun-2025	99.66	0.36
Jul-2025	96.81	3.57
Aug-2025	100	0
Sep-2025	62.14	15.56
Oct-2025	95.86	4.29
Nov-2025	99.78	0.23
Dec-2025	100	0
Jan-2026	83.61	18.02
Feb-2026	100	0
Mar-2026	94.04	0.51



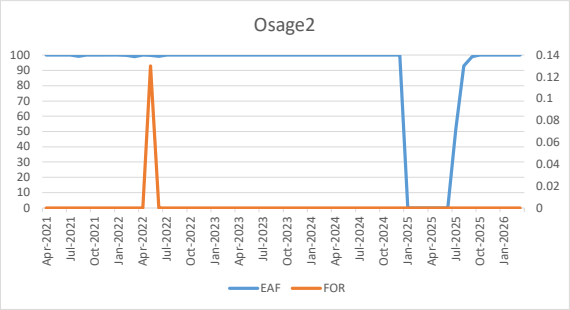
Osage - Osage 1

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	98.99	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	97.85	13.08
Dec-2021	100	0
Jan-2022	99.01	0
Feb-2022	99.93	0
Mar-2022	98.97	0
Apr-2022	100	0
May-2022	99.87	0.14
Jun-2022	99.1	0
Jul-2022	100	0
Aug-2022	92.47	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	45.43	0
Feb-2025	100	0
Mar-2025	97.64	2.36
Apr-2025	100	0
May-2025	95.37	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



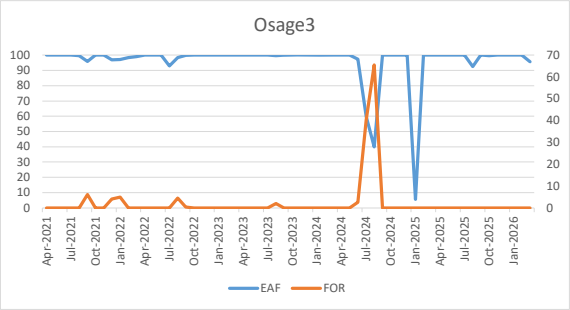
Osage - Osage 2

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	99.19	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	99.96	0
Mar-2022	98.97	0
Apr-2022	100	0
May-2022	99.87	0.13
Jun-2022	99.1	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	0	0
Feb-2025	0	0
Mar-2025	0	0
Apr-2025	0	0
May-2025	0	0
Jun-2025	0	0
Jul-2025	51.62	0
Aug-2025	92.88	0
Sep-2025	99.03	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



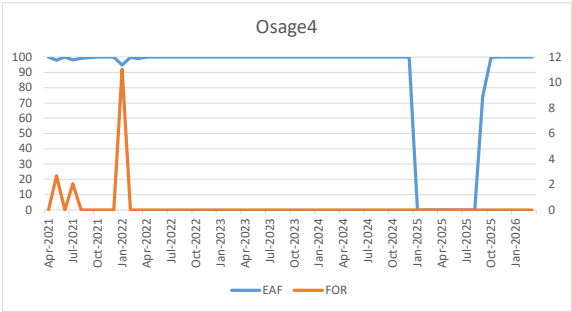
Osage - Osage 3

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	99.53	0
Sep-2021	95.94	6.2
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	96.81	4.15
Jan-2022	97.02	4.99
Feb-2022	98.47	0
Mar-2022	98.97	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	93	0
Aug-2022	98.46	4.55
Sep-2022	99.79	0.43
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	99.73	2
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	97.43	2.57
Jul-2024	59.74	40.26
Aug-2024	40.01	65.46
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	5.58	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	92.4	0
Sep-2025	100	0
Oct-2025	99.74	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	95.63	0



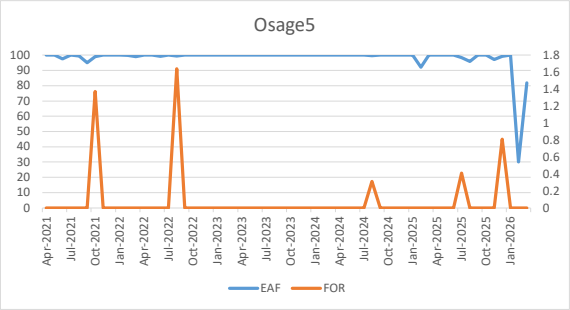
Osage - Osage 4

DATE	EAF	FOR
Apr-2021	100	0
May-2021	97.98	2.7
Jun-2021	100	0
Jul-2021	98.22	2.06
Aug-2021	99.06	0
Sep-2021	99.69	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	94.74	11.06
Feb-2022	99.96	0
Mar-2022	98.97	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	0	0
Feb-2025	0	0
Mar-2025	0	0
Apr-2025	0	0
May-2025	0	0
Jun-2025	0	0
Jul-2025	0	0
Aug-2025	0	0
Sep-2025	74.44	0
Oct-2025	99.75	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



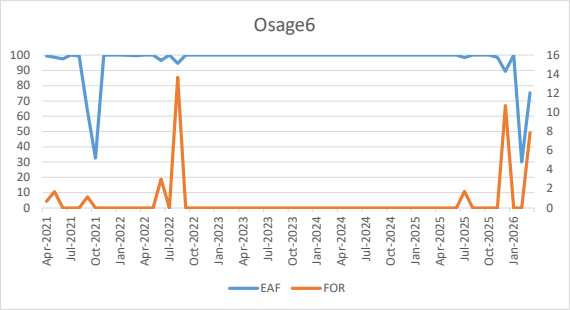
Osage - Osage 5

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	97.46	0
Jul-2021	100	0
Aug-2021	99.42	0
Sep-2021	95.12	0
Oct-2021	98.86	1.37
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	99.96	0
Mar-2022	98.97	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	99.24	0
Jul-2022	100	0
Aug-2022	99.33	1.64
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	99.69	0.31
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	92	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	98.45	0.41
Aug-2025	95.74	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	97.12	0
Dec-2025	99.19	0.81
Jan-2026	100	0
Feb-2026	30.11	0
Mar-2026	81.85	0



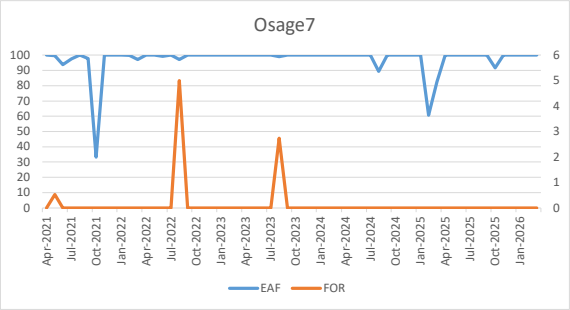
Osage - Osage 6

DATE	EAF	FOR
Apr-2021	99.32	0.71
May-2021	98.66	1.7
Jun-2021	97.46	0
Jul-2021	100	0
Aug-2021	99.42	0
Sep-2021	63.41	1.16
Oct-2021	32.65	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	99.96	0
Mar-2022	99.62	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	96.49	3.03
Jul-2022	100	0
Aug-2022	94.64	13.66
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	98.25	1.75
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	98.54	0
Dec-2025	89.3	10.7
Jan-2026	100	0
Feb-2026	30.13	0
Mar-2026	75.39	7.89



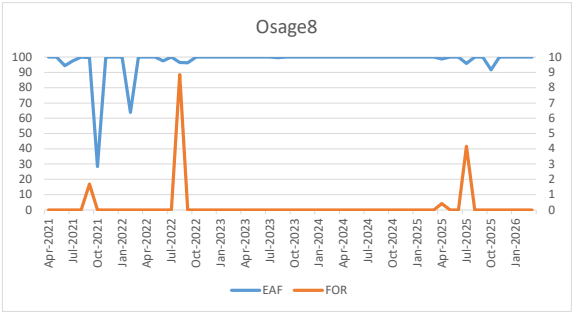
Osage - Osage 7

DATE	EAF	FOR
Apr-2021	100	0
May-2021	99.55	0.53
Jun-2021	93.85	0
Jul-2021	97.54	0
Aug-2021	100	0
Sep-2021	97.7	0
Oct-2021	33.28	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	99.96	0
Mar-2022	97.2	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	99.12	0
Jul-2022	100	0
Aug-2022	97.08	5
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	98.9	2.74
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	89.38	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	60.74	0
Mar-2025	82.58	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	91.69	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



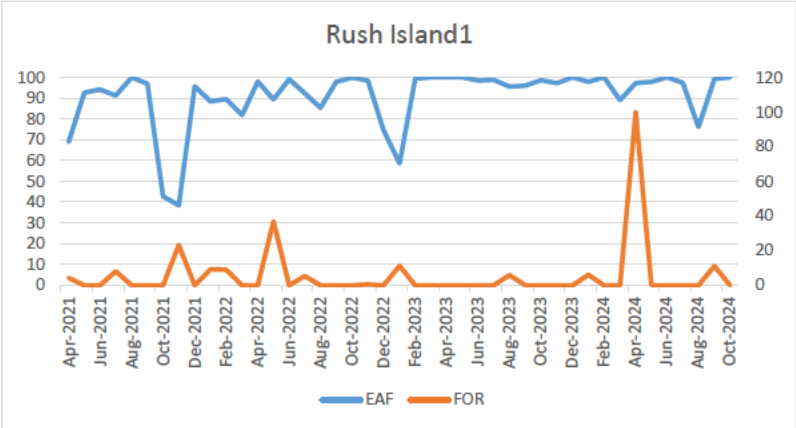
Osage - Osage 8

DATE	EAF	FOR
Apr-2021	100	0
May-2021	100	0
Jun-2021	94.27	0
Jul-2021	97.54	0
Aug-2021	100	0
Sep-2021	99.53	1.71
Oct-2021	28.51	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	63.81	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	97.67	0
Jul-2022	100	0
Aug-2022	96.49	8.86
Sep-2022	96.25	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	99.74	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	98.73	0.42
May-2025	100	0
Jun-2025	100	0
Jul-2025	95.83	4.17
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	91.69	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



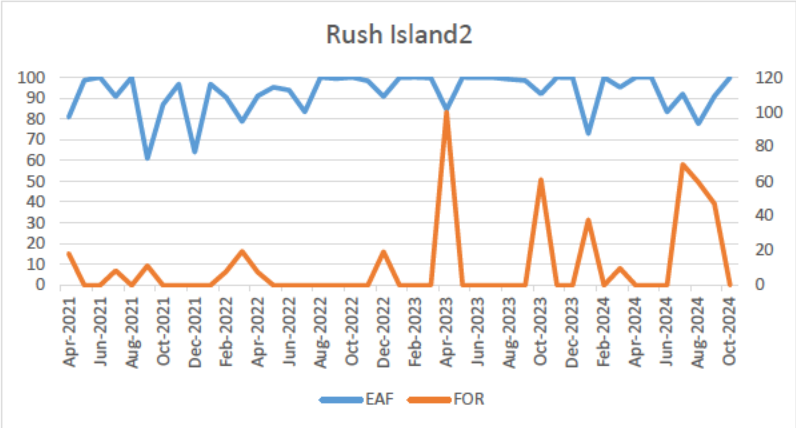
Rush Island - Rush Island 1

DATE	EAF	FOR
Apr-2021	69	4.27
May-2021	92.58	0
Jun-2021	94.13	0
Jul-2021	91.24	8.05
Aug-2021	100	0
Sep-2021	96.94	0
Oct-2021	42.77	0
Nov-2021	38.36	23.14
Dec-2021	95.66	0
Jan-2022	88.41	9.06
Feb-2022	89.49	8.92
Mar-2022	81.69	0
Apr-2022	98.01	0
May-2022	89.32	37.02
Jun-2022	99.03	0
Jul-2022	92.32	5.2
Aug-2022	85.24	0
Sep-2022	97.91	0
Oct-2022	99.8	0
Nov-2022	98.39	0.49
Dec-2022	74.53	0
Jan-2023	58.62	11.22
Feb-2023	99.32	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	98.49	0
Jul-2023	98.85	0
Aug-2023	95.43	5.89
Sep-2023	95.97	0
Oct-2023	98.51	0
Nov-2023	97.17	0
Dec-2023	100	0
Jan-2024	97.87	6.07
Feb-2024	100	0
Mar-2024	89.1	0
Apr-2024	97.29	100
May-2024	97.85	0
Jun-2024	100	0
Jul-2024	97.35	0
Aug-2024	76.22	0
Sep-2024	99.2	10.97
Oct-2024	100	0



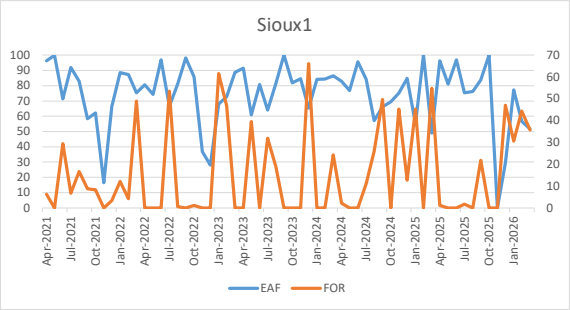
Rush Island - Rush Island 2

DATE	EAF	FOR
Apr-2021	80.71	18.51
May-2021	98.55	0
Jun-2021	100	0
Jul-2021	90.75	8.4
Aug-2021	100	0
Sep-2021	60.86	11.28
Oct-2021	86.81	0
Nov-2021	96.82	0
Dec-2021	63.94	0
Jan-2022	96.8	0
Feb-2022	90.37	8.01
Mar-2022	78.71	19.47
Apr-2022	91.02	7.49
May-2022	95.23	0
Jun-2022	93.86	0
Jul-2022	83.25	0
Aug-2022	100	0
Sep-2022	99.29	0
Oct-2022	100	0
Nov-2022	98.34	0
Dec-2022	90.75	19.34
Jan-2023	99.85	0
Feb-2023	100	0
Mar-2023	99.59	0
Apr-2023	84.44	100
May-2023	100	0
Jun-2023	99.78	0
Jul-2023	99.74	0
Aug-2023	99.05	0
Sep-2023	98.49	0
Oct-2023	91.98	60.95
Nov-2023	100	0
Dec-2023	99.87	0
Jan-2024	72.89	37.8
Feb-2024	100	0
Mar-2024	95.2	9.87
Apr-2024	100	0
May-2024	100	0
Jun-2024	83.41	0
Jul-2024	91.9	69.59
Aug-2024	77.71	59.47
Sep-2024	90.83	47.08
Oct-2024	100	0



