BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Application of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. for Approval to Make Certain Changes in their Charges for Electric Service.	)	**Docket No. 25-EKCE-294-RTS**

Direct Testimony and Exhibits of

Brian C. Andrews

On behalf of

Associated Purchasing Services,
Cargill, Incorporated,
CVR Refining CVL, LLC,
Goodyear Tire & Rubber Company,
Kansas Agribusiness Retailers Association,
Kansas Biofuels Association,
Kansas Grain and Feed Association,
Lawrence Paper Company,
Occidental Chemical Corporation,
and Spirit AeroSystems, Inc.

June 6, 2025

BRUBAKER & ASSOCIATES, INC.

Projects 11807

BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Application of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. for Approval to Make Certain Changes in their Charges for Electric Service.	)))))))	**Docket No. 25-EKCE-294-RTS**

STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Brian C. Andrews

Brian C. Andrews, being first duly sworn, on his oath states:

1. My name is Brian C. Andrews. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Associated Purchasing Services, Cargill, Incorporated, CVR Refining CVL, LLC, Goodyear Tire & Rubber Company, Kansas Agribusiness Retailers Association, Kansas Biofuels Association, Kansas Grain and Feed Association, Lawrence Paper Company, Occidental Chemical Corporation, and Spirit AeroSystems, Inc.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Kansas State Corporation Commission Docket No. 25-EKCE-294-RTS.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

Brian C. Andrews

Subscribed and sworn to before me this 6th day of June, 2025.

ADRIENNE J. FOLLETT
Notary Public - Notary Seal
STATE OF MISSOURI
Jefferson County
My Commission Expires: Mar. 22, 2029
Commission # 21989987

Notary Public

BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Application of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. for Approval to Make Certain Changes in their Charges for Electric Service.	)))))))	**Docket No. 25-EKCE-294-RTS**

Table of Contents to the
<u>Direct Testimony of Brian C. Andrews</u>

<u>Page</u>

BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Application of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. for Approval to Make Certain Changes in their Charges for Electric Service.	)))))))	**Docket No. 25-EKCE-294-RTS**

Direct Testimony of Brian C. Andrews

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of multiple Commercial Intervenors and Kansas Agricultural Associations in this Docket, including Associated Purchasing Services, Cargill, Incorporated, CVR Refining CVL, LLC, Goodyear Tire & Rubber

Company, Kansas Agribusiness Retailers Association, Kansas Biofuels Association, Kansas Grain and Feed Association, Lawrence Paper Company, Occidental Chemical Corporation, and Spirit AeroSystems, Inc. These parties are referenced throughout this testimony as "Commercial Intervenors." These Commercial customers purchase substantial amounts of retail electric service from Kansas Central, Inc. and Evergy Kansas South, Inc. (collectively referred to as "Evergy Kansas Central" or "EKC") and Evergy Kansas Metro Inc. ("EKM"). The companies collectively will be referred to as "Evergy" or "Company".

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A I will address Evergy's Class Cost of Service Studies ("CCOSS"), the Company's proposed revenue apportionment, and certain rate design issues related to the Industrial classes, as well as Evergy's Retail Energy Cost Adjustment ("RECA") and Energy Cost Adjustment ("ECA") mechanisms.

My silence with respect to any position taken by Evergy should not be construed as agreement with that position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. Evergy's proposed CCOSS with fixed production costs allocated using the Four Coincident Peak ("4CP") Average and Excess Demand ("AED") allocator is reasonable and should be approved by the Kansas State Corporation Commission ("Commission").

2. Evergy's proposed revenue apportionment is only capped at 1.1x the system average increase and does not reflect meaningful movement toward cost of service and is not reasonable. I propose a revenue apportionment that would cap any classes' rate increase to no more than 1.2x the system average increase.

3. Evergy's base rates for Large General Service ("LGS") and Industrial and Large Power Service ("ILP") include voltage-differentiated demand and energy charges.

I support Evergy's proposal to maintain voltage-differentiated demand and energy charges in order to more accurately reflect cost-causation within these customer classes.

4. I recommend that the Optional Time-of-Use ("TOU") rates for Commercial and Industrial ("C&I") be calculated as revenue neutral at the class level to ensure that transmission rates are lower than primary rates, which are lower than secondary rates.

5. The RECA and ECA rates for EKC and EKM should be voltage-differentiated to account for line losses that make it more expensive to provide energy to lower voltage customers than higher voltage customers. I recommend the Commission modify the RECA and ECA to reflect energy rate voltage-differentials.

II. CLASS COST OF SERVICE STUDIES

Q PLEASE EXPLAIN THE BASIC STEPS FOR ESTABLISHMENT OF FAIR AND REASONABLE RATES.

A The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how the revenues are to be distributed among the various customer classes or schedules. A determination of how many dollars of revenue should be produced by each class is essential to obtaining the appropriate level of rates. This is called "revenue allocation" or "revenue spread." Finally, individual tariffs must be designed to produce the required amount of revenues from each class of service and to send efficient price signals to customers.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is widely agreed that the utility is entitled to a revenue increase only to the extent that its actual overall cost of service has increased. If current rate levels exceed the revenue requirement, a rate reduction is required. In short, rate revenues should equal a utility's actual cost of service. The same principle should apply in the last two steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class. On some occasions, this may require a rate increase for some customer classes and a rate decrease for others. The standard tool for determining whether a class requires a rate increase or decrease is a CCOSS, which shows the rate of return for each class of service. Ideally, rate levels should be modified so that each customer class provides approximately the same rate of return.

Finally, in designing individual tariffs, the goal is to base the rate design on the cost of service, so that each customer's rate tracks, to the extent practicable, the utility's cost of providing that service to the customers on the tariff.

Q WHAT IS THE BASIC PURPOSE OF A COST OF SERVICE STUDY?

A The basic purpose of a cost of service study is an empirical determination of the cost of serving the various classes of customers.

After determining the overall cost of service or revenue requirement, a cost of service study is used to ascertain the cost of serving each of the various customer classes (i.e., a cost of service study shows how each customer class contributes to the total system cost). For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues sufficient to cover the costs incurred in serving it (including a reasonable authorized return on investment). If a class produces a below-average rate of return, it may be concluded that the revenues are insufficient to cover all relevant costs. On the other hand, if a class produces a rate of return above the average, it is paying revenues sufficient to cover the cost attributable to it and, in addition, is paying part of the cost attributable to other classes who produce a below average rate of return. The cost of service study is important because it shows the class revenue requirement as well as the rate of return under current and any proposed rates.

As a measurement or estimation tool, the cost of service study is not the step in which other factors, such as rate moderation or continuity, should be considered or allowed to influence the results. Those types of considerations are taken up in the revenue allocation and rate design steps.

Q PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A CCOSS.

A In all CCOSS, certain fundamental concepts should be recognized. Of primary importance among these concepts is the functionalization of costs, as well as the classification of the nature of these costs as to whether they vary with the quantity of energy consumed, the demand placed upon the system, or the number of customers being served. Stated another way, functionalization is the classification and arrangement of costs according to major functions, such as production, transmission, and distribution.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in output and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the investment in utility facilities, and those costs necessary to keep the facilities "on-line." Variable costs, on the other hand, are those costs which tend to vary with output and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of energy consumed or the peak demands placed upon the system. An understanding of these concepts is essential to the development of CCOSS, as well as appropriate rate design.

Q WHY DOES DELIVERY VOLTAGE IMPACT EVERGY'S COST OF SERVICE FOR CUSTOMERS?

A Delivery voltage impacts cost of service due to line losses and the distribution equipment needed to deliver power from the voltage level used to transport power from the generation resource to the voltage at the customer meter. The difference in voltage between generation and meter impacts the amount of generation and transmission capacity needed to supply the customer's power demands at the meter and the amount of production energy costs (i.e., fuel and purchased energy) incurred to deliver a kilowatthour ("kWh") of energy to the customer meter. Also, delivery voltage differentials can impact Evergy's cost of distribution equipment necessary to step down the voltage to the delivery voltage at the meter.

Evergy must have adequate generation and transmission capacity in order to deliver a kilowatt ("kW") and kWh from the generation resource to the customer meter. The amount of capacity and energy needed to deliver the kW and kWh at the customer meter depends on the losses that are experienced between the generation resource and the customer meter.

Evergy estimates that for a transmission level delivery service customer, it incurs losses of 3.0%[1] in delivering energy to a customer meter served at a transmission delivery voltage. This means that it must produce 1.03 kWh in order to deliver 1 kWh at a transmission delivery voltage meter. Similarly, Evergy estimates energy losses from generation service of 4.761% and 7.775% for primary and secondary delivery service voltage.[2]

[1] Marisol Miller Workpaper – "QGas Utilities-1_CONF_Evergy (KS Central) Allocators Workpapers 2025.xlsx" at KS Central Losses Tab.

[2] *Id*.

In each instance, Evergy must incur the cost of more demand and energy at the generation resource in order to deliver the power to the customer at the meter.

Additionally, Evergy's cost of distribution equipment also varies depending on the delivery service voltage. Evergy's primary and secondary distribution equipment is not used to provide service to a transmission level customer. These transmission customers take power off of Evergy's transmission system without use of its primary and secondary distribution infrastructure. Similarly, primary customers receive service from Evergy without the use of its secondary distribution equipment.

Q HAVE YOU REVIEWED EVERGY'S CCOSS MODEL?

A Yes. I have reviewed Evergy's CCOSS that was submitted as part of witness Marisol E. Miller's Direct Testimony in this case.

Q HOW HAS EVERGY ALLOCATED PRODUCTION-RELATED FIXED COSTS IN THE CCOSS?

A Ms. Miller recommends using a combination of AED and 4CP methodology.[3] Ms. Miller refers to this costing method as the "AED-4CP" since the excess demand component of the AED method is determined using 4CP.

Both the AED and the Coincident Peak ("CP") methods are utilized within the industry and can provide reasonable estimates of CCOSS, if applied properly. In addition, one of the seminal guides on electric utility cost allocation recognizes these approaches.[4] Further, this methodology is consistent with the method used by the Company in at least the last two rate cases.

---

[3]See the Direct Testimony of Marisol E. Miller at page 11.

[4]"Electric Utility Cost Allocation Manual," January 1992, NARUC Manual, pages 41-44 and 49-52.

Q HOW HAS EVERGY ALLOCATED DISTRIBUTION COSTS IN THE CCOSS?

A Distribution plant is allocated using either a demand or customer allocation factor, depending on the account.[5] Specifically, Accounts 360 through 363 are classified as demand-related and allocated using class Non-Coincident Peak ("NCP") demands.[6] Accounts 364 through 368 include both a demand and a customer component, where the demand-related component is allocated using NCP demand, and the customer component is allocated on the basis of the number of customers in each class.[7] The customer-related portion of distribution costs has been developed based on a minimum system method.[8] The remaining distribution plant accounts (Accounts 369 through 373) were allocated using a customer allocation factor.[9]

Q IS IT REASONABLE TO RECOGNIZE BOTH A DEMAND- AND CUSTOMER-RELATED PORTION OF DISTRIBUTION PLANT FOR ACCOUNTS 364 THROUGH 368?

A Yes. Chapter 6 of the 1992 National Association of Regulatory Utility Commissioners ("NARUC") Manual ("NARUC Manual") describes methods for classifying distribution Accounts 364 through 368 and classification methods containing both customer and demand components. None are shown as demand only. Multiple methods for determining the demand and energy classification are discussed, such as Minimum System and Zero Intercept approaches, yet none yield results of zero cost being classified as customer-related for these accounts.

---

[5] See the Direct Testimony of Marisol E. Miller at pages 12-13.
[6] *Ibid.*
[7] *Ibid.*
[8] *Ibid.*
[9] *Ibid.*

In addition to the wide acceptance in the industry and inclusion in the NARUC Manual, it requires a little more than common sense to understand that some portion of the installation of poles, conductors, underground conduit and conductors, and line transformers are simply to connect customers to the grid, even though their demands may be very small, well below the capacity of the minimum sized facilities needed to serve them. The aggregate demand level of customers certainly affects the sizing of these distribution facilities (over and above the minimum levels), but that does not in any way nullify the fact that a portion of the investment is in the minimum system and caused by the existence of the customers.

Q IN TERMS OF PARTIAL ENERGY-BASED PRODUCTION CAPACITY COST ALLOCATION METHODS, IS THE AED METHOD MORE REASONABLE THAN OTHER METHODS LIKE THE PEAK AND AVERAGE ("P&A")?

A Yes. Methods such as the P&A do not properly recognize the capacity costs incurred to serve each classes' peak load in *excess* of the base (or average) load. The P&A method double counts the average demand component of the allocator – once in the average demand component, and once in the peak demand component of the allocator. This method over-allocates production capacity costs to energy intensive customers, effectively penalizing higher load factor customers for using system capacity more efficiently than lower load factor customer classes.

Q ARE THE COMPANY'S CCOSS REASONABLE TO USE AS A BASIS FOR REVENUE ALLOCATION AND RATE DESIGN IN THIS CASE?

A I am generally in agreement with the Company's proposal to allocate production fixed costs based on the AED-4CP. The demands have been adjusted for losses to be stated at the production level and the load factor is based on a single CP. Overall, the Company's CCOSS appears to be reasonable.

III. REVENUE APPORTIONMENT

Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED REVENUE APPORTIONMENT?

A Yes. Comparisons of the Company's proposed revenue apportionment versus the CCOSS results for EKC is shown below in Table 1.

TABLE 1

EKC's Cost of Service Study Results vs. Proposed Revenue Spread

Line	Description	Current Base Rate Revenues[1]	Increase / (Decrease) to Reach Cost of Service[2]			Company Proposed Increase / (Decrease)[3]		
			Amount	Percent	Index	Amount	Percent	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential	$ 640,306,516	$ 253,515,793	39.6%	2.91	$ 95,690,048	14.9%	1.10
2	Residential DG	5,403,843	1,504,824	27.8%	2.05	807,571	14.9%	1.10
3	Small General Service	292,682,279	(25,932,947)	-8.9%	(0.65)	36,910,063	12.6%	0.93
4	Medium General Service	153,953,501	(28,306,828)	-18.4%	(1.35)	18,352,200	11.9%	0.88
5	Large General Service	191,532,412	(32,254,979)	-16.8%	(1.24)	22,805,197	11.9%	0.88
6	Industrial and Large Power Service	24,475,789	948,573	3.9%	0.29	3,236,828	13.2%	0.97
7	Educational Service	38,067,845	14,302,614	37.6%	2.77	5,679,214	14.9%	1.10
8	Restricted Time of Day Service	1,209,672	723,539	59.8%	4.40	180,421	14.9%	1.10
9	Special Contracts	32,986,239	23,230,273	70.4%	5.18	4,362,302	13.2%	0.97
10	Interruptible Contract Service	1,069,498	(439,263)	-41.1%	(3.02)	129,535	12.1%	0.89
11	Large Tire Manufacturer	4,770,313	(1,402,875)	-29.4%	(2.16)	577,769	12.1%	0.89
12	Electric Vehicle	11,332	843,766	7446.1%	548.08	87,331	770.7%	56.73
13	Lighting	27,405,542	(14,645,639)	-53.4%	(3.93)	3,268,373	11.9%	0.88
14	Total	$ 1,413,874,780	$ 192,086,852	13.6%	1.00	$ 192,086,852	13.6%	1.00

Sources:
[1] Schedule MEM-1
[2] Evergy (KS Central) 2025 CCOS Model - DIRECT FINAL.xlsx, "COS Summary" tab
[3] Schedule MEM-2.