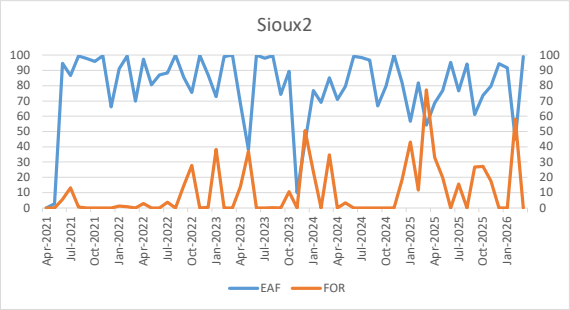
Sioux - Sioux 1

DATE	EAF	FOR
Apr-2021	96.19	6.32
May-2021	99.97	0
Jun-2021	71.29	29.51
Jul-2021	91.84	6.79
Aug-2021	82.9	16.68
Sep-2021	58.48	8.82
Oct-2021	62.2	8.36
Nov-2021	16.62	0
Dec-2021	66.46	3.33
Jan-2022	88.49	12.13
Feb-2022	87.27	4.17
Mar-2022	75.28	48.92
Apr-2022	80.57	0
May-2022	74.27	0
Jun-2022	96.86	0
Jul-2022	66.56	53.44
Aug-2022	81.22	0.54
Sep-2022	98.12	0
Oct-2022	85.75	1.16
Nov-2022	36.76	0
Dec-2022	27.93	0
Jan-2023	68	61.58
Feb-2023	72.87	46.72
Mar-2023	88.77	0
Apr-2023	91.53	0
May-2023	60.92	39.58
Jun-2023	80.68	0
Jul-2023	64.12	32.02
Aug-2023	81.66	18.66
Sep-2023	99.99	0
Oct-2023	81.75	0
Nov-2023	84.56	0
Dec-2023	65.27	66.1
Jan-2024	84.1	0
Feb-2024	84.42	0
Mar-2024	86.48	24.3
Apr-2024	82.74	2.22
May-2024	76.8	0
Jun-2024	95.59	0
Jul-2024	84.12	11.1
Aug-2024	57.16	26.1
Sep-2024	66.2	49.61
Oct-2024	69.36	0
Nov-2024	75.21	45.31
Dec-2024	84.84	12.71
Jan-2025	55.07	45.28
Feb-2025	100	0
Mar-2025	48.95	54.77
Apr-2025	96.31	1.1
May-2025	81.04	0
Jun-2025	96.77	0
Jul-2025	75.31	1.69
Aug-2025	76.16	0
Sep-2025	83.75	21.88
Oct-2025	100	0
Nov-2025	0	0
Dec-2025	29.45	47.06
Jan-2026	77.16	30.52
Feb-2026	56.72	44.39
Mar-2026	51.72	35.77



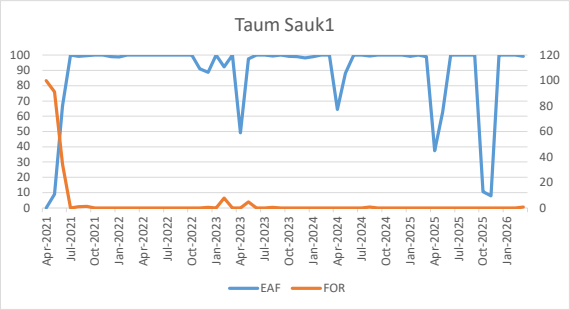
Sioux - Sioux 2

DATE	EAF	FOR
Apr-2021	0	0
May-2021	2.83	0
Jun-2021	94.53	5.63
Jul-2021	86.69	13.24
Aug-2021	99.29	0.68
Sep-2021	97.72	0
Oct-2021	95.76	0
Nov-2021	99.58	0
Dec-2021	66.16	0
Jan-2022	91.1	1.17
Feb-2022	99.42	0.85
Mar-2022	69.98	0
Apr-2022	97.33	3
May-2022	80.51	0
Jun-2022	87.07	0
Jul-2022	88.46	3.75
Aug-2022	99.99	0
Sep-2022	85.43	14.65
Oct-2022	75.57	27.88
Nov-2022	99.83	0
Dec-2022	87.11	0.32
Jan-2023	72.87	38.3
Feb-2023	98.94	0
Mar-2023	100	0
Apr-2023	68.25	13.94
May-2023	38.07	37
Jun-2023	100	0
Jul-2023	97.98	0
Aug-2023	99.7	0.26
Sep-2023	74.21	0
Oct-2023	89.35	10.76
Nov-2023	10.01	0
Dec-2023	43.39	50.69
Jan-2024	76.89	23.61
Feb-2024	69.05	0
Mar-2024	85.02	34.63
Apr-2024	70.96	0
May-2024	79.53	3.36
Jun-2024	99.26	0
Jul-2024	98.3	0
Aug-2024	96.74	0
Sep-2024	66.78	0
Oct-2024	79.75	0
Nov-2024	100	0
Dec-2024	82.12	18.48
Jan-2025	56.62	43.15
Feb-2025	81.81	11.67
Mar-2025	54.13	77.2
Apr-2025	68.61	33.02
May-2025	76.78	19.97
Jun-2025	95.16	0
Jul-2025	76.56	15.8
Aug-2025	94.16	0
Sep-2025	61.01	26.69
Oct-2025	73.65	27.21
Nov-2025	79.65	17.58
Dec-2025	94.37	0
Jan-2026	91.59	0
Feb-2026	45.01	58.19
Mar-2026	98.99	0



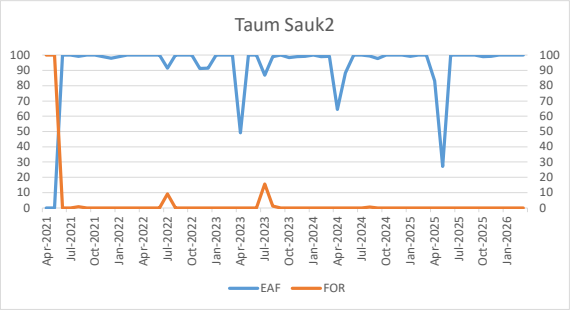
Taum Sauk - Taum Sauk 1

DATE	EAF	FOR
Apr-2021	0	100
May-2021	8.97	91.03
Jun-2021	66.66	34.39
Jul-2021	100	0
Aug-2021	99.13	0.97
Sep-2021	99.62	1.26
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	98.92	0
Jan-2022	98.79	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	99.99	0.02
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	90.97	0.02
Dec-2022	88.6	0.53
Jan-2023	100	0
Feb-2023	92.15	7.85
Mar-2023	100	0
Apr-2023	49.1	0
May-2023	97.46	4.8
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	99.46	0.61
Sep-2023	100	0
Oct-2023	99.06	0
Nov-2023	99.03	0
Dec-2023	98.19	0
Jan-2024	98.92	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	64.31	0
May-2024	88.21	0.03
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	99.33	0.67
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	99.99	0.01
Jan-2025	99.06	0
Feb-2025	100	0
Mar-2025	98.99	0
Apr-2025	37.5	0
May-2025	62.77	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	10.62	0
Nov-2025	7.91	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	99.27	0.73



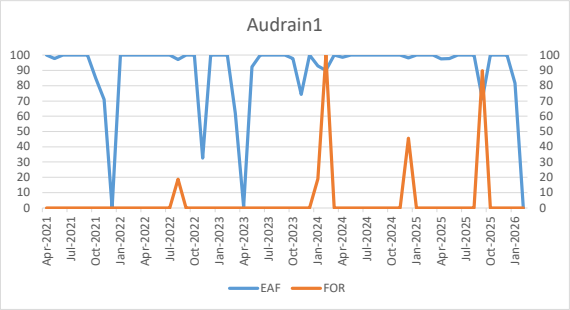
Taum Sauk - Taum Sauk 2

DATE	EAF	FOR
Apr-2021	0	100
May-2021	0	100
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	99.13	0.87
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	99.03	0
Dec-2021	97.98	0
Jan-2022	98.92	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	91.4	9.18
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	91.12	0
Dec-2022	91.4	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	49.1	0
May-2023	100	0.01
Jun-2023	100	0
Jul-2023	86.83	15.63
Aug-2023	98.92	1.16
Sep-2023	100	0
Oct-2023	98.25	0
Nov-2023	99.03	0
Dec-2023	99.13	0
Jan-2024	100	0
Feb-2024	98.85	0
Mar-2024	99.06	0
Apr-2024	64.31	0
May-2024	88.24	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	99.33	0.67
Sep-2024	97.74	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	99.99	0.01
Jan-2025	99.06	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	83.06	0
May-2025	27.15	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	98.99	0
Nov-2025	99.13	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



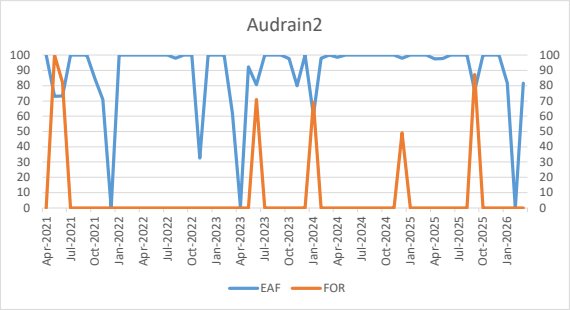
UE CTGs - Audrain CTG 1

DATE	EAF	FOR
Apr-2021	100	0
May-2021	97.72	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	84.81	0
Nov-2021	71.01	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	97.05	18.83
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	32.6	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.29	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	97.72	0
Nov-2023	74.35	0
Dec-2023	100	0
Jan-2024	92.98	18.98
Feb-2024	90.02	100
Mar-2024	100	0
Apr-2024	98.63	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	98.12	45.72
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	71.39	89.79
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



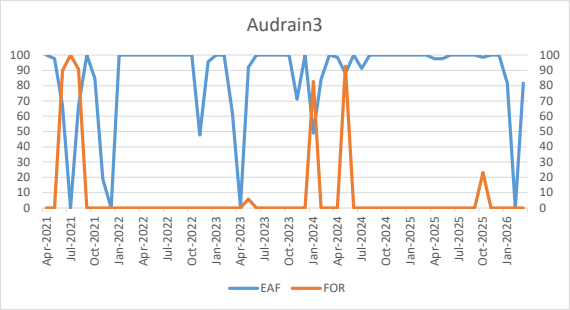
UE CTGs - Audrain CTG 2

DATE	EAF	FOR
Apr-2021	100	0
May-2021	72.98	100
Jun-2021	73.34	81.96
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	84.81	0
Nov-2021	71.01	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	97.85	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	32.6	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.29	0
Jun-2023	80.45	70.87
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	97.72	0
Nov-2023	79.89	0
Dec-2023	100	0
Jan-2024	60.72	68.94
Feb-2024	97.92	0
Mar-2024	100	0
Apr-2024	98.63	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	97.99	49.12
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	76.6	87.31
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



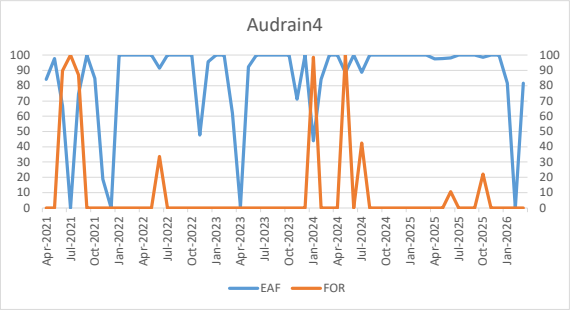
UE CTGs - Audrain CTG 3

DATE	EAF	FOR
Apr-2021	100	0
May-2021	97.72	0
Jun-2021	66.64	89.76
Jul-2021	0	100
Aug-2021	66.71	90.8
Sep-2021	100	0
Oct-2021	84.81	0
Nov-2021	18.73	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	47.71	0
Dec-2022	95.68	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.05	5.83
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	71.16	0
Dec-2023	100	0
Jan-2024	48.93	82.63
Feb-2024	84.12	0
Mar-2024	100	0
Apr-2024	98.63	0
May-2024	88.21	92.61
Jun-2024	100	0
Jul-2024	91.27	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	98.69	23.13
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



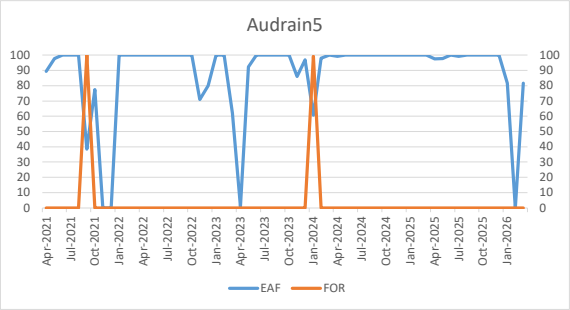
UE CTGs - Audrain CTG 4

DATE	EAF	FOR
Apr-2021	84.17	0
May-2021	97.72	0
Jun-2021	66.64	89.76
Jul-2021	0	100
Aug-2021	74.54	87.15
Sep-2021	100	0
Oct-2021	84.81	0
Nov-2021	18.72	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	91.46	33.69
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	47.71	0
Dec-2022	95.67	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.28	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	71.16	0
Dec-2023	100	0
Jan-2024	43.82	98.66
Feb-2024	84.12	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	88.52	100
Jun-2024	100	0
Jul-2024	88.75	42.47
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	98.02	10.62
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	98.69	22.21
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



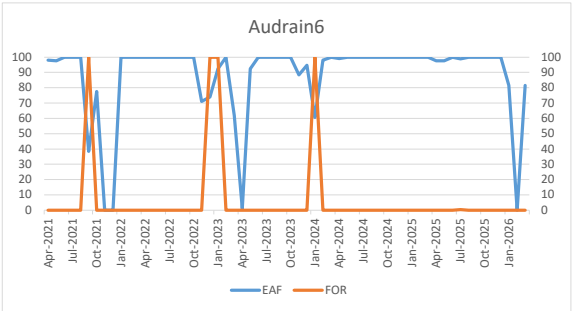
UE CTGs - Audrain CTG 5

DATE	EAF	FOR
Apr-2021	89.44	0
May-2021	97.72	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	38.42	100
Oct-2021	77.42	0
Nov-2021	0	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	71.01	0
Dec-2022	79.91	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.28	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	85.99	0
Dec-2023	96.91	0
Jan-2024	60.72	99.18
Feb-2024	97.92	0
Mar-2024	100	0
Apr-2024	99.13	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	99.2	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



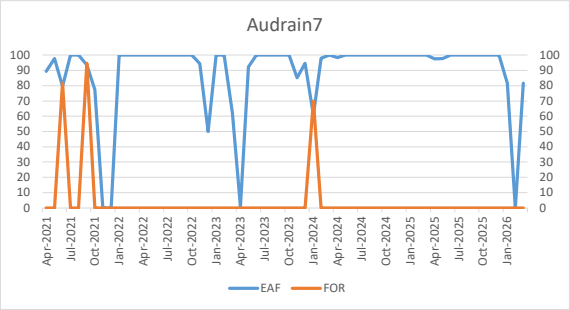
UE CTGs - Audrain CTG 6

DATE	EAF	FOR
Apr-2021	97.98	0
May-2021	97.72	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	38.42	100
Oct-2021	77.42	0
Nov-2021	0	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	71.01	0
Dec-2022	73.94	100
Jan-2023	92.37	100
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.28	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	88.35	0
Dec-2023	94.63	0
Jan-2024	60.71	100
Feb-2024	97.92	0
Mar-2024	100	0
Apr-2024	99.13	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	99.03	0.36
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



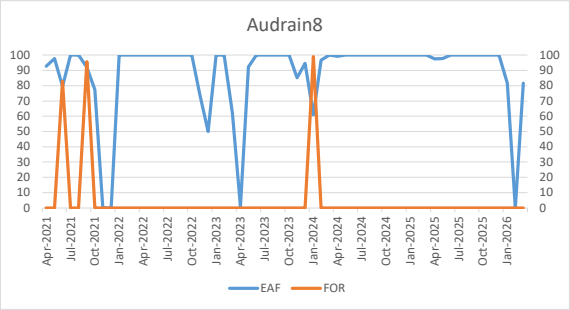
UE CTGs - Audrain CTG 7

DATE	EAF	FOR
Apr-2021	89.41	0
May-2021	97.72	0
Jun-2021	79.47	81.86
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	93.61	94.68
Oct-2021	77.42	0
Nov-2021	0	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	94.31	0
Dec-2022	50.13	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.28	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	85.03	0
Dec-2023	94.63	0
Jan-2024	60.72	69.92
Feb-2024	97.92	0
Mar-2024	100	0
Apr-2024	98.47	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



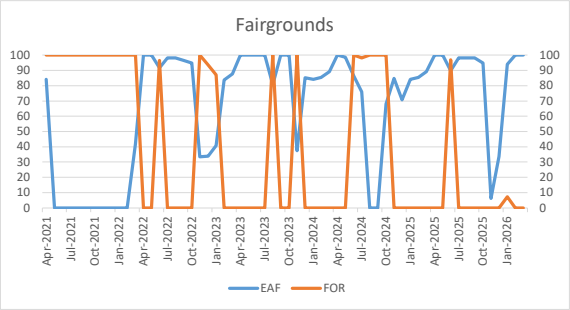
UE CTGs - Audrain CTG 8

DATE	EAF	FOR
Apr-2021	92.63	0
May-2021	97.72	0
Jun-2021	79.47	82.78
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	92.12	95.64
Oct-2021	77.42	0
Nov-2021	0	0
Dec-2021	0	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	74.34	0
Dec-2022	50.13	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	61.91	0
Apr-2023	0.96	0
May-2023	92.28	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	85.03	0
Dec-2023	94.63	0
Jan-2024	60.85	98.95
Feb-2024	96.7	0
Mar-2024	100	0
Apr-2024	99.13	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	97.64	0
May-2025	97.72	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	81.59	0
Feb-2026	0	0
Mar-2026	81.56	0



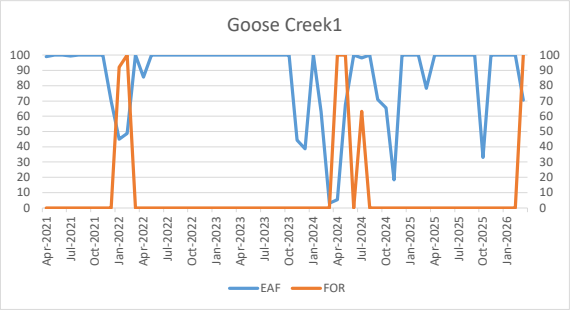
UE CTGs - Fairgrounds CTG 1

DATE	EAF	FOR
Apr-2021	84.17	100
May-2021	0	100
Jun-2021	0	100
Jul-2021	0	100
Aug-2021	0	100
Sep-2021	0	100
Oct-2021	0	100
Nov-2021	0	100
Dec-2021	0	100
Jan-2022	0	100
Feb-2022	0	100
Mar-2022	41.99	100
Apr-2022	100	0
May-2022	100	0
Jun-2022	91.68	96.44
Jul-2022	98.18	0
Aug-2022	98.18	0
Sep-2022	96.43	0
Oct-2022	94.74	0
Nov-2022	33.36	100
Dec-2022	33.83	93.55
Jan-2023	40.7	87.18
Feb-2023	83.82	0
Mar-2023	87.69	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	80.54	100
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	37.38	100
Dec-2023	85.07	0
Jan-2024	84.06	0
Feb-2024	85.29	0
Mar-2024	89.23	0
Apr-2024	100	0
May-2024	98.63	0
Jun-2024	86.46	100
Jul-2024	75.94	98.04
Aug-2024	0	100
Sep-2024	0	100
Oct-2024	68.04	100
Nov-2024	84.85	0
Dec-2024	70.77	0
Jan-2025	84.06	0
Feb-2025	85.29	0
Mar-2025	89.23	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	89.8	96.79
Jul-2025	98.18	0
Aug-2025	98.18	0
Sep-2025	98.18	0
Oct-2025	94.74	0
Nov-2025	6.35	0
Dec-2025	33.74	0
Jan-2026	93.93	7.24
Feb-2026	100	0
Mar-2026	100	0



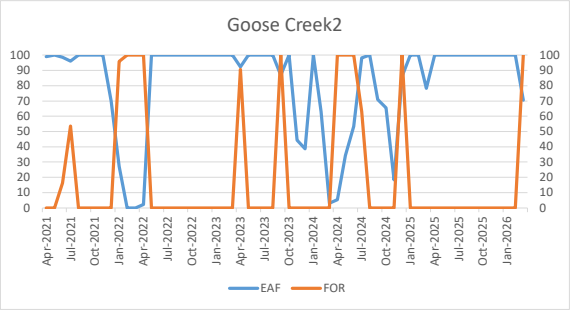
UE CTGs - Goose Creek CTG 1

DATE	EAF	FOR
Apr-2021	98.89	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	99.33	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	69.96	0
Jan-2022	45.02	91.98
Feb-2022	48.81	100
Mar-2022	100	0
Apr-2022	85.64	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	44.38	0
Dec-2023	38.85	0
Jan-2024	100	0
Feb-2024	63.07	0
Mar-2024	3.23	0
Apr-2024	5.42	100
May-2024	67.74	100
Jun-2024	100	0
Jul-2024	98.15	63.25
Aug-2024	100	0
Sep-2024	70.97	0
Oct-2024	65.46	0
Nov-2024	18.47	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	78.33	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	33.2	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	70.59	100



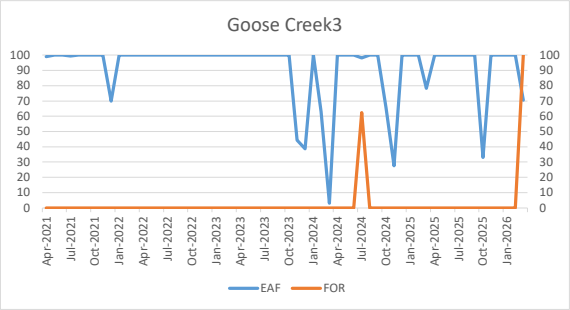
UE CTGs - Goose Creek CTG 2

DATE	EAF	FOR
Apr-2021	98.89	0
May-2021	100	0
Jun-2021	98.61	16.35
Jul-2021	96.11	53.51
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	69.96	0
Jan-2022	27.15	95.76
Feb-2022	0	100
Mar-2022	0	100
Apr-2022	2.22	100
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	92.16	90.64
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	86.81	100
Oct-2023	100	0
Nov-2023	44.38	0
Dec-2023	38.85	0
Jan-2024	100	0
Feb-2024	63.07	0
Mar-2024	3.23	0
Apr-2024	5.42	100
May-2024	34.28	100
Jun-2024	53.34	100
Jul-2024	98.15	62.99
Aug-2024	100	0
Sep-2024	70.97	0
Oct-2024	65.46	0
Nov-2024	18.47	0
Dec-2024	86.07	100
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	78.33	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	70.59	100



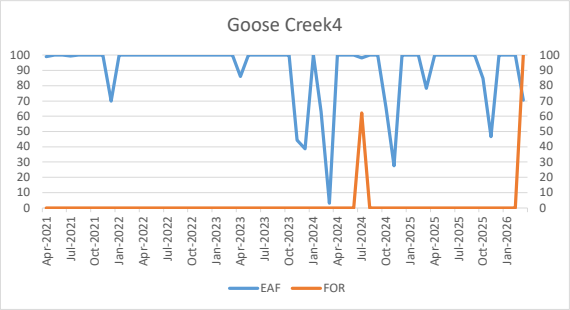
UE CTGs - Goose Creek CTG 3

DATE	EAF	FOR
Apr-2021	98.86	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	99.33	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	69.96	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	44.38	0
Dec-2023	38.85	0
Jan-2024	100	0
Feb-2024	63.07	0
Mar-2024	3.23	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	98.15	62.3
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	65.46	0
Nov-2024	27.6	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	78.33	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	33.2	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	70.59	100



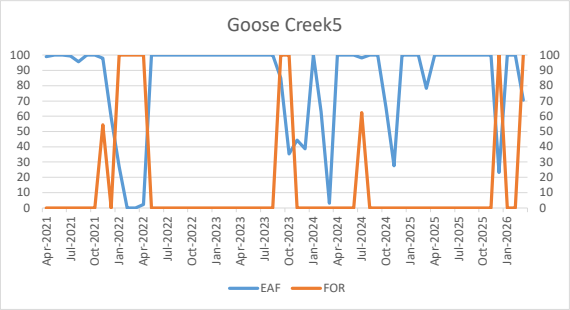
UE CTGs - Goose Creek CTG 4

DATE	EAF	FOR
Apr-2021	98.86	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	99.33	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	69.96	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	86.1	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	44.38	0
Dec-2023	38.85	0
Jan-2024	100	0
Feb-2024	63.07	0
Mar-2024	3.23	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	98.15	62.08
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	65.46	0
Nov-2024	27.6	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	78.33	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	84.81	0
Nov-2025	46.74	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	70.59	100



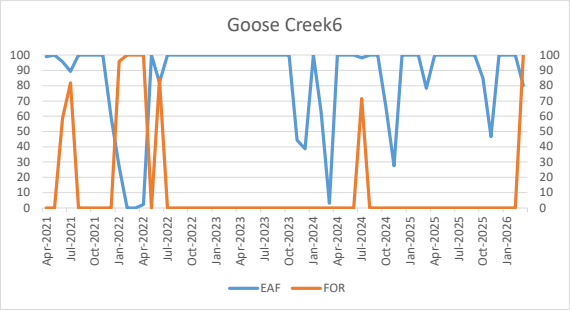
UE CTGs - Goose Creek CTG 5

DATE	EAF	FOR
Apr-2021	98.83	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	99.33	0
Aug-2021	95.67	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	97.95	54.29
Dec-2021	59.14	0
Jan-2022	26.98	100
Feb-2022	0	100
Mar-2022	0	100
Apr-2022	2.22	100
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	84.9	100
Oct-2023	35.49	100
Nov-2023	44.38	0
Dec-2023	38.85	0
Jan-2024	100	0
Feb-2024	63.07	0
Mar-2024	3.23	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	98.15	62.3
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	65.46	0
Nov-2024	27.6	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	78.33	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	23.25	100
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	70.59	100



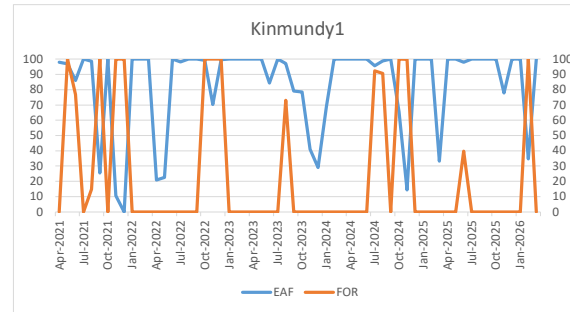
UE CTGs - Goose Creek CTG 6

DATE	EAF	FOR
Apr-2021	98.83	0
May-2021	100	0
Jun-2021	95.49	58.55
Jul-2021	89.43	81.8
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	59.14	0
Jan-2022	26.98	95.77
Feb-2022	0	100
Mar-2022	0	100
Apr-2022	2.22	100
May-2022	100	0
Jun-2022	82.08	84.22
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	44.38	0
Dec-2023	38.85	0
Jan-2024	100	0
Feb-2024	63.07	0
Mar-2024	3.23	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	98.17	71.5
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	65.46	0
Nov-2024	27.6	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	78.33	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	84.81	0
Nov-2025	46.74	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	80.28	100



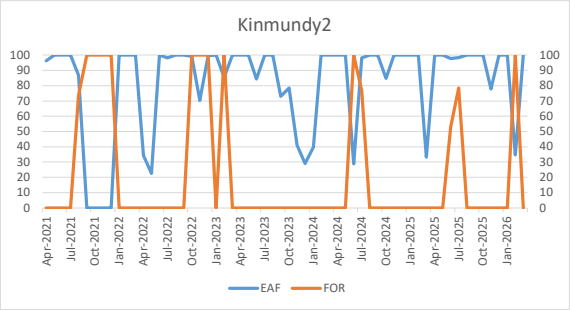
UE CTGs - Kinmundy CTG 1

DATE	EAF	FOR
Apr-2021	97.92	0
May-2021	96.88	100
Jun-2021	85.94	76.86
Jul-2021	100	0
Aug-2021	98.51	14.86
Sep-2021	25.5	100
Oct-2021	100	0
Nov-2021	10.68	100
Dec-2021	0	100
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	20.97	0
May-2022	22.58	0
Jun-2022	100	0
Jul-2022	98.12	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	99.19	100
Nov-2022	70.28	100
Dec-2022	99.6	100
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	84.31	0
Jul-2023	100	0
Aug-2023	97.21	73
Sep-2023	79.06	0
Oct-2023	78.34	0
Nov-2023	41.06	0
Dec-2023	29.17	0
Jan-2024	68.82	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	95.63	92.2
Aug-2024	98.81	90.64
Sep-2024	100	0
Oct-2024	65.46	100
Nov-2024	14.57	99.84
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	33.25	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	98	39.78
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	77.81	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	34.6	100
Mar-2026	100	0



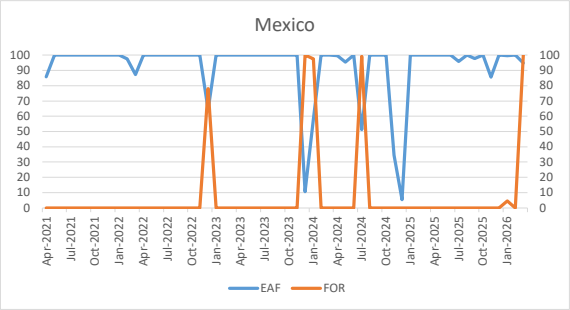
UE CTGs - Kinmundy CTG 2

DATE	EAF	FOR
Apr-2021	96.29	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	86.95	73.69
Sep-2021	0	100
Oct-2021	0	100
Nov-2021	0	100
Dec-2021	0	100
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	34.31	0
May-2022	22.58	0
Jun-2022	100	0
Jul-2022	98.12	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	99.19	100
Nov-2022	70.28	100
Dec-2022	99.6	100
Jan-2023	100	0
Feb-2023	85.34	100
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	84.31	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	72.99	0
Oct-2023	78.34	0
Nov-2023	41.06	0
Dec-2023	29.17	0
Jan-2024	39.79	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	28.8	100
Jul-2024	98.17	76.92
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	84.81	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	33.25	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	97.71	52.8
Jul-2025	98.45	78.44
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	77.81	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	34.6	100
Mar-2026	100	0