As shown in Table 1, EKC's CCOSS shows that a wide range of rate increases, and in some cases decreases, would be needed to bring all of the customer classes to cost of service. For example, some classes would require increases in excess of 5x the system average, while others would require rate decreases to reach parity. It is clear that mitigation is reasonable, and the Company's proposed revenue apportionment does not achieve that objective. Under the Company's proposed revenue spread, no class receives a rate decrease, and several classes have been limited to an increase of no more than 1.1x the system average. This simply is not an acceptable move towards more cost based rates. In EKC's last rate case, in which they had proposed a system increase of 22.0%, the Company capped the Residential increase at 113% of the system average increase, resulting in a proposed increase of 24.9%.[10] Because the overall rate increase is lower than the previous rate case, it would make sense to allow for more aggressive movement towards cost-based rates. In the instant proceeding, the Residential class is shown to require a nearly 40% increase to bring this class to its cost of service; an increase of more than 14.87% is justified.

Q DO YOU HAVE AN ALTERNATIVE REVENUE APPORTIONMENT PROPOSAL TO OFFER FOR CONSIDERATION?

A Yes. I have developed an alternative revenue apportionment proposal that I am recommending for approval. In this proposal, I have capped the Residential, Churches, Schools, and EV/CCN class at 1.2x the system average increase, yielding an increase to the Residential class of 16.32%. These were the classes that Evergy had capped at 1.1x the system average increase. For all the other proposed class rate increases, I scaled the increases by a factor of 0.9, which was calculated to generate the total proposed revenue. For example, Evergy had proposed that the Small General Service ("SGS") class was to receive an increase 93% of the system average increase, or 12.64%. After setting the Residential, Churches, Schools, and EV/CCN at 1.2x the system average increase, I then calculated a scalar to apply to the 93% factor that Evergy used. This scaling factor was applied to the 96% Evergy used for Large Power ("ILP" or "LPS") and Special Contracts, the 93% used for SGS, and finally the 88% that was used for LGS and Medium General Service ("MGS"), Large Tire

[10] See the Direct Testimony of Marisol E. Miller at pages 66-67 in Docket No. 23-EKCE-775-RTS.

Manufacturer ("LTM"), Interruptible Classes, and Lighting. My proposed revenue apportionment proposal is shown in Table 2 below. This proposal will help bring the Residential class closer to its cost of service compared to Evergy's proposal. This revenue apportionment is shown in more detail in my Exhibit BCA-1, which is an updated version of Ms. Marisol's Schedule MEM-2.

TABLE 2

EKC vs. BCA Proposed Revenue Spread

		Current Base Rate	Company Proposed Increase / (Decrease)[2]			BCA Proposed Increase / (Decrease)[3]			Difference	
Line	Description	Revenues[1]	Amount	Percent	Index	Amount	Percent	Index	Amount	Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Residential	$ 640,306,516	$ 95,690,048	14.9%	1.10	$ 104,403,579	16.3%	1.20	$ 8,713,531	9.1%
2	Residential DG	5,403,843	807,571	14.9%	1.10	881,108	16.3%	1.20	73,537	9.1%
3	Small General Service	292,682,279	36,910,063	12.6%	0.93	33,071,449	11.3%	0.83	(3,838,614)	-10.4%
4	Medium General Service	153,953,501	18,352,200	11.9%	0.88	16,443,587	10.7%	0.79	(1,908,613)	-10.4%
5	Large General Service	191,532,412	22,805,197	11.9%	0.88	20,435,547	10.7%	0.79	(2,369,650)	-10.4%
6	Industrial and Large Power Service	24,475,789	3,236,828	13.2%	0.97	2,900,200	11.8%	0.87	(336,627)	-10.4%
7	Educational Service	38,067,845	5,679,214	14.9%	1.10	6,196,363	16.3%	1.20	517,149	9.1%
8	Restricted Time of Day Service	1,209,672	180,421	14.9%	1.10	196,850	16.3%	1.20	16,429	9.1%
9	Special Contracts	32,986,239	4,362,302	13.2%	0.97	3,908,626	11.8%	0.87	(453,676)	-10.4%
10	Interruptible Contract Service	1,069,498	129,535	12.1%	0.89	116,064	10.9%	0.80	(13,472)	-10.4%
11	Large Tire Manufacturer	4,770,313	577,769	12.1%	0.89	517,682	10.9%	0.80	(60,087)	-10.4%
12	Electric Vehicle	11,332	87,331	770.7%	56.73	87,331	770.7%	56.73	-	0.0%
13	Lighting	27,405,542	3,268,373	11.9%	0.88	2,928,465	10.7%	0.79	(339,908)	-10.4%
14	Total	$ 1,413,874,780	$ 192,086,852	13.6%	1.00	$ 192,086,852	13.6%	1.00	$ 0	0.0%

Sources:
[1] Schedule MEM-1
[2] Schedule MEM-2.
[3] Exhibit BCA-1

IV. RATE DESIGN

IV.A. LGS and LPS Voltage Differentials

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED BASE RATE DESIGN FOR THE EKC'S LGS AND LPS CLASSES.

A The LGS and LPS classes' rate structures include a monthly customer charge, voltage-differentiated demand charges, and voltage-differentiated energy charges. The Company proposes to maintain the existing rate structure for both of these classes, but to increase each rate component by approximately the class average increase to recover the revenue requirement allocated to these classes.

Q IS IT REASONABLE TO MAINTAIN DEMAND AND ENERGY CHARGE VOLTAGE-DIFFERENTIALS FOR THE LGS AND LPS CUSTOMER CLASSES?

A Yes. These customer classes include customers that take service from a variety of delivery voltage levels including secondary, primary, and transmission. As described in the cost of service section of this testimony, customers served at different voltage levels utilize system infrastructure differently, and also impose different levels of line losses on the system. Because the Company's CCOSS allocates costs to each of these classes as a whole, rather than allocating costs to the voltage level subclasses, it is reasonable to continue reflecting voltage-differentials in the rate design.

IV.B. Optional TOU Rate Proposal for C&I Customers

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED OPTIONAL TOU RATE PROPOSAL FOR C&I CUSTOMERS.

A Consistent with the settlement agreement in the previous rate case, Evergy has proposed an optional TOU rate proposal for the C&I customers. The rate proposal is described in detail in the Direct Testimony of Brad Lutz, and in his Schedule BDL-1. The rate structure is a three-period, four-part rate that will be available to the MGS, LGS, and LPS classes. The four-part design consists of a customer charge, facilities charge, demand charge, and energy charge. The summer energy charges have three-periods; on-peak, off-peak, and super-off-peak. For winter, there is just off-peak and super-off-peak.

Q ARE YOU GENERALLY SUPPORTIVE OF THE THESE OPTIONAL TOU RATES?

A Yes, I am supportive of these rates and appreciate Evergy working with customers to develop these rates. I do, however, have some concerns with how the energy charges have been calculated.

Q PLEASE DISCUSS YOUR CONCERN WITH THE ENERGY CHARGES.

A While Mr. Lutz states that the rate design has been conducted to remain revenue neutral at the class level,[11] inspection of the workpapers that were used to develop the rates shows that the rate design was actually conducted to be revenue neutral for the voltage levels within each class. This leads to energy rates that are unreasonable. On page 13 of Schedule BDL-1, which is also shown in Table 1 on page 7 of Mr. Lutz's Direct Testimony, it shows the illustrative rates for this Optional TOU rate. I will discuss only the Summer On-Peak energy rate, but the issue exists for all periods. For LPS, the transmission Summer On-Peak energy rate is $0.09194/kWh, while the primary rate is just $0.07580. For LPS, all the transmission level energy rates are 21% higher than the primary rates. As I have discussed earlier in testimony, and has been confirmed by Evergy, a transmission level customer causes Evergy to incur a lower amount of cost to provide energy, relative to primary and secondary customers. This is due to the line losses, which are lower for transmission level customers and higher for secondary and primary voltage level customers. This issue also exists for the LGS rates, which have the Summer On-Peak energy charge of $0.10753/kWh for transmission customers, compared to $0.09283 for the primary customers, and $0.10079 for the secondary customers. To follow obvious cost-causation realities, this

[11]Direct Testimony of Brad Lutz at page 7, lines 2-3 and page 9, lines 21-22.

rate design must be conducted to ensure that transmission rates are lower than primary rates, which are lower than secondary rates.

Q IN DEVELOPING THE OPTIONAL TOU RATES, HOW DID EVERGY DETERMINE THE REVENUE TARGETS FOR EACH VOLTAGE LEVEL WITHIN EACH CLASS?

A The revenue targets for each voltage level within each of the rate classes were derived from Evergy's proof of revenue at their proposed rates and test year billing determinants. For example, the LPS transmission revenue was calculated by multiplying the test year billing determinants by the proposed LPS transmission rates. This total revenue was then used to discreetly calculate all the Optional TOU rates for the transmission customers.

Q ARE THE REVENUE TARGETS FOR EACH VOLTAGE CLASS BASED ON A CCOSS?

A No. Evergy's CCOSS does not allocate costs to each voltage class within the classes. The allocation is performed at the class level. Therefore, the split of costs between the voltage levels in each class are not based purely on cost-causation principals, but rather on legacy rate design.

Q DO YOU HAVE A SUGGESTED CORRECTION FOR THE ENERGY RATES FOR THE OPTIONAL TOU RATES?

A Yes. To be consistent with Mr. Lutz's testimony, and to ensure that transmission rates are lower than primary rates, which are lower than secondary rates, the rate calculation needs to be conducted at the class level, rather than the voltage levels within the class.

Then loss factors can be applied to ensure the proper relationship between the voltage levels.

Q HAVE YOU CONDUCTED A RECALCULATION OF THE LGS TOU ENERGY RATES CONSISTENT WITH YOUR RECOMMENDATION?

A Yes. In my Exhibit BCA-2, I provide the energy rate calculations for LGS. To illustrate the change, in Table 3 below, I show only the Summer On-Peak rate.

TABLE 3

Comparison of EKC and BCA Proposed Optional LGS TOU Rate for the Summer On-Peak Period

Line	Description	LGS Secondary (1)	LGS Primary (2)	LGS Transmission (3)
1	EKC Proposed Rates [1]	$ 0.10079	$ 0.09283	$ 0.10753
2	BCA Proposed Rates [2]	0.09890	0.09613	0.09450
3	Difference	(0.00189)	0.00330	(0.01303)

Sources:

[1] Exhibit BDL-1, page 3, Table ES-1

[2] Exhibit BCA-2

As can be seen, this rate design ensures the proper relationship between the voltage levels within the LGS class. The transmission rate is lower than the primary rate, which is lower than the secondary rate. This rate design is revenue neutral at the class level, in line with Mr. Lutz testimony and sound rate design principals.

Q HAVE YOU CONDUCTED A RECALCULATION OF THE LPS TOU ENERGY RATES CONSISTENT WITH YOUR RECOMMENDATION?

A Yes. In my Exhibit BCA-3, I provide the energy rate calculations for LPS. To illustrate the change, in Table 4 below, I show only the Summer On-Peak rate.

TABLE 4

Comparison of EKC and BCA Proposed Optional LPS TOU Rate for the Summer On-Peak Period

Line	Description	LPS Primary (1)	LPS Transmission (2)
1	EKC Proposed Rates [1]	$ 0.07580	$ 0.09194
2	BCA Proposed Rates [2]	0.08091	0.07956
3	Difference	0.00511	(0.01238)

Sources:

[1] Exhibit BDL-1, page 3, Table ES-1

[2] Exhibit BCA-3

As can be seen, this rate design ensures the proper relationship between the voltage levels within the LPS class. The transmission rate is lower than the primary rate. Consistent with Evergy's proposal, and to recognize the fact there are no secondary LPS customers, the secondary and primary rates are identical. As with LGS, this LPS rate design is revenue neutral at the class level, in line with Mr. Lutz testimony and sound rate design principals.

IV.C. Optional TOU Rate Proposal for C&I Customers

Q PLEASE DISCUSS EVERGY'S ECA MECHANISMS.

A Evergy uses the RECA and ECA mechanisms to recover variable costs primarily associated with fuel and purchased power. The RECA and ECA rates reflect a single, flat rate per kWh applicable to all customer classes. It is not differentiated by rate class, delivery voltage, or TOU.

Q DO YOU RECOMMEND ANY IMPROVEMENTS TO THE RECA AND ECA?

A Yes, I recommend two improvements to the design of charges to these rider mechanisms. First, the riders should have time-differentiated charges. I discuss this in greater detail below, in my recommended time-differentiated rate section. Second, the riders should reflect adjustments for delivery losses based on the delivery voltage of the various rate classes. The delivery losses are a material cost. The energy loss to deliver a kWh to a customer that takes service at a secondary voltage meter is much larger than the delivery losses for a customer that is served at a transmission level delivery voltage. The energy charges should reflect this delivery costs for losses.

Q DO OTHER REGIONAL ELECTRIC UTILITIES HAVE VOLTAGE-DIFFERENTIALS FOR ENERGY CHARGES IN THEIR FUEL ADJUSTMENT CLAUSES?

A Yes. I have conducted research on the fuel adjustment clauses of several Midwest regional electric utilities. I have summarized this research in Table 5. I have included all of the referenced tariffs in my Exhibit BCA-4.