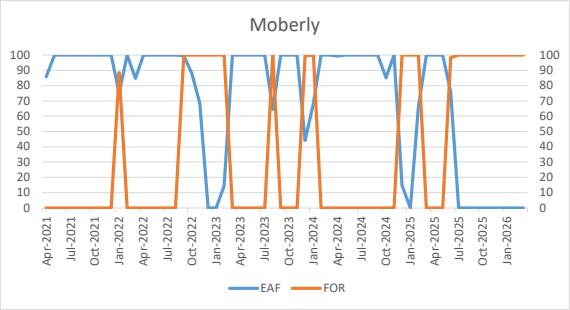
UE CTGs - Mexico CTG 1

DATE	EAF	FOR
Apr-2021	85.73	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	97.47	0
Mar-2022	87.22	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	64.22	78.1
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	10.62	100
Jan-2024	58.2	97.59
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	99.71	0
May-2024	95.46	0
Jun-2024	100	0
Jul-2024	51.27	99.18
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	34.4	0
Dec-2024	5.38	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	95.77	0
Aug-2025	100	0
Sep-2025	97.78	0
Oct-2025	100	0
Nov-2025	85.64	0
Dec-2025	100	0
Jan-2026	99.71	4.62
Feb-2026	100	0
Mar-2026	94.89	100



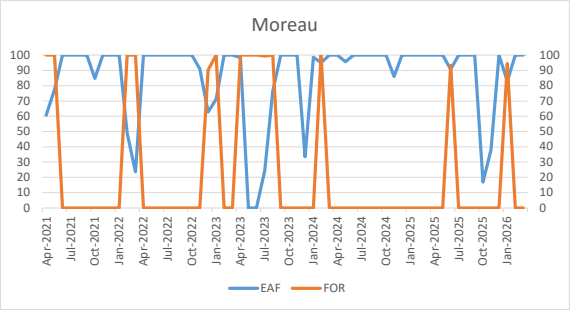
UE CTGs - Moberly CTG 1

DATE	EAF	FOR
Apr-2021	85.9	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	75.09	88.53
Feb-2022	100	0
Mar-2022	84.79	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	99.69	100
Oct-2022	88.17	100
Nov-2022	68.52	100
Dec-2022	0	100
Jan-2023	0	100
Feb-2023	14.44	100
Mar-2023	100	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	64.37	100
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	44.17	99.55
Jan-2024	68.15	100
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	99.45	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	85.2	0
Nov-2024	100	0
Dec-2024	14.78	100
Jan-2025	0	100
Feb-2025	65.93	100
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	75.97	98.3
Jul-2025	0	100
Aug-2025	0	100
Sep-2025	0	100
Oct-2025	0	100
Nov-2025	0	100
Dec-2025	0	100
Jan-2026	0	100
Feb-2026	0	100
Mar-2026	0	100



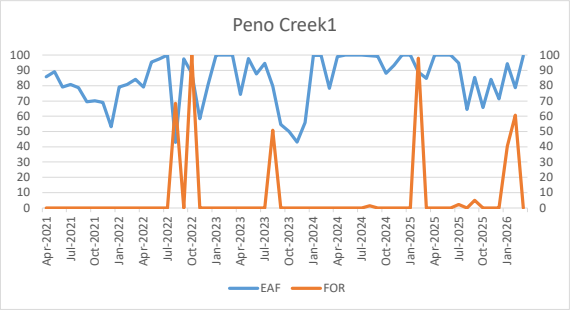
UE CTGs - Moreau CTG 1

DATE	EAF	FOR
Apr-2021	60.83	100
May-2021	77.42	100
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	84.81	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	49.03	100
Mar-2022	23.58	100
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	90.98	0
Dec-2022	62.87	90.17
Jan-2023	71.1	100
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	98.26	100
May-2023	0	100
Jun-2023	0	100
Jul-2023	24.37	99.44
Aug-2023	76.28	100
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	33.56	0
Jan-2024	98.55	0
Feb-2024	95.13	100
Mar-2024	100	0
Apr-2024	100	0
May-2024	95.63	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	86	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	90.72	93.26
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	17.07	0
Nov-2025	38.09	0
Dec-2025	100	0
Jan-2026	82.93	94.3
Feb-2026	100	0
Mar-2026	100	0



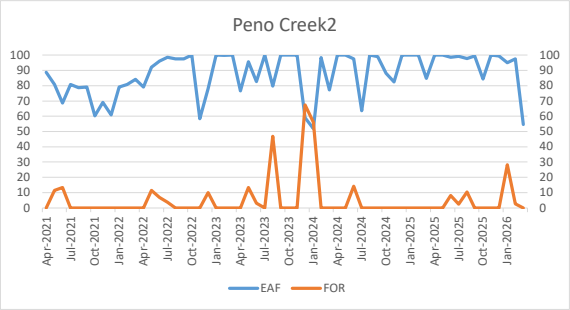
UE CTGs - Peno Creek CTG 1

DATE	EAF	FOR
Apr-2021	85.9	0
May-2021	89.06	0
Jun-2021	79.17	0
Jul-2021	80.85	0
Aug-2021	78.74	0
Sep-2021	69.38	0
Oct-2021	70.06	0
Nov-2021	69.09	0
Dec-2021	53.05	0
Jan-2022	79.25	0
Feb-2022	80.77	0
Mar-2022	84	0
Apr-2022	79.09	0
May-2022	95.45	0
Jun-2022	97.67	0
Jul-2022	100	0
Aug-2022	42.97	68.55
Sep-2022	97.67	0
Oct-2022	88.17	100
Nov-2022	58.37	0
Dec-2022	80.77	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	74.31	0
May-2023	97.7	0
Jun-2023	87.64	0
Jul-2023	94.49	0
Aug-2023	79.64	50.94
Sep-2023	54.68	0
Oct-2023	50	0
Nov-2023	43.14	0
Dec-2023	56	0
Jan-2024	99.94	0
Feb-2024	99.8	0
Mar-2024	78.33	0
Apr-2024	99.03	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	99.6	1.52
Sep-2024	99.26	0
Oct-2024	88.04	0
Nov-2024	93.19	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	88.99	97.9
Mar-2025	84.79	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	94.71	2.29
Aug-2025	64.47	0
Sep-2025	85.41	5.07
Oct-2025	65.57	0
Nov-2025	84	0
Dec-2025	71.29	0
Jan-2026	94.25	40.33
Feb-2026	78.57	60.78
Mar-2026	99.6	0



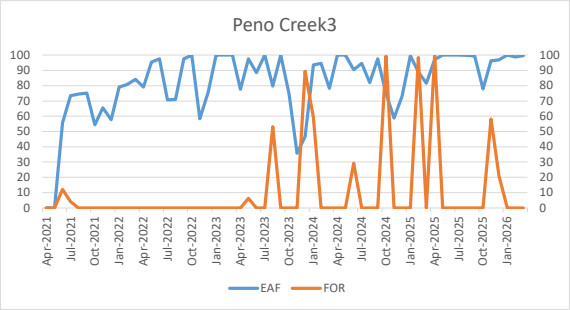
UE CTGs - Peno Creek CTG 2

DATE	EAF	FOR
Apr-2021	88.71	0
May-2021	80.72	11.51
Jun-2021	68.61	13.48
Jul-2021	80.85	0
Aug-2021	78.74	0
Sep-2021	79.17	0
Oct-2021	60.18	0
Nov-2021	69.09	0
Dec-2021	60.93	0
Jan-2022	79.25	0
Feb-2022	80.77	0
Mar-2022	84	0
Apr-2022	79.09	0
May-2022	92.11	11.49
Jun-2022	96.11	6.92
Jul-2022	98.66	3.84
Aug-2022	97.67	0
Sep-2022	97.67	0
Oct-2022	100	0
Nov-2022	58.37	0
Dec-2022	78.02	10.14
Jan-2023	100	0
Feb-2023	99.96	0
Mar-2023	100	0
Apr-2023	76.62	0
May-2023	95.69	13.37
Jun-2023	82.61	3.22
Jul-2023	100	0
Aug-2023	79.64	46.92
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	58.9	67.35
Jan-2024	51.94	56.08
Feb-2024	98.42	0
Mar-2024	77.09	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	97.64	14.12
Jul-2024	63.66	0
Aug-2024	100	0
Sep-2024	99.01	0
Oct-2024	88.02	0
Nov-2024	82.55	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	84.79	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	98.65	8.11
Jul-2025	99.13	2.49
Aug-2025	97.72	10.48
Sep-2025	99.45	0
Oct-2025	84.41	0
Nov-2025	100	0
Dec-2025	99.47	0
Jan-2026	94.95	28.32
Feb-2026	97.56	2.77
Mar-2026	54.51	0



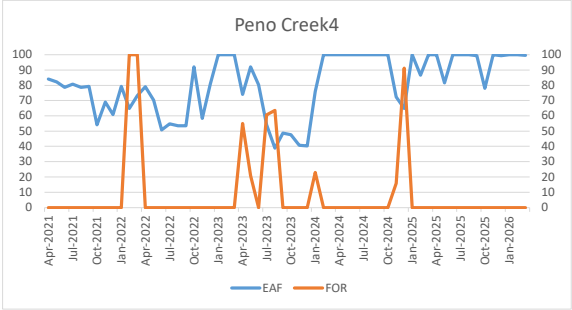
UE CTGs - Peno Creek CTG 3

DATE	EAF	FOR
Apr-2021	0	0
May-2021	0	0
Jun-2021	55.65	12.26
Jul-2021	73.48	4.2
Aug-2021	74.6	0
Sep-2021	75	0
Oct-2021	54.49	0
Nov-2021	65.45	0
Dec-2021	57.73	0
Jan-2022	79.25	0
Feb-2022	80.77	0
Mar-2022	84	0
Apr-2022	79.09	0
May-2022	95.45	0
Jun-2022	97.67	0
Jul-2022	70.7	0
Aug-2022	71.04	0
Sep-2022	97.67	0
Oct-2022	100	0
Nov-2022	58.37	0
Dec-2022	75.61	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	77.64	0
May-2023	97.61	6.19
Jun-2023	88.47	0
Jul-2023	100	0
Aug-2023	79.64	53.17
Sep-2023	100	0
Oct-2023	74.49	0
Nov-2023	35.74	0
Dec-2023	46.62	89.49
Jan-2024	93.51	59.18
Feb-2024	94.49	0
Mar-2024	78.33	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	90.38	29.4
Jul-2024	94.53	0
Aug-2024	81.92	0
Sep-2024	97.67	0
Oct-2024	74.99	99.37
Nov-2024	58.78	0
Dec-2024	72.98	0
Jan-2025	99.54	0
Feb-2025	88.99	98.34
Mar-2025	81.56	0
Apr-2025	97.12	100
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	99.87	0
Sep-2025	99.45	0
Oct-2025	77.96	0
Nov-2025	96.25	58.13
Dec-2025	96.78	20.97
Jan-2026	100	0
Feb-2026	98.81	0
Mar-2026	99.71	0



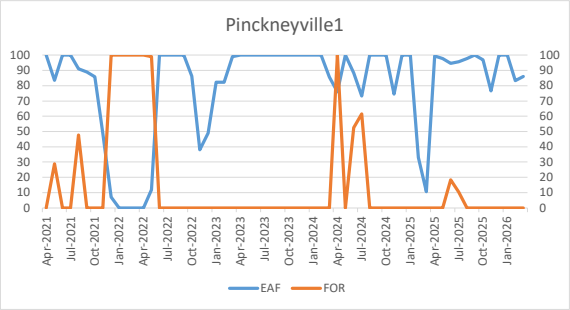
UE CTGs - Peno Creek CTG 4

DATE	EAF	FOR
Apr-2021	84.17	0
May-2021	82.29	0
Jun-2021	78.73	0
Jul-2021	80.85	0
Aug-2021	78.74	0
Sep-2021	79.17	0
Oct-2021	54.07	0
Nov-2021	69.09	0
Dec-2021	60.93	0
Jan-2022	79.25	0
Feb-2022	64.93	100
Mar-2022	73.26	100
Apr-2022	79.09	0
May-2022	70.37	0
Jun-2022	50.89	0
Jul-2022	54.76	0
Aug-2022	53.49	0
Sep-2022	53.49	0
Oct-2022	91.98	0
Nov-2022	58.37	0
Dec-2022	80.77	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	74.02	54.95
May-2023	92.06	20.8
Jun-2023	80.33	0
Jul-2023	54.25	60.7
Aug-2023	38.89	63.62
Sep-2023	48.84	0
Oct-2023	47.73	0
Nov-2023	40.72	0
Dec-2023	40.39	0
Jan-2024	75.92	23.03
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	72.24	15.91
Dec-2024	64.92	91.22
Jan-2025	100	0
Feb-2025	86.63	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	81.59	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	99.45	0
Oct-2025	77.96	0
Nov-2025	100	0
Dec-2025	99.47	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	99.71	0



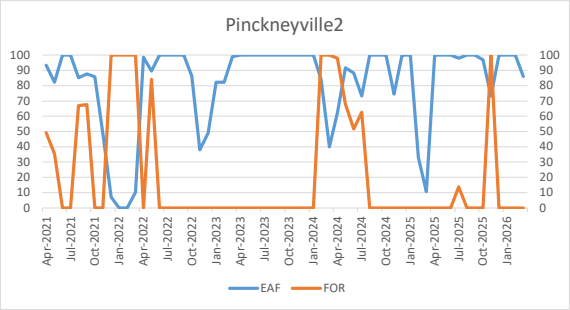
UE CTGs - Pinckneyville CTG 1

DATE	EAF	FOR
Apr-2021	100	0
May-2021	83.59	28.77
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	91.11	47.61
Sep-2021	89	0
Oct-2021	85.85	0
Nov-2021	48.74	0
Dec-2021	7.05	100
Jan-2022	0	100
Feb-2022	0	100
Mar-2022	0	100
Apr-2022	0	100
May-2022	11.86	98.97
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	86.23	0
Nov-2022	38.11	0
Dec-2022	48.89	0
Jan-2023	82.22	0
Feb-2023	82.22	0
Mar-2023	98.97	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	85.66	0
Apr-2024	75.99	100
May-2024	100	0
Jun-2024	88.26	52.59
Jul-2024	73.16	61.6
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	74.48	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	10.59	0
Apr-2025	99.29	0
May-2025	97.73	0
Jun-2025	94.64	18.3
Jul-2025	95.71	10.54
Aug-2025	97.73	0
Sep-2025	100	0
Oct-2025	96.77	0
Nov-2025	76.7	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	83.34	0
Mar-2026	86	0



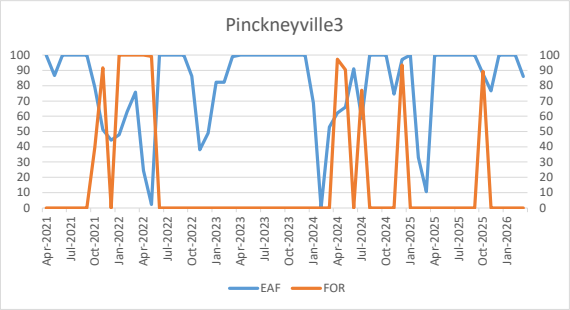
UE CTGs - Pinckneyville CTG 2

DATE	EAF	FOR
Apr-2021	93.23	49.24
May-2021	82.34	35.47
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	85.06	66.89
Sep-2021	87.65	67.61
Oct-2021	85.85	0
Nov-2021	48.74	0
Dec-2021	7.05	100
Jan-2022	0	100
Feb-2022	0	100
Mar-2022	10.31	100
Apr-2022	98.68	0
May-2022	89.59	84.16
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	86.23	0
Nov-2022	38.11	0
Dec-2022	48.89	0
Jan-2023	82.22	0
Feb-2023	82.22	0
Mar-2023	98.97	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	84.05	100
Mar-2024	39.97	100
Apr-2024	62.08	97.79
May-2024	91.8	68.04
Jun-2024	88.26	51.66
Jul-2024	73.16	62.46
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	74.48	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	10.59	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	97.8	13.86
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	96.77	0
Nov-2025	73.21	100
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	86.07	0



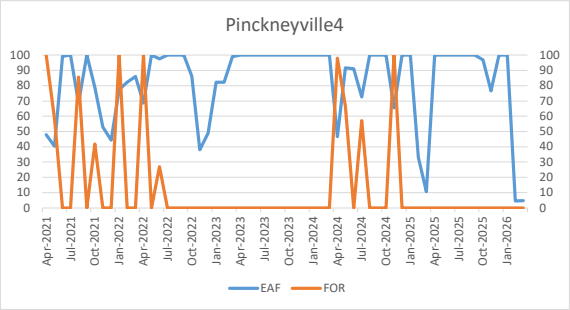
UE CTGs - Pinckneyville CTG 3

DATE	EAF	FOR
Apr-2021	100	0
May-2021	86.68	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	78.85	39.77
Nov-2021	51.22	91.75
Dec-2021	44.38	0
Jan-2022	47.87	100
Feb-2022	63.08	100
Mar-2022	75.74	100
Apr-2022	24.54	100
May-2022	2.19	99.24
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	86.23	0
Nov-2022	38.11	0
Dec-2022	48.89	0
Jan-2023	82.22	0
Feb-2023	82.22	0
Mar-2023	98.97	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	68.68	0
Feb-2024	0	0
Mar-2024	52.84	0
Apr-2024	62.08	97.44
May-2024	65.93	90.46
Jun-2024	90.97	0
Jul-2024	58.57	77.03
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	74.48	0
Dec-2024	97.1	93.49
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	10.59	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	87.65	89.46
Nov-2025	76.7	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	85.98	0



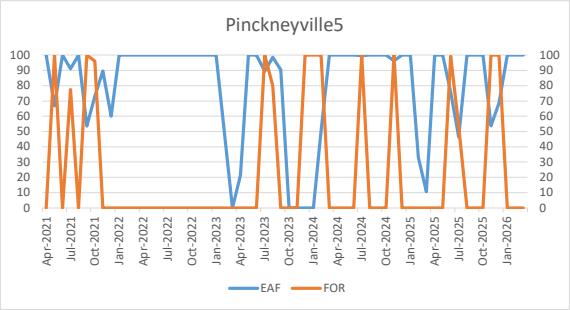
UE CTGs - Pinckneyville CTG 4

DATE	EAF	FOR
Apr-2021	47.92	100
May-2021	40.38	58.42
Jun-2021	99.2	0
Jul-2021	100	0
Aug-2021	68.63	85.68
Sep-2021	100	0
Oct-2021	78.85	41.77
Nov-2021	52.87	0
Dec-2021	44.38	0
Jan-2022	77.38	100
Feb-2022	82.22	0
Mar-2022	86.05	0
Apr-2022	68.64	100
May-2022	100	0
Jun-2022	97.67	26.89
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	86.23	0
Nov-2022	38.11	0
Dec-2022	48.89	0
Jan-2023	82.22	0
Feb-2023	82.22	0
Mar-2023	98.97	0
Apr-2023	100	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	46.66	97.88
May-2024	91.8	66.56
Jun-2024	90.97	0
Jul-2024	72.66	57.24
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	65.45	100
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	10.59	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	96.77	0
Nov-2025	76.7	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	4.61	0
Mar-2026	4.88	0



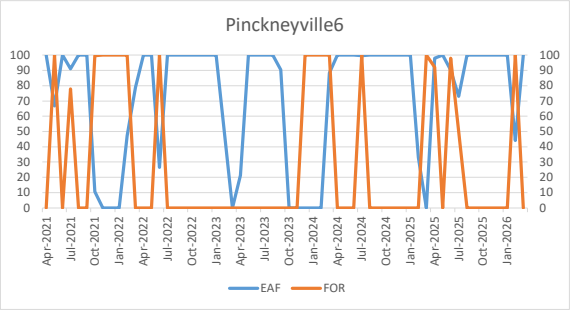
UE CTGs - Pinckneyville CTG 5

DATE	EAF	FOR
Apr-2021	100	0
May-2021	66.67	100
Jun-2021	100	0
Jul-2021	90.93	77.43
Aug-2021	100	0
Sep-2021	53.61	100
Oct-2021	72.98	96
Nov-2021	89.6	0
Dec-2021	60.12	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	51.04	0
Mar-2023	0	0
Apr-2023	21.47	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	89.34	100
Aug-2023	98.49	79.86
Sep-2023	90.37	0
Oct-2023	0	0
Nov-2023	0	0
Dec-2023	0	100
Jan-2024	0	100
Feb-2024	50.43	100
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	99.72	100
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	96.33	100
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	10.59	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	75.76	99.1
Jul-2025	46.37	53.63
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	53.81	100
Dec-2025	68.68	100
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



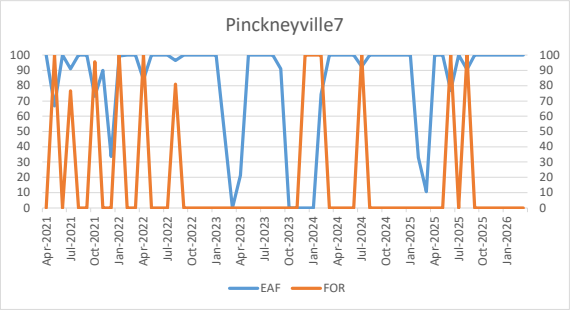
UE CTGs - Pinckneyville CTG 6

DATE	EAF	FOR
Apr-2021	100	0
May-2021	66.67	100
Jun-2021	100	0
Jul-2021	90.93	77.87
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	10.75	99.66
Nov-2021	0	100
Dec-2021	0	100
Jan-2022	0	100
Feb-2022	47.17	100
Mar-2022	78.94	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	26.47	100
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	51.04	0
Mar-2023	0	0
Apr-2023	21.47	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	90.37	0
Oct-2023	0	0
Nov-2023	0	0
Dec-2023	0	100
Jan-2024	0	100
Feb-2024	0	100
Mar-2024	88.27	100
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	99.72	100
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	0	100
Apr-2025	97.99	92.06
May-2025	100	0
Jun-2025	90.28	97.79
Jul-2025	73.12	50.12
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	44.2	100
Mar-2026	100	0



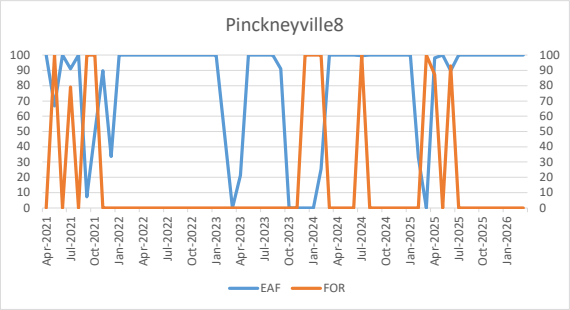
UE CTGs - Pinckneyville CTG 7

DATE	EAF	FOR
Apr-2021	100	0
May-2021	66.67	100
Jun-2021	100	0
Jul-2021	90.94	76.61
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	72.98	95.56
Nov-2021	89.94	0
Dec-2021	33.74	0
Jan-2022	99.33	100
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	83.94	100
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	96.46	81.04
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	51.04	0
Mar-2023	0	0
Apr-2023	21.46	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	90.97	0
Oct-2023	0	0
Nov-2023	0	0
Dec-2023	0	100
Jan-2024	0	100
Feb-2024	74.3	100
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	92.44	100
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	10.59	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	76.76	100
Jul-2025	100	0
Aug-2025	90.56	100
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



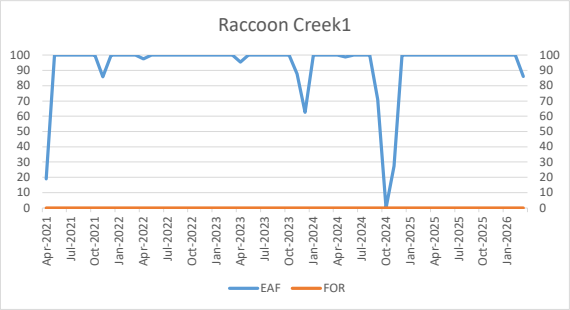
UE CTGs - Pinckneyville CTG 8

DATE	EAF	FOR
Apr-2021	100	0
May-2021	66.67	100
Jun-2021	100	0
Jul-2021	90.94	79.08
Aug-2021	100	0
Sep-2021	7.43	100
Oct-2021	49.31	100
Nov-2021	89.81	0
Dec-2021	33.74	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	51.04	0
Mar-2023	0	0
Apr-2023	21.46	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	90.97	0
Oct-2023	0	0
Nov-2023	0	0
Dec-2023	0	100
Jan-2024	0	100
Feb-2024	25.39	100
Mar-2024	100	0
Apr-2024	100	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	99.72	100
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	100	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	33.18	0
Mar-2025	0	100
Apr-2025	98.09	87.3
May-2025	100	0
Jun-2025	89.69	92.9
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



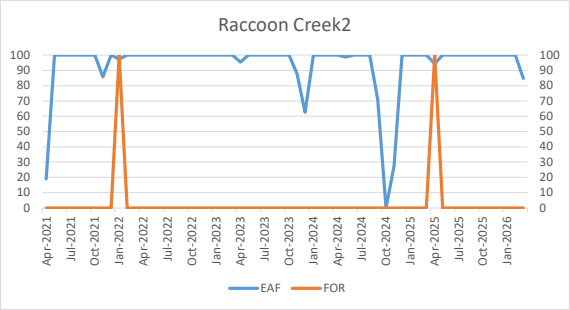
UE CTGs - Raccoon Creek CTG 1

DATE	EAF	FOR
Apr-2021	19.17	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	85.78	0
Dec-2021	100	0
Jan-2022	100	0
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	97.64	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	95.45	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	87.66	0
Dec-2023	62.52	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	98.79	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	70.97	0
Oct-2024	0	0
Nov-2024	27.46	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	85.97	0



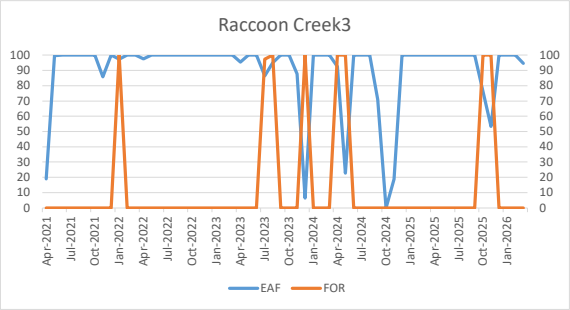
UE CTGs - Raccoon Creek CTG 2

DATE	EAF	FOR
Apr-2021	19.17	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	85.78	0
Dec-2021	100	0
Jan-2022	97.35	100
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	100	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	95.45	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	87.66	0
Dec-2023	62.51	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	100	0
May-2024	98.79	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	70.97	0
Oct-2024	0	0
Nov-2024	27.46	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	94.31	100
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	84.79	0



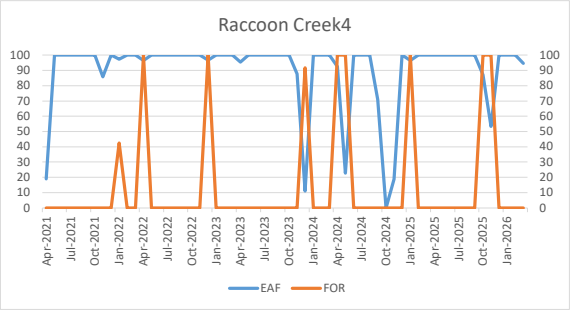
UE CTGs - Raccoon Creek CTG 3

DATE	EAF	FOR
Apr-2021	19.17	0
May-2021	99.61	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	85.78	0
Dec-2021	100	0
Jan-2022	97.35	100
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	97.64	0
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	95.45	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	86.31	97.37
Aug-2023	94.98	100
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	87.66	0
Dec-2023	6.59	100
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	92.57	100
May-2024	22.77	100
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	70.97	0
Oct-2024	0	0
Nov-2024	18.86	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	76.21	100
Nov-2025	53.4	100
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	94.48	0



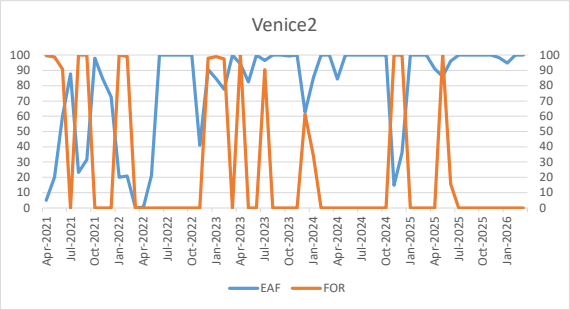
UE CTGs - Raccoon Creek CTG 4

DATE	EAF	FOR
Apr-2021	19.17	0
May-2021	100	0
Jun-2021	100	0
Jul-2021	100	0
Aug-2021	100	0
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	85.78	0
Dec-2021	100	0
Jan-2022	97.35	42.53
Feb-2022	100	0
Mar-2022	100	0
Apr-2022	96.5	100
May-2022	100	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	100	0
Dec-2022	96.69	100
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	95.45	0
May-2023	100	0
Jun-2023	100	0
Jul-2023	100	0
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	87.66	0
Dec-2023	11.2	91.76
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	92.57	100
May-2024	22.77	100
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	70.97	0
Oct-2024	0	0
Nov-2024	18.86	0
Dec-2024	100	0
Jan-2025	96.41	100
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	100	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	87.06	100
Nov-2025	53.4	100
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	94.48	0