TABLE 5

Midwest Utility Fuel Rider Comparison

Utility (1)	State (2)	Rate Schedule (3)	Voltage Differential (4)
Evergy Kansas Central	Kansas	Retail Energy Cost Adjustment	X
Ameren Missouri	Missouri	Rider FAC	✓
Entergy Arkansas, Inc.	Arkansas	Energy Cost Recovery Rider/Voltage Adjustment Rider	✓
Evergy Missouri	Missouri	Rider FAC	✓
Evergy Kansas Metro	Kansas	Energy Cost Adjustment	X
MidAmerican Energy	Iowa	Energy Adjustment Clause	X
Minnesota Power Company	Minnesota	Fuel and Purchased Energy Adjustment	✓
Northern States Power Company	Minnesota	Fuel Clause Rider	✓
Northwestern Energy	South Dakota	Delivered Cost of Fuel	X
OG&E Electric Services	Oklahoma	Fuel Cost Adjustment	✓
Otter Tail Power Company	North Dakota	Energy Adjustment Rider	X
Public Service Company of Oklahoma	Oklahoma	Fuel Cost Adjustment	✓
Southwestern Electric Power Company	Arkansas	Energy Cost Recovery Rider	✓
Wisconsin Electric Power Company	Wisconsin	Cost of Fuel Adjustment	X
Alliant Energy (WP&L)	Wisconsin	Fuel Adjustment	X

Source: Exhibit BCA-4

As shown in the table, several regional utilities account for the difference of the cost to serve the various voltage levels in their fuel cost adjustments.

In summary, losses are a major cost component in generating or purchasing electricity that is needed to supply customer demands at the customer's meter. A loss-based fuel and purchased power pricing factor is recognized by other utilities in the Midwest region for charging customers for the cost of fuel and purchased power energy. It is reasonable for Evergy to implement voltage-differentials in its RECA and ECA mechanisms now.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of BAI, energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As a Principal at BAI, and as an Associate, Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, Virginia, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

BCA Proposed Adjustments to Evergy - Kansas Central Class Revenue Summary
Docket No. 25-EKCE-294-RTS

Rate Increase: 13.60%

KANSAS RATE GROUP	Weather Normalized CG kWh	Revenue from Existing Rates (Including ECA, PTR, EER, TDC)	ECA Rider/Adjustments	PTR Rider/Adjustments	EER Rider/Adjustments	TDC Rider/Adjustments	EDR credits[2]	Standby Service Rider	RPC/RESRAM Charge	Solar Revenue	DRPS Charge
LARGE Pwr SVC TOTAL	629,373,799	$ 47,273,554	$ 14,446,102	$ 1,001,568	$ 124,198	$ 6,906,471	$ (94)	$ -	$ -	$ -	$ -
LARGE GEN SVC TOTAL	3,855,045,876	$ 328,839,939	$ 69,432,531	$ 6,151,534	$ 762,448	$ 47,260,004	$ (2,821,672)	$ 17,224	$ (1,819,184)	$ 41,976	$ 16,410,475
MEDIUM GEN SVC TOTAL	2,352,748,254	$ 247,877,423	$ 51,952,605	$ 3,796,336	$ 470,345	$ 35,984,923	$ (411,375)	$ -	$ (49,931)	$ -	$ 2,221,932
SMALL GEN SVC TOTAL	3,471,205,844	$ 436,714,001	$ 79,431,271	$ 5,605,323	$ 693,444	$ 58,175,472	$ (17,539)	$ -	$ 19,191	$ 22,475	$ 832,785
RESIDENTIAL	6,452,610,102	$ 920,775,398	$ 151,046,825	$ 10,532,190	$ 1,299,503	$ 117,739,629	$ -	$ -	$ -	$ 343,328	$ -
RESIDENTIAL DG	66,562,325	$ 8,011,771	$ 1,419,415	$ 98,340	$ 12,218	$ 1,082,124	$ (93,707)	$ -	$ -	$ -	$ -
Rate Class TOTALS	**16,827,546,201**	**$ 1,989,492,086**	**$ 367,728,749**	**$ 27,185,292**	**$ 3,362,156**	**$ 267,148,623**	**$ (3,344,387)**	**$ 17,224**	**$ (1,849,924)**	**$ 407,779**	**$ 19,465,192**
Churches	13,869,836	$ 1,790,745	$ 328,270	$ 22,830	$ 2,825	$ 230,162	$ -	$ -	$ 305	$ -	$ -
Schools	621,824,242	$ 65,899,543	$ 13,766,634	$ 1,003,838	$ 124,464	$ 12,553,726	$ (148)	$ -	$ (87,240)	$ -	$ 565,099
Large Tire Mfg	25,331,984	$ 9,471,220	$ 2,874,661	$ 199,093	$ 24,740	$ 1,540,157	$ -	$ -	$ -	$ -	$ -
EV	5,542,856	$ 928,261	$ 107,296	$ 8,053	$ 1,000	$ 87,967	$ -	$ -	$ -	$ -	$ 6,907
ICS	16,091,860	$ 1,693,404	$ -	$ 24,202	$ 2,995	$ 582,751	$ -	$ -	$ -	$ -	$ -
Special Contracts[1]	1,409,931,052	$ 75,896,584	$ 21,386,787	$ 2,208,744	$ 274,768	$ 16,160,860	$ (584,783)	$ -	$ 2,448,692	$ -	$ -
Lighting	101,451,719	$ 29,928,032	$ 2,297,559	$ 160,822	$ 427	$ 120,810	$ -	$ -	$ -	$ -	$ 11,137
TOTAL	**19,021,589,751**	**$ 2,175,099,874**	**$ 408,489,956**	**$ 30,812,874**	**$ 3,793,374**	**$ 298,425,057**	**$ (3,929,318)**	**$ 17,224**	**$ 511,832**	**$ 407,779**	**$ 20,048,336**

KANSAS RATE GROUP	Revenue from Existing Rates less ECA, PTR, EER, TDC adjustments	Revenue from Existing Rates grossed up to reflect EDR credits	Requested Increase-from Rev Model excluding EDR gross-up (Equal increase)	Evergy Proposed Revenue Shift	BCA Adjustment Scalar	BCA Proposed Revenue Shift	Requested Increase-from Rev Model excluding EDR gross-up (Rev Shifts)	Requested Increase-Including EDR Gross Up (equal)	Requested Increase-Including EDR Gross Up (Rev Shifts)	Proposed Revenue
LARGE Pwr SVC TOTAL	$ 24,795,216	$ 24,795,309	$ 3,371,695	96%	-10%	86%	$ 2,900,200	$ 3,371,708	$ 2,900,646	$ 27,695,416
LARGE GEN SVC TOTAL	$ 190,582,930	$ 193,404,602	$ 25,915,790	88%*	-10%*	79%*	$ 20,435,547	$ 26,299,486	$ 20,741,677	$ 211,018,478
MEDIUM GEN SVC TOTAL	$ 153,501,214	$ 153,912,589	$ 20,873,355	88%	-10%	79%	$ 16,443,587	$ 20,929,295	$ 16,489,799	$ 169,944,801
SMALL GEN SVC TOTAL	$ 291,934,039	$ 291,951,577	$ 39,697,686	93%	-10%	83%	$ 33,071,449	$ 39,700,071	$ 33,116,431	$ 325,005,488
RESIDENTIAL	$ 639,813,923	$ 639,813,923	$ 87,002,982	110%		120%	$ 104,403,579	$ 87,002,982	$ 104,403,579	$ 744,217,502
RESIDENTIAL DG	$ 5,399,673	$ 5,493,381	$ 734,257	110%		120%	$ 881,108	$ 746,999	$ 896,399	$ 6,280,781
Rate Class TOTALS	**$ 1,306,026,995**	**$ 1,309,371,382**	**$ 177,595,766**				**$ 178,135,471**	**$ 178,050,541**	**$ 178,548,532**	**$ 1,484,162,466**
Churches	$ 1,206,354	$ 1,206,354	$ 164,042	110%		120%	$ 196,850	$ 164,042	$ 196,850	$ 1,403,205
Schools	$ 37,973,021	$ 37,973,169	$ 5,163,636	110%		120%	$ 6,196,363	$ 5,163,656	$ 6,196,387	$ 44,169,384
Large Tire Mfg	$ 4,832,569	$ 4,832,569	$ 657,141	88%	-10%	79%	$ 517,682	$ 657,141	$ 517,682	$ 5,350,251
EV	$ 717,037	$ 717,037	$ 97,504	110%*		110%*	$ 87,331	$ 97,504	$ 87,331	$ 804,368
ICS	$ 1,083,456	$ 1,083,456	$ 147,330	88%	-10%	79%	$ 116,064	$ 147,330	$ 116,064	$ 1,199,519
Special Contracts[1]	$ 33,416,734	$ 34,001,517	$ 4,544,064	96%	-10%	86%	$ 3,908,626	$ 4,623,584	$ 3,977,026	$ 37,325,360
Lighting	$ 27,337,277	$ 27,337,277	$ 3,717,369	88%	-10%	79%	$ 2,928,465	$ 3,717,369	$ 2,928,465	$ 30,265,742
TOTAL	**$ 1,412,593,442**	**$ 1,416,522,760**	**$ 192,086,852**				**$ 192,086,852**	**$ 192,621,167**	**$ 192,568,337**	**$ 1,604,680,294**

Requested Increase-from Rev Model excluding EDR gross-up (Rev Shifts), per Schedule MEM-1 **$ 192,086,852**
Difference in Revenue $ -

RR Reqmt (Request Inc) $192,086,852
EDR Gross-up $ 534,315

Effective Increase Table	Equal Increase	Increase w/ Shifts
LPS/ILP	13.60%	11.70%
LGS*	13.60%	10.72%
MGS	13.60%	10.71%
SGS	13.60%	11.33%
RES/RES DG	13.60%	16.32%
Churches	13.60%	16.32%
Schools	13.60%	16.32%
LTM	13.60%	10.71%
EV*	13.60%	12.18%
ICS	13.60%	10.71%
Special Contracts	13.60%	11.70%
Lighting	13.60%	10.71%

(1) Special Contract rate increases are limited to the percentage increase proposed for the ILP class.
(2) EDR Credits, Net Metering, and Parallel Gen Credit
* Proposed recenue shift Col Q is prior to EV Shortfall shift to Large General Service. Effective change post shortfall is shown in the "Effective Increase Table" to the right.

Comparison of EKC and BCA Proposed Optional TOU Energy Rates for the Large General Service (LGS) Customer Class

Line	Description	LGS Secondary (1)	LGS Primary (2)	LGS Transmission (3)
	EKC Proposed Rates [1]			
1	Summer Peak	$ 0.10079	$ 0.09283	$ 0.10753
2	Summer Off Peak	0.06708	0.06182	0.07163
3	Summer Super Off Peak	0.01890	0.01750	0.02033
4	Winter Off Peak	0.01951	0.01806	0.02098
5	Winter Super Off Peak	0.00597	0.00561	0.00656
	BCA Proposed Rates [2]			
6	Summer Peak	$ 0.09890	$ 0.09613	$ 0.09450
7	Summer Off Peak	0.06586	0.06401	0.06293
8	Summer Super Off Peak	0.01863	0.01811	0.01780
9	Winter Off Peak	0.01923	0.01869	0.01838
10	Winter Super Off Peak	0.00596	0.00579	0.00569
	Difference			
11	Summer Peak	$ (0.00189)	$ 0.00330	$ (0.01303)
12	Summer Off Peak	(0.00122)	0.00219	(0.00870)
13	Summer Super Off Peak	(0.00027)	0.00061	(0.00253)
14	Winter Off Peak	(0.00028)	0.00063	(0.00260)
15	Winter Super Off Peak	(0.00001)	0.00018	(0.00087)

Sources:

[1] Exhibit BDL-1, page 3, Table ES-1

[2] Exhibit BCA-2, page 2

BCA Calculation of Optional TOU Energy Rates
for the Large General Service (LGS) Customer Class

Line	Description	Summer Peak (1)	Summer Off (2)	Summer Super Off (3)	Winter Off (4)	Winter Super Off (5)	Total (6)
	Total $ for Energy Rates[1]						
1	LGS Primary	$ 10,503,034	$ 35,726,113	$ 3,697,791	$ 21,875,903	$ 2,092,886	$ 73,895,728
2	LGS Secondary	$ 3,961,193	$ 13,465,269	$ 1,386,849	$ 8,206,270	$ 773,446	$ 27,793,026
3	LGS Transmission	$ 2,470,450	$ 8,405,837	$ 872,068	$ 5,158,581	$ 496,978	$ 17,403,914
4	Total LGS	$ 16,934,676	$ 57,597,218	$ 5,956,708	$ 35,240,754	$ 3,363,311	$ 119,092,667
	Total kWh[2]						
5	LGS Primary	113,147,755	577,948,758	211,261,094	1,210,966,291	373,182,740	2,486,506,638
6	LGS Secondary	39,300,770	200,744,869	73,379,482	420,617,341	129,621,388	863,663,852
7	LGS Transmission	22,974,206	117,350,221	42,895,734	245,881,939	75,773,287	504,875,387
8	Total LGS	175,422,731	896,043,848	327,536,310	1,877,465,572	578,577,416	3,855,045,876
9	Preliminary Primary Rate	$ 0.096536	$ 0.064279	$ 0.018186	$ 0.018770	$ 0.005813	
	Loss Factor[3]						
10	Primary	4.761%	4.761%	4.761%	4.761%	4.761%	
11	Secondary	7.775%	7.775%	7.775%	7.775%	7.775%	
12	Transmission	3.000%	3.000%	3.000%	3.000%	3.000%	
	Loss Factor Scalar (Compared to Primary)						
13	Secondary	102.88%	102.88%	102.88%	102.88%	102.88%	
14	Transmission	98.32%	98.32%	98.32%	98.32%	98.32%	
15	Secondary Surcharge	$ 0.002777	$ 0.001849	$ 0.000523	$ 0.000540	$ 0.000167	
16	Transmission Credit	$ (0.001623)	$ (0.001081)	$ (0.000306)	$ (0.000316)	$ (0.000098)	
17	Final Primary Rate[4]	$ 0.096127	$ 0.064007	$ 0.018109	$ 0.018691	$ 0.005788	
18	% Difference from Preliminary	-0.42%	-0.42%	-0.42%	-0.42%	-0.42%	
	Final Energy Rates						
19	LGS Primary	$ 0.096127	$ 0.064007	$ 0.018109	$ 0.018691	$ 0.005788	
20	LGS Secondary	$ 0.098904	$ 0.065856	$ 0.018632	$ 0.019231	$ 0.005956	
21	LGS Transmission	$ 0.094504	$ 0.062926	$ 0.017804	$ 0.018375	$ 0.005691	
22	Check: T<P<S	TRUE	TRUE	TRUE	TRUE	TRUE	
	Energy Revenue						
23	Primary Component	$ 10,876,518	$ 36,992,569	$ 3,825,774	$ 22,633,836	$ 2,160,130	76,488,827
24	Secondary Component	$ 3,887,006	$ 13,220,253	$ 1,367,239	$ 8,088,788	$ 771,979	27,335,264
25	Transmission Component	$ 2,171,153	$ 7,384,396	$ 763,695	$ 4,518,130	$ 431,202	15,268,575
26	Total Revenue[5]	$ 16,934,676	$ 57,597,218	$ 5,956,708	$ 35,240,754	$ 3,363,311	119,092,667
27	Check	$ -	$ -	$ -	$ -	$ 0	

Final Check of Revenues

Line	Component	LGS Primary	LGS Secondary	LGS Transmission	Total LGS	Source Note[6]
28	Energy	$ 76,488,827	$ 27,335,264	$ 15,268,575	$ 119,092,667	
29	Demand	$ 19,718,098	$ 7,446,252	$ 4,635,103	$ 31,799,453	Per "3P", Cell Q14
30	Facilities	$ 24,039,655	$ 9,078,224	$ 5,650,965	$ 38,768,844	Per "3P", Cell R16
31	Total Recovery	$ 120,246,580	$ 43,859,740	$ 25,554,644	$ 189,660,964	
32	Total Class RR	$ 118,176,023	$ 44,627,448	$ 27,779,459	$ 190,582,930	Per "3P", Cell AB26
33	Fixed Charge Collection	$ 522,543	$ 309,947	$ 89,477	$ 921,966	Per "3P", Cell AB27
34	Volumetric Recovery	$ 117,653,480	$ 44,317,501	$ 27,689,982	$ 189,660,964	
35	Difference (Vol less Total)	$ 2,593,099	$ (457,761)	$ (2,135,338)	$ -	

Notes:

[1] Sum of L14:L17, M14:M17, etc on the "3P" tab of Witness Lutz's Workpaper, "2024.01.28 C_I Rate Design.xlsx"
[2] Columns T:X on the "3P" tab of Witness Lutz's Workpaper, "2024.01.28 C_I Rate Design.xlsx"
[3] EKC Response to BAI-2-4, "QBAI-2-4 25 KS Central Loss Analysis June 2024.pdf"
[4] Used goal seek to find "Final Primary Rate" in Line 17 by setting "Check" in Line 27 to 0
[5] Total Energy Revenue for each TOU period is equal to the following, where R = Primary Energy Rate:
Secondary kWh x (R + Secondary Surcharge)
+ Primary kWh x R
+ Transmission kWh x (R + Transmission Credit)
[6] Witness Lutz's Workpaper, "2024.01.28 C_I Rate Design.xlsx"

Comparison of EKC and BCA Proposed Optional TOU Energy Rates for the Large Power Service (LPS) Customer Class

Line	Description	LPS Secondary (1)	LPS Primary (2)	LPS Transmission (3)
	EKC Proposed Rates [1]			
1	Summer Peak	$ 0.07580	$ 0.07580	$ 0.09194
2	Summer Off Peak	0.04891	0.04891	0.05932
3	Summer Super Off Peak	0.01353	0.01353	0.01640
4	Winter Off Peak	0.01418	0.01418	0.01718
5	Winter Super Off Peak	0.00451	0.00451	0.00546
	BCA Proposed Rates [2]			
6	Summer Peak	$ 0.08091	$ 0.08091	$ 0.07956
7	Summer Off Peak	0.05220	0.05220	0.05133
8	Summer Super Off Peak	0.01444	0.01444	0.01420
9	Winter Off Peak	0.01513	0.01513	0.01488
10	Winter Super Off Peak	0.00481	0.00481	0.00473
	Difference			
11	Summer Peak	$ 0.00511	$ 0.00511	$ (0.01238)
12	Summer Off Peak	0.00330	0.00330	(0.00798)
13	Summer Super Off Peak	0.00091	0.00091	(0.00220)
14	Winter Off Peak	0.00095	0.00095	(0.00231)
15	Winter Super Off Peak	0.00030	0.00030	(0.00073)

Sources:

[1] Exhibit BDL-1, page 3, Table ES-1

[2] Exhibit BCA-3, page 2

Evergy BCA Calculation of Optional TOU Energy Rates
for the Large Power Service (LPS) Customer Class

Line	Description	Summer Peak (1)	Summer Off (2)	Summer Super Off (3)	Winter Off (4)	Winter Super Off (5)	Total (6)
	Total $ for Energy Rates[1]						
1	LPS Primary	$ 1,449,250	$ 4,986,633	$ 520,520	$ 3,052,898	$ 318,301	$ 10,327,602
2	LPS Secondary	$ -	$ -	$ -	$ -	$ -	$ -
3	LPS Transmission	$ 725,898	$ 2,497,524	$ 260,566	$ 1,528,291	$ 159,112	$ 5,171,390
4	Total LPS	$ 2,175,147	$ 7,484,157	$ 781,086	$ 4,581,188	$ 477,413	$ 15,498,992
	Total kWh[2]						
5	LPS Primary	19,119,524	101,962,213	38,471,138	215,358,069	70,519,142	445,430,086
6	LPS Secondary	-	-	-	-	-	-
7	LPS Transmission	7,895,552	42,106,065	15,886,947	88,933,739	29,121,412	183,943,713
8	Total LPS	27,015,075	144,068,277	54,358,085	304,291,808	99,640,554	629,373,799
9	Preliminary Primary Rate	$ 0.080516	$ 0.051949	$ 0.014369	$ 0.015055	$ 0.004791	
	Loss Factor[3]						
10	Primary	4.761%	4.761%	4.761%	4.761%	4.761%	
11	Secondary	7.775%	7.775%	7.775%	7.775%	7.775%	
12	Transmission	3.000%	3.000%	3.000%	3.000%	3.000%	
	Loss Factor Scalar (Compared to Primary)						
13	Secondary	102.88%	102.88%	102.88%	102.88%	102.88%	
14	Transmission	98.32%	98.32%	98.32%	98.32%	98.32%	
15	Secondary Surcharge	N/A	N/A	N/A	N/A	N/A	
16	Transmission Credit	$ (0.001353)	$ (0.000873)	$ (0.000242)	$ (0.000253)	$ (0.000081)	
17	Final Primary Rate[4]	$ 0.080912	$ 0.052204	$ 0.014440	$ 0.015129	$ 0.004815	
18	% Difference from Preliminary	0.49%	0.49%	0.49%	0.49%	0.49%	
	Final Energy Rates						
19	LPS Primary	$ 0.080912	$ 0.052204	$ 0.014440	$ 0.015129	$ 0.004815	
20	LPS Secondary[5]	$ 0.080912	$ 0.052204	$ 0.014440	$ 0.015129	$ 0.004815	
21	LPS Transmission	$ 0.079558	$ 0.051331	$ 0.014198	$ 0.014876	$ 0.004734	
22	Check: T<P	TRUE	TRUE	TRUE	TRUE	TRUE	
	Energy Revenue						
23	Primary Component	$ 1,546,992	$ 5,322,825	$ 555,518	$ 3,258,198	$ 339,542	11,023,075
24	Secondary Component	$ -	$ -	$ -	$ -	$ -	-
25	Transmission Component	$ 628,156	$ 2,161,332	$ 225,568	$ 1,322,991	$ 137,871	4,475,917
26	Total Revenue[6]	$ 2,175,147	$ 7,484,157	$ 781,086	$ 4,581,188	$ 477,413	15,498,992
27	Check	$ -	$ -	$ -	$ -	$ -	

Final Check of Revenues

Line	Component	LPS Primary	LPS Secondary	LPS Transmission	Total LPS	Source Note[7]
28	Energy	$ 11,023,075	$ -	$ 4,475,917	$ 15,498,992	
29	Demand	$ 2,782,701	$ -	$ 1,393,971	$ 4,176,672	Per "3P", Cell Q14
30	Facilities	$ 3,405,190	$ -	$ 1,705,802	$ 5,110,991	Per "3P", Cell R16
31	Total Recovery	$ 17,210,966	$ -	$ 7,575,690	$ 24,786,656	
32	Total Class RR	$ 16,519,773	$ -	$ 8,275,443	$ 24,795,216	Per "3P", Cell AB26
33	Fixed Charge Collection	$ 4,280	$ -	$ 4,280	$ 8,560	Per "3P", Cell AB27
34	Volumetric Recovery	$ 16,515,493	$ -	$ 8,271,163	$ 24,786,656	
35	Difference (Vol less Total)	$ 695,473	$ -	$ (695,473)	$ -	

Notes:

[1] Sum of L14:L17, M14:M17, etc on the "3P" tab of Witness Lutz's Workpaper, "2024.01.28 C_I Rate Design.xslx"

[2] Columns T:X on the "3P" tab of Witness Lutz's Workpaper, "2024.01.28 C_I Rate Design.xslx"

[3] EKC Response to BAI-2-4, "QBAI-2-4 25 KS Central Loss Analysis June 2024.pdf"

[4] Used goal seek to find "Final Primary Rate" in Line 17 by setting "Check" in Line 27 to 0

[5] Secondary rates are set equal to Primary Rates, as shown in Exhibit BDL-1

[6] Total Energy Revenue for each TOU period is equal to the following, where R = Primary Energy Rate:
Secondary kWh x (R + Secondary Surcharge)
+ Primary kWh x R
+ Transmission kWh x (R + Transmission Credit)

[7] Witness Lutz's Workpaper, "2024.01.28 C_I Rate Design.xslx"

Volume III, 39th Revision, Sheet No. 3.00
Amendment 551

Fuel Adjustment ELECTRIC

A fuel adjustment shall apply to the rate schedules as outlined below.

Rate Schedule	6680-FR-2022 "Reconciliation of Actual Fuel Costs to the Authorized 2022 Fuel Cost Plan"	6680-ER-104 2025 Fuel Cost Plan	Total Fuel Adjustment
Effective Dates	**01/01/2024 through 12/31/2025**	**01/01/2025 through 12/31/2025**	**01/01/2025 through 12/31/2025**
Rg-1, Rg-5, Rd-1, Gs-1, Gs-3, Gd-1, Gs-4, Gw-1, Fw-5. Rw-1, Rw-3, Rw-5, Cg-2 TOD Cp-1, Cp-2, Ms-1, Ms-2, Ms-3 NL-1, Mz-1	$0.004667	$0.001602	$0.006269
CP-2 riders baseline: CPNL, DAMP	$0.004667	$0.001602	$0.006269
CP-2 riders at market: CPNL, DAMP	$0.000000	$0.000000	$0.000000
Rg-1SN 25% Participation	$0.003500	$0.001202	$0.004702
Rg-1SN 50% Participation	$0.002334	$0.000801	$0.003135
Rg-1SN 100% Participation	$0.000000	$0.000000	$0.000000

R

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 2nd Revised SHEET NO. 71.16

CANCELLING MO.P.S.C. SCHEDULE NO. 6 1st Revised SHEET NO. 71.16

APPLYING TO **MISSOURI SERVICE AREA**

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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).

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

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

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

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

RP means the calendar months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage. 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.

*Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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_{RP} is calculated as:

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

Where:

ANEC = FC + PP + E ± R – OSSR

FC = Fuel costs and revenues associated with the Company’s 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.

*Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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.

*Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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) Six and 84/100 percent (6.84%) of transmission service costs reflected in FERC Account 565 and six and 84/100 percent (6.84%) 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:

*Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

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

*Indicates Change.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 2nd Revised SHEET NO. 71.21

CANCELLING MO.P.S.C. SCHEDULE NO. 6 1st Revised SHEET NO. 71.21

APPLYING TO **MISSOURI SERVICE AREA**

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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

*Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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, and (f) 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 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.

*Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

FAR DETERMINATION (Cont'd.)

B = BF x S_{AP}

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company’s most recent rate case. The BF applicable to June through September calendar months (BFSUMMER) is $0.01439 per kWh. The BF applicable to October through May calendar months (BFWINTER) is $0.01328 per kWh.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company’s load settled at its MISO CP node (AMMO.UE or successor node), 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_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) 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.

* Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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 = The lower of (a) PFAR and (b) RAC.

where:

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

FAR_{RP} = FAR Recovery Period rate component calculated to recover under- or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

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

RAC = Rate Adjustment Cap: applies to the FAR rate and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the rate as determined under Section 393.1655.4 by the 2.85% Compound Annual Growth Rate compounded for the amount of time in days that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655, and dividing that result by the weighted average voltage adjustment factor 1.0455%.

* Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

FAR DETERMINATION (Cont'd.)

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

Secondary Voltage Service (VAF_{SEC})	1.0539
Primary Voltage Service (VAF_{PRI})	1.0222
High Voltage Service (VAF_{HV})	1.0059
Transmission Voltage Service (VAF_{TRANS})	0.9928

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

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

FAR_{LPS} = The lesser of (a) the Combined Initial Rate Component for RAC_{LPS} Comparison or (b) RAC_{LPS}.

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

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

The Weighting Factors are the ratios between each voltage's annual kWh and total annual LPS kWh. The above Combined Initial Rate Component is developed for the purposes of determining if the statutory RAC_{LPS} has been exceeded, and if it has, calculating the FAR Shortfall Adder to be applied across all non-LPS service classifications in the immediately concluded AP.

* Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

Where the Combined Initial Rate Component for RAC_{LPS} Comparison is greater than FAR_{LPS}, then a Per kWh FAR Shortfall Adder shall apply to each of the respective Initial Rate Components to be determined as follows:

Per kWh FAR Shortfall Adder = (((Combined Initial Rate Component For RAC_{LPS} Comparison – FAR_{LPS}) x SLPS) / (SRP – SRP - LPS))

Where:

SLPS = Estimated Recovery Period LPS kWh sales at the retail meter

SRP-LPS = Estimated Recovery Period LPS kwh sales at the Company’s MISO CP Node (AMMO.UE or successor node)

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

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

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

FARHV = Initial Rate Component For High Voltage Customers + (Per kWh FAR Shortfall Adder x VAFHV)

FARTRANS = Initial Rate Component For Transmission Customers + (Per kWh FAR Shortfall Adder x VAFTRANS)

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

LPSFARPRI = Initial Rate Component For Primary Customers x LPS RAC Cap Multiplier

LPSFARHV = Initial Rate Component For High Voltage Customers x LPS RAC Cap Multiplier

LPSFARTRANS = Initial Rate Component For Transmission Customers x LPS RAC Cap Multiplier

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

The FAR applicable to the individual Service Classifications, including the calculations on Lines 24 through 29 of Rider FAC, shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

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

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

* Indicates Change.