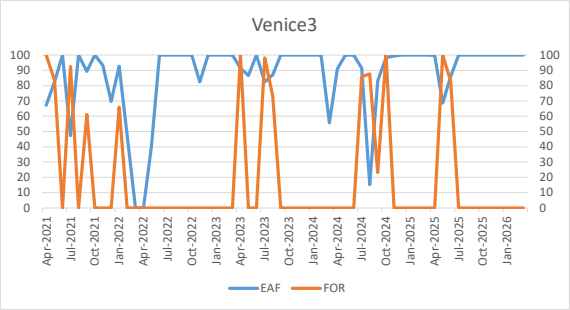
UE CTGs - Venice CTG 2

DATE	EAF	FOR
Apr-2021	5.07	99.61
May-2021	20.05	98.82
Jun-2021	60.1	90.8
Jul-2021	87.76	0
Aug-2021	23.3	100
Sep-2021	31.53	100
Oct-2021	97.89	0
Nov-2021	84.33	0
Dec-2021	72.55	0
Jan-2022	20.03	100
Feb-2022	20.98	99.26
Mar-2022	0	0
Apr-2022	0.63	0
May-2022	21.4	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	41.05	0
Dec-2022	90.62	97.87
Jan-2023	84.58	98.87
Feb-2023	77.68	97.51
Mar-2023	100	0
Apr-2023	94.17	100
May-2023	82.53	0
Jun-2023	100	0
Jul-2023	96.43	90.37
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	99.46	0
Nov-2023	100	0
Dec-2023	62.63	61.23
Jan-2024	85.22	34.05
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	84.31	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	14.82	100
Dec-2024	36.26	100
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	90.97	0
May-2025	86.11	100
Jun-2025	95.95	15.76
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	98.45	0
Jan-2026	94.89	0
Feb-2026	100	0
Mar-2026	100	0



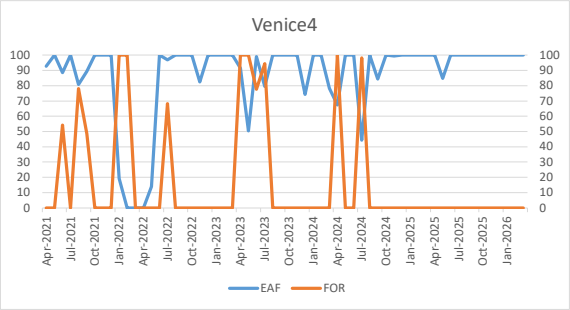
UE CTGs - Venice CTG 3

DATE	EAF	FOR
Apr-2021	67.22	100
May-2021	82.53	83.47
Jun-2021	100	0
Jul-2021	47.2	92.5
Aug-2021	100	0
Sep-2021	89.41	61.16
Oct-2021	100	0
Nov-2021	93.34	0
Dec-2021	69.63	0
Jan-2022	92.81	65.79
Feb-2022	47.47	0
Mar-2022	0	0
Apr-2022	0	0
May-2022	40.5	0
Jun-2022	100	0
Jul-2022	100	0
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	82.57	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	91.56	100
May-2023	86.7	0
Jun-2023	100	0
Jul-2023	82.47	98.12
Aug-2023	87.1	72.95
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	100	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	55.72	0
Apr-2024	90.98	0
May-2024	100	0
Jun-2024	100	0
Jul-2024	91.39	85.73
Aug-2024	15.15	87.68
Sep-2024	83.06	23.23
Oct-2024	98.25	100
Nov-2024	99.45	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	99.78	0
May-2025	68.63	100
Jun-2025	85.97	82.89
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



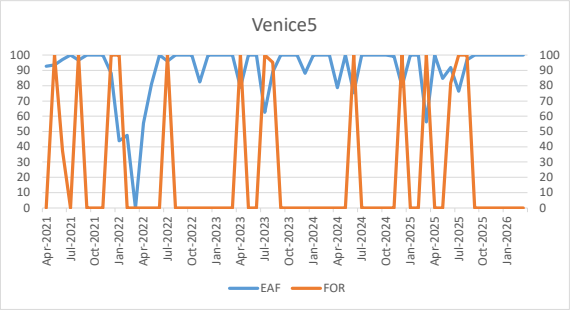
UE CTGs - Venice CTG 4

DATE	EAF	FOR
Apr-2021	92.75	0
May-2021	100	0
Jun-2021	88.5	54.18
Jul-2021	100	0
Aug-2021	80.83	77.99
Sep-2021	89.41	48.61
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	100	0
Jan-2022	19.22	100
Feb-2022	0	100
Mar-2022	0	0
Apr-2022	0	0
May-2022	14.02	0
Jun-2022	100	0
Jul-2022	96.8	68.26
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	82.57	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	91.56	100
May-2023	50.39	100
Jun-2023	98.99	77.68
Jul-2023	79.39	94.4
Aug-2023	100	0
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	74.24	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	78.33	0
Apr-2024	67.33	100
May-2024	100	0
Jun-2024	100	0
Jul-2024	44.49	98.12
Aug-2024	100	0
Sep-2024	84.31	0
Oct-2024	100	0
Nov-2024	99.45	0
Dec-2024	100	0
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	100	0
Apr-2025	100	0
May-2025	84.81	0
Jun-2025	100	0
Jul-2025	100	0
Aug-2025	100	0
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



UE CTGs - Venice CTG 5

DATE	EAF	FOR
Apr-2021	92.75	0
May-2021	93.47	100
Jun-2021	97.17	37.53
Jul-2021	100	0
Aug-2021	96.57	100
Sep-2021	100	0
Oct-2021	100	0
Nov-2021	100	0
Dec-2021	88.22	100
Jan-2022	43.98	100
Feb-2022	47.47	0
Mar-2022	0	0
Apr-2022	55.33	0
May-2022	80.92	0
Jun-2022	100	0
Jul-2022	96.03	100
Aug-2022	100	0
Sep-2022	100	0
Oct-2022	100	0
Nov-2022	82.57	0
Dec-2022	100	0
Jan-2023	100	0
Feb-2023	100	0
Mar-2023	100	0
Apr-2023	78.94	100
May-2023	100	0
Jun-2023	100	0
Jul-2023	62.6	100
Aug-2023	88.98	95.35
Sep-2023	100	0
Oct-2023	100	0
Nov-2023	100	0
Dec-2023	88.17	0
Jan-2024	100	0
Feb-2024	100	0
Mar-2024	100	0
Apr-2024	78.62	0
May-2024	100	0
Jun-2024	75.28	100
Jul-2024	100	0
Aug-2024	100	0
Sep-2024	100	0
Oct-2024	100	0
Nov-2024	99.28	0
Dec-2024	79.57	100
Jan-2025	100	0
Feb-2025	100	0
Mar-2025	56.26	100
Apr-2025	100	0
May-2025	84.81	0
Jun-2025	91.81	81.56
Jul-2025	76.34	100
Aug-2025	96.78	100
Sep-2025	100	0
Oct-2025	100	0
Nov-2025	100	0
Dec-2025	100	0
Jan-2026	100	0
Feb-2026	100	0
Mar-2026	100	0



# Attachment G

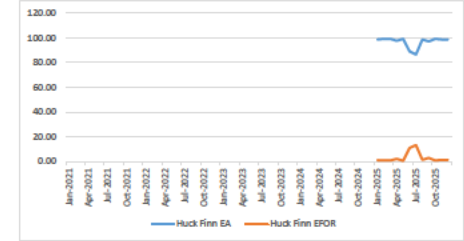
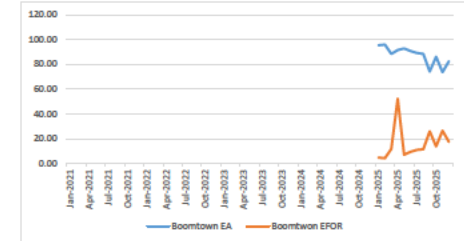
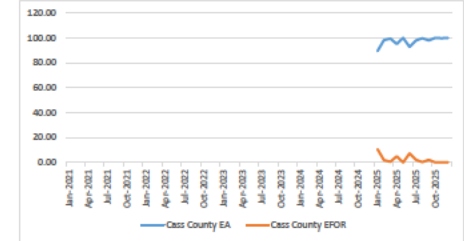
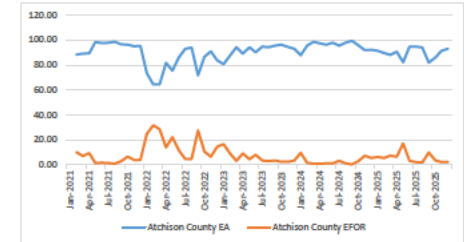
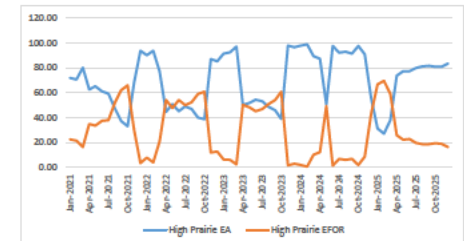
High Prairie		EA	EFOR
Jan-2021		71.98	22.51
Feb-2021		70.62	21.45
Mar-2021		80.14	16.46
Apr-2021		62.69	34.99
May-2021		65.25	33.63
Jun-2021		60.99	37.35
Jul-2021		59.32	37.94
Aug-2021		47.53	51.85
Sep-2021		37.26	62.06
Oct-2021		33.20	65.97
Nov-2021		67.91	30.53
Dec-2021		93.81	3.60
Jan-2022		90.12	7.86
Feb-2022		93.74	4.00
Mar-2022		76.92	21.01
Apr-2022		44.77	54.09
May-2022		50.69	47.85
Jun-2022		45.19	54.10
Jul-2022		49.13	50.23
Aug-2022		46.92	52.25
Sep-2022		40.05	59.17
Oct-2022		38.69	60.90
Nov-2022		87.03	11.93
Dec-2022		85.35	12.86
Jan-2023		91.48	6.46
Feb-2023		92.39	6.12
Mar-2023		96.98	2.56
Apr-2023		50.30	50.29
May-2023		51.81	48.18
Jun-2023		54.53	45.23
Jul-2023		53.02	46.94
Aug-2023		48.87	50.95
Sep-2023		45.97	54.19
Oct-2023		38.92	60.94
Nov-2023		97.73	1.66
Dec-2023		96.49	3.15
Jan-2024		97.80	2.08
Feb-2024		98.96	0.70
Mar-2024		89.42	10.29
Apr-2024		87.22	12.34
May-2024		50.68	49.23
Jun-2024		97.49	1.55
Jul-2024		92.24	6.86
Aug-2024		92.93	6.24
Sep-2024		91.46	6.96
Oct-2024		97.70	2.10
Nov-2024		90.79	8.69
Dec-2024		55.63	43.05
Jan-2025		31.14	66.76
Feb-2025		27.11	69.64
Mar-2025		37.97	59.18
Apr-2025		73.87	25.87
May-2025		77.40	22.33
Jun-2025		77.21	22.87
Jul-2025		79.85	19.77
Aug-2025		81.10	18.82
Sep-2025		81.70	18.73
Oct-2025		80.78	19.37
Nov-2025		80.92	19.05
Dec-2025		83.49	16.41

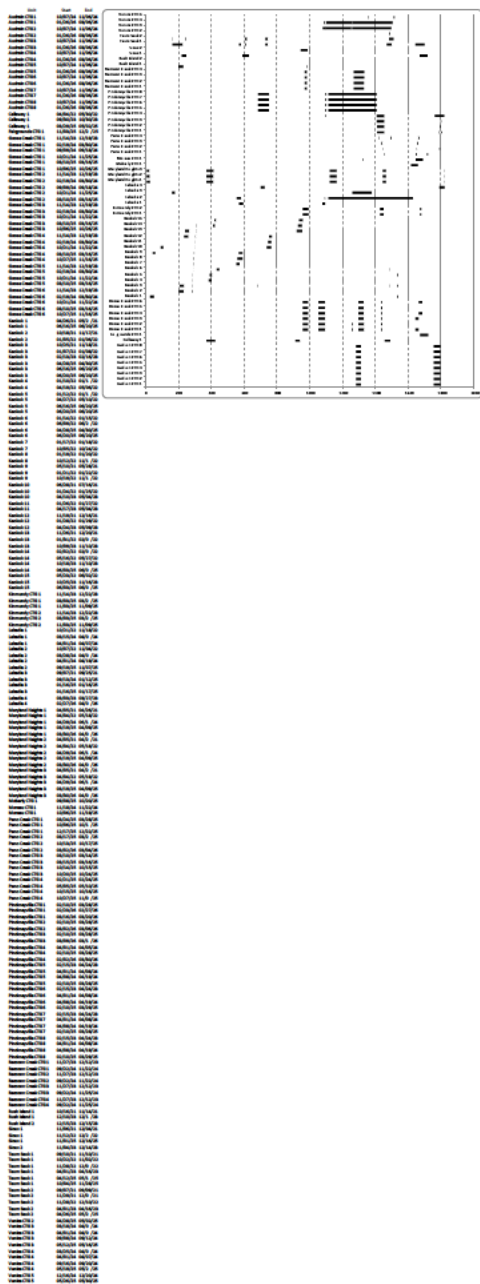
Atchison Cou		EA	EFOR
Jan-2021		88.35	10.05
Feb-2021		88.35	10.05
Mar-2021		89.08	6.97
Apr-2021		89.38	9.19
May-2021		98.33	1.23
Jun-2021		97.66	1.46
Jul-2021		97.79	1.29
Aug-2021		98.70	0.89
Sep-2021		96.57	2.92
Oct-2021		96.29	6.46
Nov-2021		95.02	3.80
Dec-2021		95.21	3.92
Jan-2022		73.33	24.71
Feb-2022		64.43	31.72
Mar-2022		64.46	28.65
Apr-2022		81.77	13.80
May-2022		75.42	22.14
Jun-2022		86.14	11.52
Jul-2022		93.15	4.67
Aug-2022		94.03	4.54
Sep-2022		71.56	27.37
Oct-2022		86.62	10.61
Nov-2022		90.96	6.43
Dec-2022		83.80	14.43
Jan-2023		80.74	16.36
Feb-2023		87.47	8.97
Mar-2023		94.34	3.14
Apr-2023		88.96	9.05
May-2023		94.32	4.29
Jun-2023		90.22	8.07
Jul-2023		94.61	3.27
Aug-2023		94.30	2.89
Sep-2023		95.38	3.42
Oct-2023		96.24	2.45
Nov-2023		94.53	2.36
Dec-2023		92.86	3.36
Jan-2024		87.77	9.65
Feb-2024		95.67	1.66
Mar-2024		98.78	0.65
Apr-2024		97.37	0.79
May-2024		96.31	0.95
Jun-2024		97.84	1.02
Jul-2024		95.62	3.02
Aug-2024		97.84	1.01
Sep-2024		99.33	0.34
Oct-2024		95.85	2.75
Nov-2024		91.95	7.20
Dec-2024		92.08	5.52
Jan-2025		91.45	6.24
Feb-2025		89.60	5.50
Mar-2025		87.97	7.15
Apr-2025		90.61	6.24
May-2025		82.21	16.95
Jun-2025		94.65	2.93
Jul-2025		94.69	2.03
Aug-2025		93.99	1.72
Sep-2025		81.88	9.82
Oct-2025		86.18	3.41
Nov-2025		91.28	2.06
Dec-2025		93.06	2.12