RIDER FAC

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

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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.

* Indicates Change.

UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6 2nd Revised SHEET NO. 71.28

CANCELLING MO.P.S.C. SCHEDULE NO. 6 1st Revised SHEET NO. 71.28

APPLYING TO MISSOURI SERVICE AREA

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

FAC CHARGE TYPE TABLE

* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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

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

MISO Transmission Service Settlement Schedules

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

* Indicates Change.

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 Chairman & President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6	2nd Revised	SHEET NO.	71.29
CANCELLING MO.P.S.C. SCHEDULE NO. 6	1st Revised	SHEET NO.	71.29

APPLYING TO **MISSOURI SERVICE AREA**

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

FAC CHARGE TYPE TABLE (Cont'd.)
* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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

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

PJM Market Settlement Charge Types

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

PJM Transmission Service Charge Types

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

*Indicates Change.

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

FAC CHARGE TYPE TABLE (Cont'd.)
* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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

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

SPP Market Settlement Charge Types

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

* Indicates Change.

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

FAC CHARGE TYPE TABLE (Cont'd.)
* **(Applicable To Service Provided Between July 9, 2023 And The Day Before The Effective Date Of This Tariff)**

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;

* Indicates Change.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 6th Revised SHEET NO. 71.32

CANCELLING MO.P.S.C. SCHEDULE NO. 6 5th Revised SHEET NO. 71.32

APPLYING TO **MISSOURI SERVICE AREA**

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

(Applicable To services provided on June 1, 2025 through September 30, 2025)

Calculation of Current Fuel Adjustment Rate (FAR):

	Accumulation Period Ending:		January 31, 2025
1.	Actual Net Energy Cost = (ANEC) (FC+PP+E+R -OSSR)		$193,849,340
2.	(B) = (BF x S_{AP})	-	$143,155,882
	2.1 Base Factor (BF)		$.01328/kWh
	2.2 Accumulation Period Sales (S_{AP})		10,779,810,352 kWh
3.	Total Company Fuel and Purchased Power Difference	=	$50,693,458
	3.1 Customer Responsibility	x	95%
4.	Fuel and Purchased Power Amount to be Recovered	=	$48,158,786
	4.1 Interest (I)	-	$4,811,937
	4.2 True-Up Amount (TUP)	+	$(2,032,084)
	4.3 Prudence Adjustment Amount (P)	±	$0
5.	Fuel and Purchased Power Adjustment (FPA)	=	$50,938,639
6.	Estimated Recovery Period Sales (S_{RP})	÷	22,425,313,714 kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$0.00227/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$0.00114/kWh
9.	Preliminary Fuel Adjustment Rate (PFAR)	=	$0.00341/kWh
10.	Rate Adjustment Cap (RAC)	=	N/A
11.	Fuel Adjustment Rate (FAR, lesser of PFAR and RAC)	=	$0.00341/kWh

Initial Rate Component for the Individual Service Classifications

12.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0539
13.	Initial Rate Component for Secondary Customers	=	$0.00360/kWh
14.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0222
15.	Initial Rate Component for Primary Customers	=	$0.00349/kWh
16.	Primary LPS Weighting Factor (WF_{PRI})		.1587
17.	High Voltage Adjustment Factor (VAF_{HV})		1.0059
18.	Initial Rate Component for High Voltage Customers	=	$0.00343/kWh
19.	High Voltage LPS Weighting Factor (WF_{HV})		.3967
20.	Transmission Adjustment Factor (VAF_{TRANS})		0.9928
21.	Initial Rate Component for Transmission Customers	=	$0.00339/kWh
22.	Transmission Voltage LPS Weighting Factor (WF_{TRANS})		.4446
23.	Combined Initial Rate Component for RAC_{LPS} Comparison	=	$0.00342/kWh

LPS Rate Adjustment Cap Components & Adder

24.	RAC_{LPS}	=	N/A
25.	Weighted Avg FAR for Large Primary Service (FAR_{LPS}, lesser of 23 and 24)	=	$0.00342/kWh
26.	Difference (Line 23 – Line 25) if applicable	=	$0.00000/kWh
27.	Estimated Recovery Period Metered Sales for LPS (S_{LPS})	=	2,590,895,290 kWh
28.	FAR Shortfall Adder (Line 26 x Line 27)	=	$0
29.	Per kWh FAR Shortfall Adder (Line 28 / (S_{RP} – SRP_{LPS})	=	$0.00000/kWh

FAR Applicable to the Non-LPS Service Classifications

30.	FAR for Secondary(FAR_{SEC})	(Line 13 + (Line 29 x Line 12))	=	$0.00360/kWh
31.	FAR for Primary(FAR_{PRI})	(Line 15 + (Line 29 x Line 14))	=	$0.00349/kWh
32.	FAR for High Voltage(FAR_{HV})	(Line 18 + (Line 29 x Line 17))	=	$0.00343/kWh
33.	FAR for Tramsmission(FAR_{TRANS})	(Line 21 + (Line 29 x Line 20))	=	$0.00339/kWh

FAR Applicable to the LPS Service Classifications

34.	LPS RAC Cap Multiplier (Line 25 / Line 23))		=	1.0
35.	FAR for LPS Primary($LPSFAR_{PRI}$)	(Line 15 x Line 34)	=	$0.00349/kWh
36.	FAR for LPS High Voltage($LPSFAR_{HV}$)	(Line 18 x Line 34)	=	$0.00343/kWh
37.	FAR for LPS Transmission($LPSFAR_{TRANS}$)	(Line 21 x Line 34)	=	$0.00339/kWh

DATE OF ISSUE April 1, 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
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).

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

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

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

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

RP means the calendar months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage. 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.

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_{RP} is calculated as:

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

Where:

ANEC = FC + PP + E ± R − OSSR

FC = Fuel costs and revenues associated with the Company's 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.

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.

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) Ten and 73/100 percent (10.73%) of transmission service costs reflected in FERC Account 565 and ten and 73/100 percent (10.73%) 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:

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_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

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

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

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.)

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, and (f) 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 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.

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_{AP}

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company’s most recent rate case. The BF applicable to June through September calendar months (BFSUMMER) is $0.01421 per kWh. The BF applicable to October through May calendar months (BFWINTER) is $0.01383 per kWh.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company’s load settled at its MISO CP node (AMMO.UE or successor node), 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_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) 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.

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_{RP} = FAR Recovery Period rate component calculated to recover under- or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

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_{SEC})	1.0560
Primary Voltage Service (VAF_{PRI})	1.0240
High Voltage Service (VAF_{HV})	1.0060
Transmission Voltage Service (VAF_{TRANS})	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.

RIDER FAC

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

GENERAL RATE CASE/PRUDENCE REVIEWS

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

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

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

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

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

MISO Transmission Service Settlement Schedules

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

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

PJM Market Settlement Charge Types

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

PJM Transmission Service Charge Types

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

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

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

SPP Market Settlement Charge Types

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

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)

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;

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To services provided on XXXXXX through XXXXXX)

Calculation of Current Fuel Adjustment Rate (FAR):

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

FAR Applicable to the Individual Service Classifications

10.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0560
11.	Rate for Secondary Customers	=	\$0.00000/kWh
12.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0240
13.	Rate for Primary Customers	=	\$0.00000/kWh
14.	High Voltage Adjustment Factor (VAF_{HV})		1.0060
15.	Rate for High Voltage Customers	=	\$0.00000/kWh
16.	Transmission Adjustment Factor (VAF_{TRANS})		0.9931
17.	Rate for Transmission Customers	=	\$0.00000/kWh

ARKANSAS PUBLIC SERVICE COMMISSION

2nd Revised	Sheet No. 38.1	Schedule Sheet 1 of 8 Including Attachment	
Replacing: 1st Revised	Sheet No. 38.1		
Entergy Arkansas, LLC Name of Company			
Kind of Service: Electric	Class of Service: All		Docket No.: 22-082-U Order No.: 8
Part III. Rate Schedule No. 38			Effective: 11/1/23
Title: Energy Cost Recovery Rider (ECR)			PSC File Mark Only

38.1. RECOVERY OF ENERGY COST

Energy Cost Recovery Rider ECR ("Rider ECR") defines the procedure by which the "Energy Cost Rate" of Entergy Arkansas, LLC ("EAL" or "Company") shall be initially established and periodically redetermined. The Energy Cost Rate shall recover the Company's net fuel and purchased energy cost, as defined in this Rider ECR ("Energy Cost").

38.2. ENERGY COST RATE

The Energy Cost Rate to be initially effective under this Rider ECR shall be determined in the manner approved by the Arkansas Public Service Commission ("Commission") in Docket No. 15-015-U, Order No. 18 and shall become effective upon the date established by the Commission. The Energy Cost Rate shall then be redetermined annually through filings to be made in accordance with the provisions of § 38.3 of this Rider ECR.

The Energy Cost Rate shall be applied to each customer's monthly billing energy (kWh), except that the Energy Cost Rate shall not apply to a special rate contract unless such contract includes specific provisions related to the recovery of the Company's Energy Cost.

Net benefits achieved pursuant to the Stuttgart Solar and Chicot Solar power purchase agreements ("PPAs") and any corresponding additional sum shall be determined in the manner approved by the Commission in Order No. 5 in Docket No. 15-014-U and Order No. 4 in Docket No. 17-041-U, respectively.

As approved by the Commission's Order No. 7 in Docket No. 22-082-U, the additional sums associated with the Flat Fork and Forgeview PPAs shall be determined pursuant to the commensurate return methodology pursuant to Ark. Code Ann. § 23-18-109(e)(2)(B).

38.3. ANNUAL REDETERMINATION

On or before March 15 of each year beginning in 2014, the Company shall file a redetermined Energy Cost Rate with the Commission. The redetermined Energy Cost Rate shall be determined by application of the Energy Cost Rate Formula set out in Attachment A to this Rider ECR. Each such revised Energy Cost Rate shall be filed in the proper underlying docket and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the revised Energy Cost Rate.

The redetermined Energy Cost Rate shall reflect the projected Energy Cost for the 12-month period commencing on April 1 of each year ("Projected Energy Cost Period") together with a true-up adjustment reflecting the over-recovery or under-recovery of the Energy Cost for the 12-month period ended December 31 of the prior calendar year

ARKANSAS PUBLIC SERVICE COMMISSION

1st Revised	Sheet No. 38.2	Schedule Sheet 2 of 8 Including Attachment	
Replacing: Original	Sheet No. 38.2		
Entergy Arkansas, LLC Name of Company			
Kind of Service: Electric	Class of Service: All		Docket No.: 22-082-U Order No.: 8
Part III. Rate Schedule No. 38			Effective: 11/1/23
Title: Energy Cost Recovery Rider (ECR)			PSC File Mark Only

("Energy Cost Period"). The Energy Cost Rate so redetermined shall be effective for bills rendered on and after the first billing cycle of April of the filing year and shall then remain in effect for twelve (12) months ("Rider Cycle"), except as otherwise provided for below.

The annual update shall include the reporting requirements as ordered by the Commission Order No. 10 in Docket No. 06-101-U and modified by Order No. 21 in Docket No. 13-028-U.

38.4. INTERIM ADJUSTMENT

Should a cumulative over-recovery or under-recovery balance arise during any Rider Cycle which exceeds ten (10) percent of the Energy Cost determined for the Energy Cost Period included in the most recently filed rate redetermination under this Rider ECR, then either the Arkansas Public Service Commission General Staff or the Company may propose an interim revision to the then currently effective Energy Cost Rate.

38.5. TERM

This Rider ECR shall remain in effect subject to eighteen months advance notice of termination by the Commission following notice and hearing.

ENERGY COST RATE FORMULA

ECR = ENERGY COST RATE

ECR = (TUA + (PEC*EAF)+AS) / PES

WHERE,

TUA = TRUE-UP ADJUSTMENT FOR THE ENERGY COST PERIOD INCLUDING CARRYING CHARGES (1)(3)

$$TUA = \sum_{j=1}^{12} (EC*EAF - RR_j) + (((BB_j + EB_j)/2) * (CCR/12))$$

WHERE,

EC_j = ENERGY COST FOR MONTH *j* OF THE ENERGY COST PERIOD

EC_j = $FE_j + PE_j + RSC_j + SEPO_j + TEP_j + GP_j + GZ_j$

WHERE,

FE_j = FUEL EXPENSE CHARGED TO ACCOUNTS 501, 518, AND 547 IN MONTH *j* OF THE ENERGY COST PERIOD.

PE_j = PURCHASED ENERGY EXPENSE CHARGED TO ACCOUNT 555 (6) (7) OR CREDITED TO ACCOUNT 447 IN MONTH *j* OF THE ENERGY COST PERIOD (8), BUT EXCLUDING THE RETAINED SHARE PORTION OF GRAND GULF FUEL (9) CHARGES.

RSC_j = GRAND GULF RETAINED SHARE ENERGY CHARGE IN MONTH *j* OF THE ENERGY COST PERIOD (2)

$SEPO_j$ = NET COSTS AND CREDITS BILLED THROUGH THE SOLAR ENERGY PURCHASE OPTION

TEP_j = NET GAIN OR LOSS FROM EAL'S INTEREST IN SOLAR ASSET TAX EQUITY PARTNERSHIP

GP_j = NET COSTS AND CREDITS BILLED THROUGH THE GREEN PROMISE

GZ_j = NET COSTS AND CREDITS BILLED THROUGH THE GO ZERO

ENERGY COST RATE FORMULA (CONT'D)

RR_j = REVENUE UNDER RIDER ECR FOR MONTH *j* OF THE ENERGY COST PERIOD EXCLUDING ANY REVENUES ASSOCIATED WITH THE ADDITIONAL SUM AS APPROVED BY THE COMMISSION PURSUANT TO ACT 1088 OF 2015 PLUS AN IMPUTED LEVEL OF REVENUES FOR SALES UNDER SPECIAL RATE CONTRACTS WHERE THE ENERGY COST RATE IS NOT SEPARATELY BILLED

BB_j = BEGINNING CUMULATIVE OVER(UNDER)-RECOVERY BALANCE FOR MONTH *j* (Excluding carrying charges)

EB_j = ENDING CUMULATIVE OVER(UNDER)-RECOVERY BALANCE FOR MONTH *j* (Excluding carrying charges)

CCR = CARRYING CHARGE RATE (3)

PEC = PROJECTED ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (4)

$$PEC = \sum_{j=1}^{12} EC_j + NRFA \qquad (5)$$

WHERE,

EC_j = ENERGY COST FOR MONTH *j* OF THE ENERGY COST PERIOD (1)

NRFA = NUCLEAR REFUELING OUTAGE ADJUSTMENT

NRFA = GACR * (RHD1 * CAP1 + RHD2 * CAP2 + RHDGG * CAPGG)

ENERGY COST RATE FORMULA (CONT'D)

WHERE,

GACR = ANNUAL AVERAGE AVOIDED ENERGY COST RATE ($/kWh) AT GENERATION LEVEL FOR THE ENERGY COST PERIOD AS SET OUT IN THE MOST RECENT FILING WITH THE COMMISSION PURSUANT TO SMALL COGENERATION RIDER SCR OR ANY SUPERSEDING RATE SCHEDULE

RHD1 = INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS FOR ANO UNIT 1 BETWEEN THE ENERGY COST PERIOD AND THE PROJECTED ENERGY COST PERIOD

CAP1 = NET CAPABILITY (kW) OF ANO UNIT 1 AT THE END OF THE ENERGY COST PERIOD THAT IS AVAILABLE TO THE COMPANY'S RETAIL CUSTOMERS

RHD2 = INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS FOR ANO UNIT 2 BETWEEN THE ENERGY COST PERIOD AND THE PROJECTED ENERGY COST PERIOD

CAP2 = NET CAPABILITY (kW) OF ANO UNIT 2 AT THE END OF THE ENERGY COST PERIOD THAT IS AVAILABLE TO THE COMPANY'S RETAIL CUSTOMERS

RHDGG = INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS FOR GRAND GULF BETWEEN THE ENERGY COST PERIOD AND THE PROJECTED ENERGY COST PERIOD

CAPGG = NET CAPABILITY (kW) OF EAL'S ALLOCATED SHARE OF GRAND GULF AT THE END OF THE ENERGY COST PERIOD AS REDUCED BY THE RETAINED SHARE AND THAT IS AVAILABLE TO THE COMPANY'S RETAIL CUSTOMERS

EAF = ENERGY ALLOCATION FACTOR BASED ON PRODUCTION ENERGY FOR THE RETAIL JURISDICTION FOR THE ENERGY COST PERIOD (1)

PES = PROJECTED SALES (kWh) SUBJECT TO THIS RIDER ECR FOR THE PROJECTED ENERGY COST PERIOD

ENERGY COST RATE FORMULA (CONT'D)

AS = ADDITIONAL SUMS FOR STUTTGART SOLAR AND CHICOT SOLAR TO BE CALCULATED SEPARATELY AND THEN SUMMED, WITH EACH BEING BASED ON ACTUAL CUMULATIVE NET BENEFITS CALCULATED ON THE ACTUAL ANNUAL SAVINGS FORMULA APPROVED, RESPECTIVELY, IN ORDER NO. 5 IN DOCKET NO. 15-014-U FOR STUTTART SOLAR AND AS DIRECTED IN ORDER NO. 4 IN DOCKET NO. 17-0471-U FOR CHICOT SOLAR.

ACTUAL ANNUAL SAVINGS = MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. (MISO) NET ANNUAL SETTLEMENTS RECEIVED OR PAID BY EAL RELATED TO THE STUTTGART SOLAR AND CHICOT SOLAR PPAS PLUS REVENUES FROM THE SALE OF ENVIRONMENTAL ATTRIBUTES RELATED TO THE STUTTGART SOLAR AND CHICOT SOLAR PPAS AND LIQUIDATED DAMAGES PAID PURSUANT TO THE PPAS LESS THE SUM OF THE NET ANNUAL PAYMENTS MADE BY EAL TO STUTTGART SOLAR AND CHICOT SOLAR PURSUANT TO THE SOLAR PPAS AND THE ANNUAL AMORTIZATION OF THE UPFRONT PAYMENT OF THE STUTTGART SOLAR PPA. (10) (11)

FOR EACH RESPECTIVE PPA, IF THE ACTUAL ANNUAL SAVINGS ARE NEGATIVE, NO SHARING WOULD OCCUR, AND THE NEGATIVE NET SAVINGS WILL BE ACCRUED AND DEDUCTED FROM ANY POSITIVE SAVINGS IN FUTURE YEARS (10);

FOR EACH RESPECTIVE PPA, IF THERE IS A REMAINING POSITIVE ACTUAL ANNUAL SAVINGS BALANCE AFTER DEDUCTING ANY ACCUMULATED NEGATIVE NET SAVINGS, THEN AN ADDITIONAL SUM WOULD BE CALCULATED AS 20 PERCENT TIMES ACTUAL ANNUAL SAVINGS.

AND

ADDITIONAL SUMS FOR FLAT FORK SOLAR AND FORGEVIEW SOLAR TO BE CALCULATED SEPARATELY AND THEN SUMMED, WITH EACH BEING BASED ON A COMMENSURATE RETURN ON THE POWER PURCHASE AGREEMENT AS WOULD BE ALLOWED FOR AN EQUIVALENT INVESTMENT IN A POWER PLANT FORMULA APPROVED IN ORDER NO. 7 IN DOCKET NO. 22-082-U.

COMMENSURATE RETURN = (PPA PRICE * ANNUAL OUTPUT OF FACILITY) * APPLICABLE 12-MONTH AVERAGE OF THE DAILY US TREASURY PAR YIELD CURVE RATES

ENERGY COST RATE FORMULA (CONT'D)

WHERE,

PPA PRICE	=	PPA PRICE PER MWH FOR THE ENERGY COST PERIOD
12-MONTH AVERAGE OF THE DAILY US TREASURY PAR YIELD CURVE RATES	=	FOR PPAS HAVING A 20-YEAR TERM, THE 12-MONTH AVERAGE OF THE DAILY 20-YEAR US TREASURY PAR YIELD CURVE RATE FOR THE ENERGY COST PERIOD. FOR PPAS HAVING A 15-YEAR TERM, AN AVERAGE OF THE 12-MONTH AVERAGE OF THE DAILY 20-YEAR AND 10-YEAR US TREASURY PAR YIELD CURVE RATES FOR THE ENERGY COST PERIOD.
ANNUAL OUTPUT OF FACILITY	=	ENERGY PRODUCTION (MWH) FOR THE ENERGY COST PERIOD.

ENERGY COST RATE FORMULA (CONT'D)

NOTE:

1) The Energy Cost Period is the calendar year immediately preceding the filing year.
2) RSC_j is to be determined by multiplying the Grand Gulf Retained Share energy (kWh) supplied to the Company's retail customers in each month by the annual average avoided energy cost rate ($/kWh) at generation level most recently filed with the Commission pursuant to Small Cogeneration Rider SCR or any superseding rate schedule.
3) Monthly carrying charges shall be calculated on the average beginning and ending over(under)-recovery balances, excluding carrying charges, using the Commission approved customer deposit simple interest rate for the period.
4) The Projected Energy Cost Period is the twelve-month period commencing on April 1 of the filing year.
5) Should there be unusual circumstances associated with any Projected Cost Period either the Company or the Staff may propose use of a Projected Energy Cost (Variable PEC) different from that defined by this formula.
6) PE_j shall include energy costs associated with long-term renewable energy resources recorded in FERC Account 555 when approved by the Commission prior to inclusion in this Rider ECR.
7) PE_j shall include the annual amortization of the upfront payment of the Stuttgart Solar PPA calculated on a straight-line basis over the term of the PPA.
8) PE_j shall include the credits from the sale of renewable energy credits from the Stuttgart Solar and Chicot Solar PPAs and credits related to the damages under the terms of the Stuttgart Solar and Chicot Solar PPAs.
9) PE_j shall exclude FERC-Ordered System Agreement payments/receipts.
10) The Carrying Charge Rate shall be the authorized rate of return on rate base most recently approved for EAL by the Commission and shall be applied to the cumulative net benefits balance.
11) As referenced in this provision, net annual payments made by EAL to Stuttgart Solar and Chicot Solar are not net of liquidated damage payments that are accounted for elsewhere in the formula.

ARKANSAS PUBLIC SERVICE COMMISSION

4th Revised | Sheet No. 18.1 | Schedule Sheet 1 of 2

Replacing: 3rd Revised | Sheet No. 18.1

Entergy Arkansas, LLC
Name of Company

Kind of Service: Electric | Class of Service: Commercial/Industrial

Docket No.: 16-036-FR
Order No.: 62
Effective: 1/2/24

Part IV. Rate Schedule No. 18

Title: Voltage Adjustment Rider (VAR)

PSC File Mark Only

18.0. VOLTAGE ADJUSTMENT RIDER

18.1. AVAILABILITY

Available at the option of the Company to a customer receiving electric service under Rate Schedules No. 4, Small General Service, No. 6, Large General Service, No. 7, Large General Service Time-of-Use, No. 8, Large Power Service, No. 9, Large Power Service Time-of-Use, No. 20, Standby Service Rider, or No. 69, Large Power High Load Density Service where such service is delivered and/or metered at voltages of 13,800Y/7,960 or greater.

18.2. ADJUSTMENT TO NET MONTHLY RATE

The Demand, Energy and the highest kW Demand, or ratchet Demand, in the Minimum provision of the service schedule are reduced by the percentage reductions below but the demand charge in the Minimum provision of the service schedule is not reduced by the $/kW reduction. The minimum Demand defined in the Demand provision of the service schedule is not reduced by the percentage reductions below.

In this schedule secondary voltages are those less than 13,800Y/7,960 Volts, primary voltages are those 13,800Y/7,960 Volts or greater but less than 69,000 Volts and transmission voltages are those 69,000 Volts or greater.

18.2.1. Service is delivered and metered at secondary voltage.

Billing Item	Rate
No reductions:	0.0%

18.2.2. Service is delivered at secondary voltage but metered at primary voltage.

Billing Item	Rate
Reduce Demand and Energy for losses by:	1.0%

18.2.3. Service is delivered at primary voltage but metered at secondary voltage and customer owns and maintains all transformation facilities.

Billing Item	Rate
Reduce Monthly Demand Charge per kW by:	$ 2.18
Reduce Daily Demand Charge per kW by:	$ 0.0717

ARKANSAS PUBLIC SERVICE COMMISSION

3rd Revised Sheet No. 18.2 Schedule Sheet 2 of 2

Replacing: 2nd Revised Sheet No. 18.2

Entergy Arkansas, LLC
Name of Company

Kind of Service: Electric Class of Service: Commercial/Industrial

Docket No.: 16-036-FR
Order No.: 62
Effective: 1/2/24

Part IV. Rate Schedule No. 18

PSC File Mark Only

Title: Voltage Adjustment Rider (VAR)

18.2.4. Service is delivered and metered at primary voltage and customer owns and maintains all transformation facilities.

Billing Item	Rate
Reduce Demand and Energy for losses by:	1.0%
Reduce Monthly Demand Charge per kW by:	$ 2.18
Reduce Daily Demand Charge per kW by:	$ 0.0717

18.2.5. Service is delivered at transmission voltage but metered at primary voltage.

Billing Item	Rate
Reduce Demand and Energy for losses by:	1.0%
Reduce Monthly Demand Charge per kW by:	$ 4.66
Reduce Daily Demand Charge per kW by:	$ 0.1532

18.2.6. Service is delivered and metered at transmission voltage.

Billing Item	Rate
Reduce Demand and Energy for losses by:	2.0%
Reduce Monthly Demand Charge per kW by:	$ 4.66
Reduce Daily Demand Charge per kW by:	$ 0.1532

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL — SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 1

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) — which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

APPLICABILITY

To all bills rendered by Company (Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. Company) for utility service, permitting recovery of fuel cost.

BASIS FOR ADJUSTMENT

A Retail Energy Cost Adjustment (RECA) shall be added to a customer's bill by multiplying the number of kilowatt-hours delivered over the billing month by a RECA Factor determined by the following formula:

RECA Factor = FA

The FA (Fuel Adjustment) component of the RECA Factor shall be calculated quarterly as follows:

$$FA = \frac{(F_P + P_P + E_P + EC_P - NRCA_P)}{(.01) \times S_P} + ACAF_P$$

Where:

F_P = Projected cost of fuel expense shall explicitly include the fuel stock initially recorded in Account 151 (Fuel Stock) or Account 120 (Nuclear Fuel), assemblies in reactor plus materials and supplies initially charged to Account 154 (Plant Materials and Supplies) consumed with the fuel and related to energy production or reducing air emissions permitting the generation of energy plus fuel, and other expenses directly charged to Accounts 501 (Fuel), 518 (Nuclear Fuel Expense), 547 (Fuel), 559.3 (Fuel), and 577.3 (Storage Fuel). Explicitly excluded from projected fuel cost is any internal labor charge to Accounts 501, 518, 547, 559.3, and 577.3.

P_P = Projected cost of purchased power to be incurred associated with energy delivered to customers over a billing quarter. The following projected components shall be included in the purchased power calculation:

- Purchased power costs, including those paid to renewable generators, recorded as purchased energy costs to Account 555, inclusive of long-term (over 365 days) capacity charges for capacity purchases which are contracted after December 21, 2023, and all short-term capacity purchases of one year or less (365 days) in duration.

Issued	November	1	2024
	Month	Day	Year
Effective	January	1	2025
	Month	Day	Year

By ____________

Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 2

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

RETAIL ENERGY COST ADJUSTMENT

- Revenue received from the sale of power to third parties (including the SPP) recorded in Account 447.
- Long-term (over 365 days) capacity revenues for capacity sales which are contracted after December 21, 2023, and all short-term capacity revenues of one year or less (365 days) in duration and recorded in Account 447.
- Other payments made to renewable generators to curtail production when economical to do so and recorded in Account 555.
- "Other SPP Charges and Credits" ("Other SPP Charges and Credits" are specifically listed below, along with the anticipated FERC accounts that they will be recorded to, in Note 11 to the tariff).
- Virtual Energy Transactions and Fees for legitimate hedging purposes, as discussed in Note 12 to the tariff below.
- Hedging Transactions as discussed in Note 15 to the tariff below.
- Purchases and sales of energy outside of SPP recorded in Accounts 426 and 421, respectively.
- Transmission expense inside or outside of SPP necessary to make purchases and sales outside of SPP, which is not otherwise recovered through Evergy Kansas Central's Transmission Formula Rate or Transmission Delivery Charge, and recorded to Account 565.

E_P = The projected emission allowance costs to be recorded in Account 509 and gains or losses of emission allowances to be recorded in Account 411.8 or Account 411.9, respectively, during the billing quarter.