Cass County		EA	EFOR
Jan-2021			
Feb-2021			
Mar-2021			
Apr-2021			
May-2021			
Jun-2021			
Jul-2021			
Aug-2021			
Sep-2021			
Oct-2021			
Nov-2021			
Dec-2021			
Jan-2022			
Feb-2022			
Mar-2022			
Apr-2022			
May-2022			
Jun-2022			
Jul-2022			
Aug-2022			
Sep-2022			
Oct-2022			
Nov-2022			
Dec-2022			
Jan-2023			
Feb-2023			
Mar-2023			
Apr-2023			
May-2023			
Jun-2023			
Jul-2023			
Aug-2023			
Sep-2023			
Oct-2023			
Nov-2023			
Dec-2023			
Jan-2024			
Feb-2024			
Mar-2024			
Apr-2024			
May-2024			
Jun-2024			
Jul-2024			
Aug-2024			
Sep-2024			
Oct-2024			
Nov-2024			
Dec-2024			
Jan-2025		89.48	10.52
Feb-2025		98.17	1.83
Mar-2025		99.39	0.61
Apr-2025		95.04	4.96
May-2025		99.99	0.01
Jun-2025		92.74	7.26
Jul-2025		97.83	2.17
Aug-2025		99.72	0.28
Sep-2025		97.79	2.21
Oct-2025		99.93	0.04
Nov-2025		99.78	0.22
Dec-2025		99.90	0.10

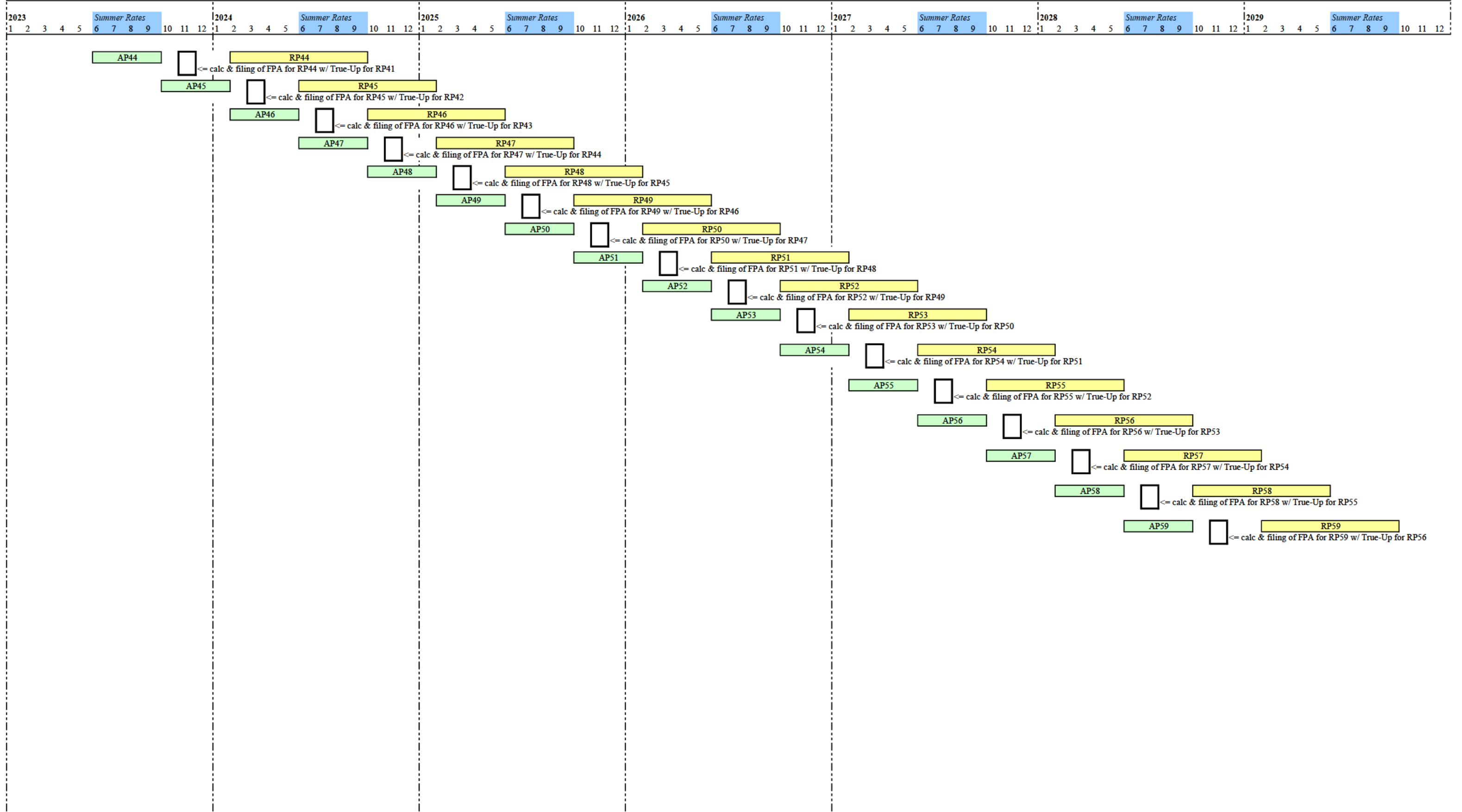
Boomtown		EA	EFOR
Jan-2021			
Feb-2021			
Mar-2021			
Apr-2021			
May-2021			
Jun-2021			
Jul-2021			
Aug-2021			
Sep-2021			
Oct-2021			
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Sep-2024			
Oct-2024			
Nov-2024			
Dec-2024			
Jan-2025		95.32	4.68
Feb-2025		95.87	4.13
Mar-2025		88.41	11.59
Apr-2025		91.61	52.27
May-2025		92.89	7.11
Jun-2025		90.70	9.30
Jul-2025		89.04	10.96
Aug-2025		88.54	11.46
Sep-2025		74.08	25.92
Oct-2025		86.11	13.89
Nov-2025		73.63	26.37
Dec-2025		82.57	17.43

Huck Finn		EA	EFOR
Jan-2021			
Feb-2021			
Mar-2021			
Apr-2021			
May-2021			
Jun-2021			
Jul-2021			
Aug-2021			
Sep-2021			
Oct-2021			
Nov-2021			
Dec-2021			
Jan-2022			
Feb-2022			
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Sep-2024			
Oct-2024			
Nov-2024			
Dec-2024			
Jan-2025		98.82	1.18
Feb-2025		99.16	0.84
Mar-2025		99.16	0.84
Apr-2025		97.69	2.31
May-2025		99.28	0.72
Jun-2025		89.07	10.93
Jul-2025		86.59	13.41
Aug-2025		98.74	1.26
Sep-2025		97.16	2.84
Oct-2025		99.23	0.77
Nov-2025		98.64	1.36
Dec-2025		98.67	1.33





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



**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72

APPLYING TO

**MISSOURI SERVICE AREA**

**RIDER FAC**

**FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE**

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

**APPLICABILITY**

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), ~~and 11(M)~~, and 14(M).

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

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

<u>Accumulation Period (AP)</u>	<u>Recovery Period (RP)</u>
February through May	October through May
June through September	February through September
October through January	June through January

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

RP means the calendar months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage. Notwithstanding that each RP covers a period of eight months, when an extraordinary event has occurred that results in an increase to actual net energy costs in an accumulation period, for good cause shown, subject to Commission approval after an opportunity for any party to be heard, the Company shall defer recovery beyond eight months over a period determined by the Commission upon a finding that the magnitude of the increase on customers of recovering the difference between actual net energy costs and net base energy costs for that accumulation period should be mitigated. The difference not recovered within the eight-month recovery period applicable to the accumulation period at issue will be added to subsequent recovery periods until recovered with a true-up at the end of the Commission approved extended recovery period.

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

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DATE EFFECTIVE June 1, 2025

ISSUED BY Mark C. Birk  
NAME OF OFFICER

Chairman & President  
TITLE

St. Louis, Missouri  
ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 3rd Revised SHEET NO. 72.1

CANCELLING MO.P.S.C. SCHEDULE NO. 6 2nd Revised SHEET NO. 72.1

APPLYING TO MISSOURI SERVICE AREA

**RIDER FAC**

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

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

**FAR DETERMINATION**

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

For each FAR filing made, the FAR<sub>RP</sub> is calculated as:

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

Where:

$$ANEC = FC + PP + E \pm R - OSSR$$

FC = Fuel costs and revenues associated with the Company's in-service generating plants, but excluding decommissioning and retirement costs, consisting of the following:

- 1) For fossil fuel plants:
  - A. the following costs and revenues (including applicable taxes) arising from steam plant operations recorded in FERC Account 501: coal commodity, gas, alternative fuels, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, fuel additive costs included in commodity or transportation costs, oil costs, ash disposal costs and revenues, and expenses resulting from fuel and transportation portfolio optimization activities;
  - B. the following costs and revenues reflected in FERC Account 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone, and powder activated carbon; and
  - C. the following costs and revenues (including applicable taxes) arising from non-steam plant operations recorded in FERC Account 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities, but excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center; and
- 2) The following costs and revenues (including applicable taxes) arising from nuclear plant operations, recorded in FERC Account 518: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

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ISSUED BY Mark C. Birk Chairman & President St. Louis, Missouri  
NAME OF OFFICER TITLE ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 3rd Revised SHEET NO. 72.2

CANCELLING MO.P.S.C. SCHEDULE NO. 6 2nd Revised SHEET NO. 72.2

APPLYING TO MISSOURI SERVICE AREA

**RIDER FAC**

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

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

**FAR DETERMINATION (Cont'd.)**

- PP = Purchased power costs and revenues and consists of the following:
  - 1) The following costs and revenues for purchased power reflected in FERC Account 555, excluding (a) all charges under Midcontinent Independent System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and (b) generation capacity charges for contracts with terms in excess of one (1) year. Such costs and revenues include:
    - A. MISO costs or revenues for MISO's energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:
      - i. Energy;
      - ii. Losses;
      - iii. Congestion management:
        - a. Congestion;
        - b. Financial Transmission Rights; and
        - c. Auction Revenue Rights;
      - iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;
      - v. Revenue sufficiency guarantees;
      - vi. Revenue neutrality uplift;
      - vii. Net inadvertent energy distribution amounts;
      - viii. Ancillary Services:
        - a. Regulating reserve service (MISO Schedule 3, or its successor);
        - b. Energy imbalance service (MISO Schedule 4, or its successor);
        - c. Spinning reserve service (MISO Schedule 5, or its successor);
        - d. Supplemental reserve service (MISO Schedule 6, or its successor); and
        - e. Short-term reserve service;
      - ix. Demand response:
        - a. Demand response allocation uplift; and
        - b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);
      - x. System Support Resource:
        - a. MISO Schedule 43K.

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ISSUED BY Mark C. Birk Chairman & President St. Louis, Missouri  
NAME OF OFFICER TITLE ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.3

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.3

APPLYING TO

**MISSOURI SERVICE AREA**

**RIDER FAC**

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

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

**FAR DETERMINATION (Cont'd.)**

B. Non-MISO costs or revenues as follows:

- i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;
- ii. If not received from a centrally administered market:
  - a. Costs for purchases of energy; and
  - b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

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

- 2) ~~Nine and 22/100~~~~Ten and 73/100~~ percent (~~9.22~~~~10.73~~%) of transmission service costs reflected in FERC Account 565 and ~~Nine and 22/100~~~~ten and 73/100~~ percent (~~10~~~~9.22~~~~73~~%) of transmission revenues reflected in FERC Account 456.1 (excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule). Such transmission service costs and revenues included in Factor PP include:

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NAME OF OFFICER

Chairman & President  
TITLE

St. Louis, Missouri  
ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.4

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.4

APPLYING TO MISSOURI SERVICE AREA

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Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2024-0319.

DATE OF ISSUE May 2, 2025

DATE EFFECTIVE June 1, 2025

ISSUED BY Mark C. Birk  
NAME OF OFFICER

Chairman & President  
TITLE

St. Louis, Missouri  
ADDRESS

**Schedule AMM-D3**

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.5

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.5

APPLYING TO MISSOURI SERVICE AREA

**RIDER FAC**

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

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

**FAR DETERMINATION (Cont'd.)**

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

- E = Costs and revenues for SO<sub>2</sub> and NO<sub>x</sub> emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.
- R = Net insurance recoveries for costs/revenues included in this Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included in this Rider FAC.

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DATE OF ISSUE May 2, 2025 DATE EFFECTIVE June 1, 2025

ISSUED BY Mark C. Birk Chairman & President St. Louis, Missouri

NAME OF OFFICER TITLE ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 3rd Revised SHEET NO. 72.6

CANCELLING MO.P.S.C. SCHEDULE NO. 6 2nd Revised SHEET NO. 72.6

APPLYING TO MISSOURI SERVICE AREA

**RIDER FAC**

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

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

**FAR DETERMINATION (Cont'd.)**

OSSR = Costs and revenues in FERC Account 447 for:

- 1. Capacity;
- 2. Energy;
- 3. Ancillary services, including:
  - A. Regulating reserve service (MISO Schedule 3, or its successor);
  - B. Energy Imbalance Service (MISO Schedule 4, or its successor);
  - C. Spinning reserve service (MISO Schedule 5, or its successor); and
  - D. Supplemental reserve service (MISO Schedule 6, or its successor);
  - E. Ramp capability service; and
  - F. Short-term reserve service;
- 4. Make-whole payments, including:
  - A. Price volatility; and
  - B. Revenue sufficiency guarantee;
- 5. Hedging; and
- 6. System Support Resource:
  - A. MISO Schedule 43K.

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

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Community Solar Program resource allocated to shareholders under the approved stipulation in File No. ER-2021-0240.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors FC, PP and OSSR shall not include costs and revenues for (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (b) amounts associated with generation assets dedicated, as of the date BF was

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Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2024-0319.

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ISSUED BY Mark C. Birk Chairman & President St. Louis, Missouri  
NAME OF OFFICER TITLE ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.7

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.7

APPLYING TO MISSOURI SERVICE AREA

**RIDER FAC**

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

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

**FAR DETERMINATION (Cont'd.)**

determined, to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (c) amounts associated with generation assets that began commercial operation after the date BF was determined and that were dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factors FC, PP, and OSSR when it began commercial operation, (d) for Renewable Energy Standard compliance included in Rider RESRAM, (e) amounts associated with energy purchased from the MISO market to serve digital currency mining by the Company, (f) amounts related to wholesale capacity sold as part of the Company's mitigation of a Large Load Customer's Exit Fee or Capacity Reduction Fee as part of the Company's mitigation provided for in Sections 12 and 13, respectively, of Service Classification No. 14(M), or amounts paid by a large load customer for interim capacity acquired by the Company pursuant to the interim capacity provisions of Service Classification 14(M), which amounts shall include the impacts of the net settlement of the purchased, or any customer-provided, interim capacity volumes and the planning reserve margin requirement associated with the large load customer that was satisfied, and (g) those amounts specified by Commission Order approving any tariff, rider or program, to be excluded from Rider FAC. Moreover, if a research and development ("R&D") project would impact the amounts for Factors FC, PP, or OSSR in an upcoming FAR filing, the Company shall file, in the docket in which this Rider FAC was approved, a notice outlining what the research and development project consists of, and how it will impact such factors in the upcoming FAR filing. The Company will bear the burden of proof to show that the impacts of the subject project should be included in Factors FC, PP, or OSSR, as the case may be. Such notice shall be filed no fewer than 60 days prior to the date of the subject FAR filing. Parties shall have thirty days after the filing of the notice to challenge the inclusion of the impacts of such project on such Factors in the determination of the FAR by stating the reasons for the challenge. If a party challenges the inclusion of a cost/revenue, the costs/revenue will be removed from the FAR until the Commission makes a determination regarding the inclusion of the cost/revenue. If the Commission orders a challenged cost be included in the FAC, the costs will be refunded or the revenues returned along with interest in the next periodic adjustment. For purposes of this Rider FAC, a "research and development project" is defined the same as "Research, Development, and Demonstration (RD&D)" as defined in 18 CFR Chapter 1, subchapter C, Part 101, Federal Power Act Definition 32.B, provided that if the project at issue consumes electricity only incidentally, it will not constitute a research and development project.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall

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NAME OF OFFICER

Chairman & President  
TITLE

St. Louis, Missouri  
ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.8

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.8

APPLYING TO

**MISSOURI SERVICE AREA**

nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

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Chairman & President  
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St. Louis, Missouri  
ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.9

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.9

APPLYING TO

**MISSOURI SERVICE AREA**

RIDER FAC

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

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

FAR DETERMINATION (Cont'd.)