EC_P = The projected revenues from environmental credits to be recorded in Account 411.11 (Gains from Disposition of Environmental Credits) and Account 411.12 (Losses from Disposition of Environmental Credits) during the billing quarter. The projected costs from environmental credits to be recorded in Account 555.2 (Bundled Environmental Credits) and Account 555.3 (Unbundled Environmental Credits), as defined by FERC, during the billing quarter.

$NRCA_P$ = Projected cost to achieve sales to Company's Non-Requirements Customers during the billing quarter.

S_P = Projected kWhs to be delivered to all Company's Requirements Customers during the billing quarter.

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

ANJ

Index ____________________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL

(Name of Issuing Utility)

SCHEDULE RECA

Replacing Schedule RECA Sheet 3

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable)

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 3 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

Requirements Customers = Retail customers of Company plus wholesale customers with agreements with a fuel clause and an initial term of 10 years or longer that provide for the explicit recovery of system average fuel expense.

Non-Requirements Customers = Wholesale customers taking service on a contract basis with an initial term of one year or longer. These customers include participation power sales contracts, and contracts with cooperatives and municipal utilities not subject to a fuel clause. Non-Requirements Customers are also customers taking service under the Solar kW tariff for that part of their service purchased under that tariff.

Note: All quarterly projected costs and sales will be derived from a production costing simulation model. Outputs from the model will include the projected costs of fuel and purchased power, and projected costs to achieve non-requirements sales. Actual costs and sales for NRCA will be derived from a production costing simulation model using actual inputs for the quarter.

The $ACAF_P$ (Projected Annual Correction Adjustment Factor) shall be calculated as follows:

$$ACAF_P = \frac{(F_A + P_A + E_A + EC_A - NRCA_A - FAR_A \pm WR + WPWF_E - WPWF_D) + ACAB}{(.01) \times S_A}$$

Where:

F_A = Actual cost of fuel expense shall explicitly include the fuel stock initially recorded in Account 151 (Fuel Stock) or Account 120 (Nuclear Fuel), assemblies in reactor plus materials and supplies initially charged to Account 154 (Plant Materials and Supplies) consumed with the fuel and related to energy production or reducing air emissions permitting the generation of energy plus fuel, and other expenses directly charged to Accounts 501 (Fuel), 518 (Nuclear Fuel Expense), 547 (Fuel), 559.3 (Fuel), and 577.3 (Storage Fuel). Explicitly excluded from projected fuel cost is any internal labor charge to Accounts 501, 518, 547, 559.3, and 577.3.

P_A = Actual cost of purchased power incurred during the previous ACA year. The following components shall be included in the purchased power calculation:

Issued	November	1	2024
	Month	Day	Year
Effective	January	1	2025
	Month	Day	Year

By

Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 4

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon. Sheet 4 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

- Purchased power costs, including those paid to renewable generators, recorded as purchased energy costs to Account 555, inclusive of long-term (over 365 days) capacity charges for capacity purchases which are contracted after December 21, 2023, and all short-term capacity purchases of one year or less (365 days) in duration.
- Revenue received from the sale of power to third parties (including the SPP) recorded in Account 447.
- Long-Term (over 365 days) capacity revenues for capacity sales which are contracted after December 21, 2023, and all short-term capacity revenues of one year or less (365 days) in duration and recorded in Account 447.
- Other payments made to renewable generators to curtail production when economical to do so and recorded in Account 555.
- “Other SPP Charges and Credits” (“Other SPP Charges and Credits” are specifically listed below in Note 11 to the tariff).
- Virtual Energy Transactions and Fees for legitimate hedging purposes, as discussed in Note 12 to the tariff below.
- Hedging Transactions as discussed in Note 15 to the tariff below.
- Purchases and sales of energy outside of SPP recorded in Accounts 426 and 421, respectively.
- Transmission expense inside or outside of SPP necessary to make purchases and Sales outside of SPP, which is not otherwise recovered through Evergy Kansas Central’s Transmission Formula Rate or Transmission Delivery Charge, and recorded to Account 565.

In addition, the revenue received from the Renewable Energy Program Rider shall be credited as an offset to purchased power.

E_A = The actual emission allowance costs recorded in Account 509 and gains or losses of emission allowances recorded in Account 411.8 or Account 411.9, respectively, during the previous ACA year.

EC_A = The actual revenues from environmental credits recorded in Account 411.11 (Gains from Disposition of Environmental Credits) and Account 411.12 (Losses from Disposition of Environmental Credits) during the previous ACA year. The costs from actual environmental credits recorded in Account 555.2 (Bundled Environmental Credits) and Account 555.3 (Unbundled Environmental Credits), as defined by FERC, during the previous ACA year.

Issued	November	1	2024
	Month	Day	Year
Effective	January	1	2025
	Month	Day	Year

By ____________

Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL — SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 5

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) — which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 5 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

$NRCA_A$ = The calculated actual cost to achieve sales to Company's Non-Requirements Customers during the previous ACA year.

FAR_A = The actual Fuel Adjustment revenue for the previous ACA year.

WR = The difference (increase or decrease) between wholesale Requirements Customers' non-fuel revenue being credited to base rates as set in the most recent base rate proceeding (the non-fuel base line revenue) and the actual non-fuel revenue received by Company in the ACA year. This difference will be (refunded)/recovered in the ACAF.

$WPWF_E$= The three-year rolling average of actual MWh production of Western Plains Wind Farm greater than 1,193,878 MWh's beginning with the three-year average period ending December 2020, multiplied by $20.70/MWh.

$WPWF_D$= The three-year rolling average of actual MWh production of Western Plains Wind Farm less than 1,095,556 MWh's beginning with the three-year average period ending December 2020, multiplied by $20.70/MWh.

$ACAB_A$ = Actual ACA balance from the previous ACA year.

S_A = Actual kWhs delivered to all Company's Requirements Customers during the previous ACA year.

ACA year = The ACA year shall begin with the delivery of energy during the first billing cycle of January and ending with the last billing cycle in December of each year. Modifications to ACAFs shall be implemented in first billing cycle of the second quarter of each year.

NOTES TO THE TARIFF:

1. The adjustment factor will be expressed in cents per kilowatt-hour rounded to the nearest one-thousandth of a cent.

2. The references to Accounts within the RECA tariff are as defined in the FERC Uniform System of Accounts.

3. The FA component of the RECA Factor will be computed quarterly.

Issued	November	1	2024
	Month	Day	Year
Effective	January	1	2025
	Month	Day	Year

By Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ______________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA
(Name of Issuing Utility)

Replacing Schedule RECA Sheet 6

EVERGY KANSAS CENTRAL RATE AREA
(Territory to which schedule is applicable)

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 6 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

4. The Company shall submit to the State Corporation Commission of Kansas on or before the 20th of the month ending that quarter, a Retail Energy Cost Adjustment report, in a format prescribed by the Commission, showing the calculation of the next quarter's factor.

5. The Company shall submit a calculation of the $ACAF_P$ to the State Corporation Commission of Kansas on or before March 20th of each year in a format prescribed by the Commission, showing the calculation of the ACAF. The Company may elect to file for a change in the ACAF more frequently than once per year.

6. For each twelve-month billing period ending in December, any quarterly differences between actual cost and actual RECA revenue shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs. The Company shall also determine any annualized over or under-recovery relative to the ACAF. The ACAF for an ACA year shall be computed as shown above. Any fuel and purchased power cost over-recovery or under-recovery shall be combined with any over-recovery or under-recovery associated with the previous year's ACAF. The total amount of any over/under recovery shall be divided by the actual sales to Requirements Customers made during the previous ACA year.

7. The ACAF shall be rounded to the nearest $0.000001 per kWh and applied to sales billed on or after the first day of the billing month following the quarter the adjustment has been approved by the Commission or as implemented subject to refund. The ACAF for the current ACA year shall remain in effect until superceded by an ACAF for a subsequent period.

8. Service hereunder is subject to the Company's General Rules and Regulations as approved by the State Corporation Commission of Kansas and any modifications subsequently approved.

9. All provisions of this rate schedule are subject to changes made by order of the regulatory authority having jurisdiction.

10. The WR base line revenue will remain unchanged until a general rate proceeding at which time it will be updated to the current non-fuel revenue reflected in base rates.

	Month	Day	Year
Issued	November	1	2024
Effective	January	1	2025

By ______________
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 7

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

RETAIL ENERGY COST ADJUSTMENT

11. Costs and revenues incurred due to participation in markets associated with RTO's need not be detailed below to be considered F, P or E should the RTO implement a new market settlement charge type not listed below. If the RTO receives approval by FERC to remove or add new charges or credits, Evergy Kansas Central will be permitted to include those new charges or credits in this RECA calculation. Upon notice of such changes, Evergy Kansas Central will notify Staff in writing to the inclusion of the new charges or credits.

The following are Southwest Power Pool ("SPP") market settlement charge types:

Day Ahead Ramp Capability Up Amount
Day Ahead Ramp Capability Down Amount
Day Ahead Ramp Capability Up Distribution Amount
Day Ahead Ramp Capability Down Distribution Amount
Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Ramp Capability Up Amount
Real Time Ramp Capability Down Amount
Real Time Ramp Capability Up Distribution Amount
Real Time Ramp Capability Down Distribution Amount
Real Time Ramp Capability Non-Performance Amount
Real Time Ramp Capability Non-Performance Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount

Issued	November	1	2024
	Month	Day	Year
Effective	January	1	2025
	Month	Day	Year

By

Darrin Ives, Vice President

25-EKCE-205-TAR
Approved
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

ANJ

Index

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 8

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 8 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Demand Reduction Amount
Day Ahead Demand Reduction Distribution Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Day Ahead Combined Interest Resource Adjustment Amount
Real Time Combined Interest Resource Adjustment Amount
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By

Darrin Ives, Vice President

25-EKCE-205-TAR
Approved
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

ANJ

Index ____________________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 9

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable)

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 9 of 10 Sheets

RETAIL ENERGY COST ADJUSTMENT

Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount
Real Time Pseudo Tie Congestion Amount
Real Time Pseudo Tie Losses Amount
Unused Regulation Up Mileage Make Whole Payment Amount
Unused Regulation Down Mileage Make Whole Payment Amount
Revenue Neutrality Uplift Distribution Amount
Real Time Make Whole Payment
Real Time Make Whole Payment Distribution
Integrated Marketplace Facilitation Administration Service
Transmission Congestion Rights Administration Service
Real-Time Uninstructed Resource Deviation Amount
Real-Time Uninstructed Resource Deviation Distribution Amount
Local Reliability Distribution Amount
Day-Ahead Self-Incremental Energy Make Whole Payment Amount
Real-Time Incremental Energy Make Whole Payment Amount,
Reliability Unit Commitment (“RUC”) Self-Incremental Energy Make Whole Payment Amount

12. Virtual Energy Transactions with SPP, (Day-Ahead Virtual Energy, Real-time Virtual Energy, and Day Ahead-Virtual Transaction Fee), shall be included as a cost of Purchased Power as long as the virtual transaction serves a legitimate hedging purpose such as:

- In support of physical operations related to a generating resource, including but not limited to, start-up, shut-down, and unanticipated equipment failures;
- In anticipation of significant deviations in load or weather forecast; or
- Other similar situations in which the primary purpose of entering into the virtual transaction is to reduce risk to Evergy Kansas Central ratepayers.

13. On or before the 20th of each calendar month, the Company shall submit to the State Corporation Commission a report detailing all of the Virtual Energy Transactions entered into the previous calendar month.

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By ____________________
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY KANSAS CENTRAL, INC., & EVERGY KANSAS SOUTH, INC., d.b.a. EVERGY KANSAS CENTRAL SCHEDULE RECA

(Name of Issuing Utility)

Replacing Schedule RECA Sheet 10

EVERGY KANSAS CENTRAL RATE AREA

(Territory to which schedule is applicable) which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

RETAIL ENERGY COST ADJUSTMENT

14. On or before the 20th of each calendar month, the Company shall submit to the State Corporation Commission a report summarizing the activity in Accounts 447, 555, 565, 421, and 426. The report shall provide by Account, by SPP Charge Type for SPP transactions, the net change in the Account balance, and MWh's purchased or sold for the month.

15. Hedging Transactions, as approved by the Commission in Docket No. 23-EKCE-846-TAR, shall be included as a recoverable expense or revenue, recorded to Account 447, Account 501, Account 518, Account 547, Account 555, Account 559.3, or Account 577.3, as long as the transaction serves a legitimate hedging purpose such as:

    - In support of physical operation related to coal, fuel, oil, natural gas, or nuclear;
    - In anticipation of significant deviations in load or weather forecast; or
    - Other situations in which the primary purpose of entering into the physical or financial transaction is to reduce the open price exposure risk to Evergy Kansas Central ratepayers.

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By [signature]
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE ECA

Replacing Schedule ECA Sheet 1

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

ENERGY COST ADJUSTMENT

APPLICABILITY

This Energy Cost Adjustment (ECA) Schedule shall be applicable to all Evergy Kansas Metro's Retail Rate Schedules.

BASIS

Energy costs will be measured and applied to a customer's bill using an ECA factor. The ECA factor is applied on a kilowatt-hour basis ($/kWh). Retail customer charges for energy costs are determined by multiplying the kilowatt-hours of electricity during any calendar month by the corresponding ECA factor for that calendar month.

ENERGY COST ADJUSTMENT

Prior to January 1 of each ECA year, an ECA factor (ECA_P) will be calculated for each calendar month of the ECA year as follows:

$$ECA_P = \frac{(F_P + P_P + E_P + EC_P + T_P - OSSR_P)}{S_P} - \frac{ACA_A}{S_{ACA}}$$

Where:

F_P = Projected cost of nuclear and fossil fuel to be consumed for the generation of electricity during the month in which the ECA is in effect for all Evergy Metro, Inc. customers to be recorded in Account 501, Account 518, Account 547, Account 559.3 and Account 577.3, excluding any Evergy Metro, Inc. internal labor cost.

P_P = Projected cost of purchased power during the month in which the ECA is in effect all Evergy Metro, Inc. customers to be recorded in Account 555, and Evergy Metro, Inc.'s projected charges or credits incurred due to participation in markets associated with Regional Transmission Organizations (RTOs). This includes amounts for all capacity purchases (both exceeding one year and less than one year). This also includes Hedging Transactions as discussed in note 14 to the tariff. This excludes projected amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

Issued	November	1	2024
	Month	Day	Year
Effective	January	1	2025
	Month	Day	Year

By Darrin Ives
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE ECA

Replacing Schedule ECA Sheet 2

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

ENERGY COST ADJUSTMENT

E_P = Projected cost of emission allowances and amortizations during the month in which the ECA is in effect for all Evergy Metro, Inc. customers to be recorded in Account 509.