B = BF x S<sub>AP</sub>

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BFSUMMER) is \$0.01~~600424~~ per kWh. The BF applicable to October through May calendar months (BFWINTER) is \$0.013~~7583~~ per kWh.

S<sub>AP</sub> = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node), but excluding kWh for research and development projects, the impact of which are challenged or ordered to be excluded by the Commission, plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

S<sub>RP</sub> = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) but excluding kWh for research and development projects, the impact of which are challenged or ordered to be excluded by the Commission, plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

I = Interest applicable to

- (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered;
- (ii) refunds due to prudence reviews ("P"), if any; and
- (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("TUP") provided for herein.

Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2024-0319.

DATE OF ISSUE May 2, 2025

DATE EFFECTIVE June 1, 2025

ISSUED BY Mark C. Birk  
NAME OF OFFICER

Chairman & President  
TITLE

St. Louis, Missouri  
ADDRESS

**Schedule AMM-D3**

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

3rd Revised

SHEET NO. 72.10

CANCELLING MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.10

APPLYING TO MISSOURI SERVICE AREA

**RIDER FAC**

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

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

**FAR DETERMINATION (Cont'd.)**

Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

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

TUP = True-up amount as defined below.

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

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

where:

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

FAR<sub>RP</sub> = FAR Recovery Period rate component calculated to recover under- or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

FAR<sub>(RP-1)</sub> = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR<sub>RP</sub>.

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

Secondary Voltage Service (VAF <sub>SEC</sub> )	1.0560
Primary Voltage Service (VAF <sub>PRI</sub> )	1.0240
High Voltage Service (VAF <sub>HV</sub> )	1.0060
Transmission Voltage Service (VAF <sub>TRANS</sub> )	0.9931

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

**TRUE-UP**

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

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

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

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DATE OF ISSUE May 2, 2025 DATE EFFECTIVE June 1, 2025  
ISSUED BY Mark C. Birk Chairman & President St. Louis, Missouri  
NAME OF OFFICER TITLE ADDRESS

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

8th Revised

SHEET NO. 72.11

CANCELLING MO.P.S.C. SCHEDULE NO. 6

11th Revised

SHEET NO. 72.9

APPLYING TO

**MISSOURI SERVICE AREA**

**RIDER FAC**

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

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

**GENERAL RATE CASE/PRUDENCE REVIEWS**

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

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

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

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ISSUED BY Mark C. Birk  
NAME OF OFFICER

Chairman & President  
TITLE

St. Louis, Missouri  
ADDRESS

UNION ELECTRIC COMPANY

ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6

Original SHEET NO. 72.12

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

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

**FAC CHARGE TYPE TABLE**

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

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

DA Asset Energy Amount;	RT Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;	RT Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;	RT Contingency Reserve Deployment Failure Charge Amount;
DA Financial Bilateral Transaction Congestion Amount;	RT Demand Response Allocation Uplift Charge;
DA Financial Bilateral Transaction Loss Amount;	RT Distribution of Losses Amount;
DA Loss Rebate on Carve-out GFA;	RT Excessive Energy Amount;
DA Loss Rebate on Option B GFA;	RT Excessive\Deficient Energy Deployment Charge Amount;
DA Non-Asset Energy Amount;	RT Financial Bilateral Transaction Congestion Amount;
DA Ramp Capability Amount;	RT Financial Bilateral Transaction Loss Amount;
DA Regulation Amount;	RT Loss Rebate on Carve-out GFA;
DA Revenue Sufficiency Guarantee Distribution Amount;	RT Miscellaneous Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;	RT Ramp Capability Amount;
DA Short-term Reserve Amount;	RT Real-Time MVP Distribution;
DA Spinning Reserve Amount;	RT Net
DA Supplemental Reserve Amount;	RT Net
DA Virtual Energy Amount; <del>DA Uncertainty Reserve Amount;</del>	
FTR Annual Transaction Amount; <del>DA Uncertainty Reserve Distribution Amount;</del>	
Inadvertent Distribution Amount; FTR ARR Transaction Amount; <del>DA Virtual Energy Amount;</del>	
Regulation Adjustment Amount;	
FTR ARR Stage 2 Distribution;	RT Non-Asset Energy Amount;
FTR Full Funding Guarantee Amount;	RT Non-Excessive Energy Amount;
FTR Guarantee Uplift Amount;	RT Price Volatility Make Whole Payment;
FTR Hourly Allocation Amount;	RT Regulation Amount;
FTR ARR Infeasible Uplift Amount;	RT Regulation Cost Distribution Amount;
FTR Monthly Allocation Amount;	RT Resource Adequacy Auction Amount;
FTR Monthly Transaction Amount;	RT Revenue Neutrality Uplift Amount;
FTR Yearly Allocation Amount;	RT Revenue Sufficiency Guarantee First Pass Dist Amount;
FTR Transaction Amount;	RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
	RT Schedule 49 Distribution;
	RT Short-term Reserve Amount;
	RT Spinning Reserve Amount;
	RT Spinning Reserve Cost Distribution Amount;
	RT Supplemental Reserve Amount;
	RT Supplemental Reserve Cost Distribution Amount;
	<del>RT Uncertainty Reserve Amount;</del>
	<del>RT Uncertainty Reserve Distribution Amount;</del>
	<del>RT Uncertainty Reserve Non-Performance Amount;</del>
	<del>RT Uncertainty Reserve Non-Performance Distribution Amount;</del>
	RT Virtual Energy Amount;
	<del>RT Short-term Reserve Cost Distribution Amount;</del>
	<del>RT Short-term Reserve Deployment Failure Charge Amount;</del>

**MISO Transmission Service Settlement Schedules**

MISO Schedule 1 (System control & dispatch);	MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 2 (Reactive supply & voltage control);	MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 7 & 8 (Point to point transmission service);	MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 9 (Network transmission service);	MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);	MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);
MISO Schedules 26-C & 26-D - (TMEP Cost Recovery);	
MISO Schedules 26-E & 26-F (IMEP Cost Recovery);	
MISO Schedule 33 (Black Start Service);	

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St. Louis, Missouri  
ADDRESS

**Schedule AMM-D3**

**RIDER FAC**

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

**FAC CHARGE TYPE TABLE (Cont'd.)**

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

**MISO Charge Types Which Appear On MISO Settlement Statements Represent**

**Administrative Charges And Are Specifically Excluded From The FAC**

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

**PJM Market Settlement Charge Types**

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

**PJM Transmission Service Charge Types**

Black Start Service;	Network Integration Transmission Service Offset;
Day-ahead Scheduling Reserve;	Non-Firm Point-to-Point Transmission Service;
Direct Assignment Facilities;	Non-Zone Network Integration Transmission Service;
Expansion Cost Recovery;	Other Supporting Facilities;
Firm Point-to-Point Transmission Service;	PJM Scheduling, System Control and Dispatch Service Refunds;
Internal Firm Point-to-Point Transmission Service;	PJM Scheduling, System Control and Dispatch Services;
Internal Non-Firm Point-to-Point Transmission Service;	Qualifying Transmission Upgrade Compliance Penalty;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;	Reactive Supply and Voltage Control from Generation and Other Sources Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;	Transmission Enhancement;
Load Reconciliation for Reactive Services;	Transmission Owner Scheduling, System Control and Dispatch Service;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;	Unscheduled Transmission Service;
Network Integration Transmission Service;	Reactive Services;
Network Integration Transmission Service (exempt);	

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NAME OF OFFICER TITLE ADDRESS

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

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

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

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

**SPP Market Settlement Charge Types**

- |  |  |
|--|--|
| <u>DA Asset Energy Amount;</u>                                       | <u>RT Asset Energy Amount;</u>                                   |
| <u>DA Demand Reduction Amount;</u>                                   | <u>RT Contingency Reserve Deployment Failure;</u>                |
| <u>DA Demand Reduction Distribution Amount;</u>                      | <u>RT Contingency Reserve Deployment Failure Distribution;</u>   |
| <u>DA GFA Carve-Out Daily Amount;</u>                                | <u>RT Demand Reduction Amount;</u>                               |
| <u>DA GFA Carve-Out Monthly Amount;</u>                              | <u>RT Demand Reduction Distribution Amount;</u>                  |
| <u>DA GFA Carve-Out Yearly Amount;</u>                               | <u>RT Joint Operating Agreement;</u>                             |
| <u>DA Make-Whole Payment;</u>  | <u>RT Joint Operating Agreement Distribution Amount;</u>         |
| <u>DA Make-Whole Payment Distribution;</u>                           | <u>RT Miscellaneous Amount;</u>                                  |
| <u>DA Non-Asset Energy Amount;</u>                                   | <u>RT Non-Asset Energy;</u>                                      |
| <u>DA Ramp Capability Down Amount;</u>                               | <u>RT Over Collected Losses Distribution;</u>                    |
| <u>DA Ramp Capability Down Distribution Amount;</u>                  | <u>RT Out-of-Merit Distribution Amount;</u>                      |
| <u>DA Ramp Capability Up Amount;</u>                                 | <u>RT Price Correction Amount;</u>                               |
| <u>DA Ramp Capability Up Distribution Amount;</u>                    | <u>RT Price Correction Amount Distribution Amount;</u>           |
| <u>DA Regulation Down;</u>   | <u>RT Pseudo-Tie Congestion Amount;</u>                          |
| <u>DA Regulation Down Distribution;</u>                              | <u>RT Pseudo-Tie Distribution Amount;</u>                        |
| <u>DA Regulation Up;</u>   | <u>RT Pseudo-Tie Losses Amount;</u>                              |
| <u>DA Regulation Up Distribution;</u>                                | <u>RT Ramp Capability Down Amount;</u>                           |
| <u>DA Spinning Reserve;</u>  | <u>RT Ramp Capability Down Distribution Amount;</u>              |
| <u>DA Spinning Reserve Distribution;</u>                             | <u>RT Ramp Capability Non-Performance Amount;</u>                |
| <u>DA Supplemental Reserve;</u>                                      | <u>RT Ramp Capability Non-Performance Distribution;</u>          |
| <u>DA Supplemental Reserve Distribution;</u>                         | <u>RT Ramp Capability Up Amount;</u>                             |
| <u>DA Transmission Congestion Rights Near B. Tie Funding Amount;</u> | <u>RT Ramp Capability Up Distribution Amount;</u>                |
| <u>DA Uncertainty Reserve Amount;</u>                                | <u>RT Regulation Deployment Adjustment;</u>                      |
| <u>DA Uncertainty Reserve Distribution Amount;</u>                   | <u>RT Regulation Down;</u>                                       |
| <u>DA Virtual Energy;</u>  | <u>RT Regulation Down Distribution;</u>                          |
| <u>DA Virtual Energy Transaction Fee;</u>                            | <u>RT Regulation Non-Performance;</u>                            |
| <u>Auction Revenue Rights Annual Closeout;</u>                       | <u>RT Regulation Non-Performance Distribution;</u>               |
| <u>Auction Revenue Rights Annual Payback;</u>                        | <u>RT Regulation Out of Merit;</u>                               |
| <u>Auction Revenue Rights Funding;</u>                               | <u>RT Regulation Up;</u>   |
| <u>Auction Revenue Rights Monthly Payback;</u>                       | <u>RT Regulation Up Distribution;</u>                            |
| <u>Auction Revenue Rights Uplift;</u>                                | <u>RT Regulation Service Deployment Adjustment Distr Amount;</u> |
| <u>GFA Carve Out Distribution Daily Amount;</u>                      | <u>RT Reserve Sharing Group;</u>                                 |
| <u>GFA Carve Out Distribution Monthly Amount;</u>                    | <u>RT Reserve Sharing Group Distribution;</u>                    |
| <u>GFA Carve Out Distribution Yearly Amount;</u>                     | <u>RT Revenue Neutrality Uplift;</u>                             |

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**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

Original SHEET NO. 72.15

CANCELLING MO.P.S.C. SCHEDULE NO. \_\_\_\_\_

SHEET NO. \_\_\_\_\_

APPLYING TO MISSOURI SERVICE AREA

<u>Incremental Market Efficiency Use Amount;</u>	<u>RT Spinning Reserve Amount;</u>
<u>Incremental Market Efficiency Use Distr Amount;</u>	<u>RT Spinning Reserve Cost Distribution Amount;</u>
<u>RUC Make Whole Payment;</u>	<u>RT Supplemental Reserve Amount;</u>
<u>RUC Make Whole Payment Distribution;</u>	<u>RT Supplemental Reserve Distribution Amount;</u>
<u>Transmission Congestion Rights Annual Closeout;</u>	<u>RT Transmission Congestion Rights West DC Tie Funding Amount;</u>
<u>Transmission Congestion Rights Annual Payback;</u>	<u>RT Uncertainty Reserve Amount;</u>
<u>Transmission Congestion Rights Auction Transaction;</u>	<u>RT Uncertainty Reserve Distribution Amount;</u>
<u>Transmission Congestion Rights Daily Uplift;</u>	<u>RT Uncertainty Reserve Non-Performance Amount;</u>
<u>Transmission Congestion Rights Funding;</u>	<u>RT Uncertainty Reserve Non-Performance Distr Amount;</u>
<u>Transmission Congestion Rights Annual Closeout;</u>	<u>RT Unused Regulation Down Mileage Make Whole Payment;</u>
<u>West DC Tie Federal Service Exemption Amount;</u>	<u>RT Unused Regulation Up Mileage Make Whole Payment;</u>
	<u>RT Virtual Energy Amount</u>

**SPP Transmission Service Charge Types**

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

**SPP Charge Types Representing Administrative Charges Specifically Excluded From The FAC**

- Schedule 1A - Tariff Administrative Fee;
- Schedule 1A2 - Transmission Congestion Rights Administration;
- Schedule 1A3 - Integrated Marketplace Clearing Administration;
- Schedule 1A4 - Integrated Marketplace Facilitation Administration;
- Schedule 12 - FERC Assessment;

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**Schedule AMM-D3**

**UNION ELECTRIC COMPANY**

**ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6

2nd Revised

SHEET NO. 72.16

CANCELLING MO.P.S.C. SCHEDULE NO. 6

1st Revised

SHEET NO. 72.14

APPLYING TO

**MISSOURI SERVICE AREA**

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