EC_P = Projected revenues and costs from environmental credits to be recorded in Accounts 411.11 and 411.12 and Accounts 555.2 and 555.3, respectively, during the month in which the ECA is in effect for all Evergy Metro, Inc. customers.

T_P = Projected cost of transmission inside or outside of SPP necessary to make purchases and sales outside of SPP, which is not otherwise recovered through Evergy Kansas Metro Transmission Formula Rate or Transmission Delivery Charge, during the month in which the ECA is in effect for all Evergy Metro, Inc. customers to be recorded in Account 561.4, Account 561.8, Account 565, Account 575.7 and Account 928.

$OSSR_P$ = Projected revenues from off-system sales during the month in which the ECA is in effect, to be recorded in Account 447 and Evergy Metro, Inc.'s projected credits or charges incurred due to participation in markets associated with Regional Transmission Organizations (RTOs). This includes amounts for all capacity sales (both exceeding one year and less than one year). This also includes Hedging Transactions as discussed in note 14 to the tariff. This excludes projected amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

S_P = Projected kWhs to be delivered to all Evergy Metro, Inc. customers during the month in which the ECA is in effect.

S_{ACA} = Projected kWhs for Evergy Kansas Metro customers for the twelve-month period beginning in April of the year following the ECA year.

ACA_A = The Actual Cost Adjustment (ACA) true-up amount for an ECA year, to be calculated by March 1 of the year following the ECA year and to be applied for a twelve-month period beginning April 1 of the year following the ECA year. The true-up amount will reflect any difference between the total ECA revenue for the Retail sales during the ECA year and the actual net costs incurred to achieve those Retail sales. Such true-up amount may be positive or negative. Any remaining balances from prior true-up periods will be added.

	November	1	2024
Issued	Month	Day	Year
	January	1	2025
Effective	Month	Day	Year

By
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE ECA

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

Replacing Schedule ECA Sheet 3

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 3 of 8 Sheets

ENERGY COST ADJUSTMENT

$$ACA_A = ECAREV_A – (F_A + P_A + E_A + EC_A + T_A - OSSRA)) \times \frac{S_{AK}}{S_{AT}}] + ACA_{PRIOR}$$

Where:

$ECAREV_A$ = Actual ECA revenue for Evergy Kansas Metro’s Retail sales during the ECA year.

F_A = Actual total company cost of nuclear and fossil fuel consumed for the generation of electricity for the ECA year recorded in Account 501, Account 518, Account 547, Account 559.3 and Account 577.3, excluding any internal Evergy Metro, Inc. labor costs.

P_A = Actual total company cost of purchased power incurred during the ECA year recorded in Account 555, and Evergy Metro, Inc.’s actual charges or credits incurred due to participation in markets associated with Regional Transmission Organizations (RTOs). This includes amounts for all capacity purchases (both exceeding one year and less than one year). This also includes Hedging Transactions as discussed in note 14 to the tariff. This excludes amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

E_A = Actual total company emission allowance costs and amortizations incurred during the ECA year recorded in Account 509 and gains or losses of emission allowances recorded in Account 411.8 or 411.9 respectively for the previous ACA year.

EC_A = Actual total company revenues and costs from environmental credits recorded in Accounts 411.11 and 411.12 and Accounts 555.2 and 555.3, respectively, during the ECA year.

T_A = Actual total company cost of transmission inside or outside of SPP necessary to make purchases and sales outside of SPP, which is not otherwise recovered through the Evergy Kansas Metro Transmission Formula Rate or Transmission Delivery Charge, and recorded to Account 561.4, Account 561.8, Account 565, Account 575.7 and Account 928.

$OSSR_A$ = Actual total company revenues from off-system sales during the month in which the ECA is in effect, recorded in Account 447 and Evergy Metro, Inc.’s amounts incurred due to participation in markets associated with Regional Transmission Organizations (RTOs). This includes amounts for all capacity sales (both exceeding one year and less than one year). This also includes Hedging Transactions as discussed in note 14 to the tariff.

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By
Darrin Ives, Vice President

25-EKCE-205-TAR ANJ
Approved
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE ECA

Replacing Schedule ECA Sheet 4

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

ENERGY COST ADJUSTMENT

S_{AK} = Actual kWhs delivered to Evergy Kansas Metro customers during the ECA year.

S_{AT} = Actual kWhs delivered to all Evergy Metro, Inc. customers during the ECA year.

ACA_{PRIOR} = Remaining true-up amounts from previous ECA years (positive or negative).

NOTES TO THE TARIFF:

1. On or before December 20th prior to each ECA year, Evergy Kansas Metro will submit a report containing the projected monthly ECA factors on a $/kWh basis for each month of the coming ECA year. Such report will set the monthly ECA factors for January, February and March of the ECA year. Evergy Kansas Metro will publish such projected monthly ECA factors, and any updates to such monthly ECA factors to consumers.

2. On or before the 20th day of March, June, and September of each ECA year, Evergy Kansas Metro will submit a report containing updated projected ECA factors for the remaining months of the effective ECA year. Such updated projected ECA factors will set the monthly ECA factors for the next calendar quarter of the ECA year. Such report shall also compare the original ECA revenue projections and the then-current ECA year-end projections on a total revenue basis. If the original projection and the then-current projection become significantly out of balance at any time during the ECA year, the remaining monthly ECA factors may be adjusted to address the anticipated difference.

3. On or before the 1st day of March each year beginning March 1, 2009, Evergy Kansas Metro will file an application that provides the true-up reconciliation for the preceding ECA year, otherwise known as the Actual Cost Adjustment (“ACA”). Such reconciliation amount, if any, for a given ECA year will be applied as an adjustment to the monthly ECA factors for the 12-month period beginning April following the reconciled ECA year. The Commission may make such ACA subject to correction in whole or in part, pending final determination on the application. All revenues collected pursuant to the ECA tariff shall be deemed to be revenues subject to adjustment until the ACA review is complete, the Commission has issued a final order in the ACA matter, and all terms and conditions of such order are satisfied. The Commission shall make a final determination on the adjustment, including the reasonableness and prudence of the actual ECA costs incurred during the ECA year, within two hundred forty (240) days of the filing of the application. Prudent operation of Evergy Metro, Inc.’s system will be consistent with industry standards regarding economic dispatch, reliability, maintenance and fuel procurement as such is necessary to minimize the impact of this ECA tariff on customer rates.

	Month	Day	Year
Issued	November	1	2024
Effective	January	1	2025

By ____________
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

ANJ

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE ECA

Replacing Schedule ECA Sheet 5

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 5 of 8 Sheets

ENERGY COST ADJUSTMENT

4. The monthly ECA factor will be expressed in dollars per kilowatt-hour rounded to five decimal places.

5. Each ECA year will be a calendar year, with the first year beginning January 1, 2008.

6. The ECA amount on each customer bill will be calculated such that the ECA factor for each calendar month within the billing period is applied to the estimated usage for the appropriate calendar month (i.e., prorated) based on the number of days of usage in each calendar month.

7. The references to Accounts within the ECA tariff are as defined in the FERC uniform system of accounts. Evergy Kansas Metro customers include Retail customers that receive service under one of the Evergy Kansas Metro Retail tariffs and wholesale Full Requirement Service Sales for Resale customers that receive firm service for the full capacity and energy needs on a contract basis of one year or longer from Evergy Kansas Metro.

8. Evergy Metro, Inc. customers include Retail customers that receive service under one of the Evergy Kansas Metro or Evergy Missouri Metro Retail tariffs and wholesale Full Requirement Service Sales for Resale customers that receive firm service for the full capacity and energy needs on a contract basis of one year or longer from Evergy Kansas Metro or Evergy Missouri Metro.

9. This tariff is subject to Evergy Kansas Metro's Rules and Regulations as approved by the State Corporation Commission of Kansas.

10. This tariff is subject to all applicable Kansas statutes and regulations regarding the filing and investigation of complaints on unreasonable, unfair or unjust rates.

11. On or before the 20th of each calendar month, the Company shall submit to the State Corporation Commission a report detailing all of the Virtual Energy Transactions entered into the previous calendar month.

12. On or before the 20th of each calendar month, the Company shall submit to the State Corporation Commission a report summarizing the activity in Accounts 447, 555 and 565. The Report shall provide by Account, by SPP Charge Type for SPP transactions, the net change in the Account balance, and MWhs purchased or sold for the month.

	Month	Day	Year
Issued	November	1	2024
Effective	January	1	2025

By ____________
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE ECA

Replacing Schedule ECA Sheet 6

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

ENERGY COST ADJUSTMENT

13. Costs and revenues incurred due to participation in markets associated with RTO's need not be detailed below to be considered F, P, E or OSSR should the RTO implement a new market settlement charge type not listed below. If the RTO receives approval by FERC to remove or add new charges or credits, Evergy Metro will be permitted to include those new charges or credits in this ECA calculation. Upon notice of such changes, Evergy Metro will notify Staff in writing to the inclusion of the new charges or credits.

The following are Southwest Power Pool ("SPP") market settlement charge types:

Day Ahead Ramp Capability Up Amount
Day Ahead Ramp Capability Down Amount
Day Ahead Ramp Capability Up Distribution Amount
Day Ahead Ramp Capability Down Distribution Amount
Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Ramp Capability Up Amount
Real Time Ramp Capability Down Amount
Real Time Ramp Capability Up Distribution Amount
Real Time Ramp Capability Down Distribution Amount
Real Time Ramp Capability Non-Performance Amount
Real Time Ramp Capability Non-Performance Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By [signature]
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE ECA

Replacing Schedule ECA Sheet 7

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 7 of 8 Sheets

ENERGY COST ADJUSTMENT

Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Demand Reduction Amount
Day Ahead Demand Reduction Distribution Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Day Ahead Combined Interest Resource Adjustment Amount
Real Time Combined Interest Resource Adjustment Amount
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved ANJ
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE ECA

Replacing Schedule ECA Sheet 8

which was filed December 28, 2023

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 8 of 8 Sheets

ENERGY COST ADJUSTMENT

Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount
Real Time Pseudo Tie Congestion Amount
Real Time Pseudo Tie Losses Amount
Unused Regulation Up Mileage Make Whole Payment Amount
Unused Regulation Down Mileage Make Whole Payment Amount
Revenue Neutrality Uplift Distribution Amount
Real Time Make Whole Payment
Real Time Make Whole Payment Distribution
Integrated Marketplace Facilitation Administration Service
Transmission Congestion Rights Administration Service
Real-Time Uninstructed Resource Deviation Amount
Real-Time Uninstructed Resource Deviation Distribution Amount
Local Reliability Distribution Amount
Day-Ahead Self-Incremental Energy Make Whole Payment Amount
Real-Time Incremental Energy Make Whole Payment Amount,
Reliability Unit Commitment (“RUC”) Self-Incremental Energy Make Whole Payment Amount

14. Hedging Transactions, as approved by the Commission in Docket No. 23-EKCE-846-TAR, shall be included as a recoverable expense or revenue, recorded to Account 447, Account 501, Account 518, Account 547, Account 555, Account 559.3 or Account 577.3, as long as the transaction serves a legitimate hedging purpose such as:

    - In support of physical operation related to coal, fuel, oil, natural gas, or nuclear;
    - In anticipation of significant deviations in load or weather forecast; or
    - Other situations in which the primary purpose of entering into the physical or financial transaction is to reduce the open price exposure risk to Evergy Kansas Metro ratepayers.

Issued November 1 2024
Month Day Year

Effective January 1 2025
Month Day Year

By
Darrin Ives, Vice President

25-EKCE-205-TAR
Approved
Kansas Corporation Commission
December 31, 2024
/s/ Lynn Retz

ANJ

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.11
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.11

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS: An accumulation period is the six 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"). The two six-month accumulation periods each year through May 27, 2021, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format with formulas intact to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
January – June	By August 1	October – September
July – December	By February 1	April – March

A recovery period consists of the months during which the FAR is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES: Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off system sales – all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

January 9, 2023

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.12
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.12

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR - R)

FC = Fuel Costs Incurred to Support Sales:
The following costs reflected in FERC Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance and leases, applicable taxes, natural gas costs, fuel quality adjustments, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), oil costs for commodity, transportation, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, powder activated carbon, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400: residual costs and revenues associated with combustion product, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

The following costs reflected in FERC Account Number 518:
Subaccount 518000: nuclear fuel commodity and hedging costs;
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:
Subaccount 547000: natural gas and oil costs for commodity, transportation, storage, taxes, fees and fuel losses, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers);
Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;
Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off system sales;
Subaccount 547300: fuel additives.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:
Subaccount 509000: NOx and SO_2 emission allowance costs and revenue amortizations offset by revenues from the sale of NOx and SO_2 emission allowances, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers).

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:
Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), charges and credits related to the SPP Integrated Marketplace ("IM") or other IMs including, energy, revenue neutrality, make whole and out of merit payments and distributions, over collected losses payments and distributions, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("ARR") settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, load/export charges, ancillary services including non-performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including uplift charges or credits;
Subaccount 555005: capacity charges for capacity purchases one year or less in duration;
Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off system sales.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.14
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.14

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:
Subaccount 565000: non-SPP transmission used to serve off system sales or to make purchases for load and 20.91% of the SPP transmission service costs which includes the schedules listed below as well as any adjustment to the charges in the schedules below:
- Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
- Schedule 8 – Non Firm Point to Point Transmission Service
- Schedule 9 – Network Integration Transmission Service
- Schedule 10 – Wholesale Distribution Service
- Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;
Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;
Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits. Off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year shall be excluded from OSSR component;
Subaccount 447012: capacity charges for capacity sales one year or less in duration;
Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standards.

Any cost identified above which is a Missouri-only cost shall be grossed up by the current kWh energy factor, included in the ANEC calculation and allocated as indicated in component J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.15
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.15

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party's right to challenge the inclusion as outlined in E. below;

B. The Company will make a filing with the Commission giving the Commission notice of the new schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new schedule, charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new schedule, charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues;

E. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new schedule or charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.16
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.16

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

F. A party other than the Company may seek the inclusion of a new schedule or charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing date of August 1 or February 1. Such a filing shall give the Commission notice that such party believes the new schedule or charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

SPP IM charge/revenue types that are included in the FAC are listed below:

- Day Ahead Regulation Down Service Amount
- Day Ahead Regulation Down Service Distribution Amount
- Day Ahead Regulation Up Service Amount
- Day Ahead Regulation Up Service Distribution Amount
- Day Ahead Spinning Reserve Amount
- Day Ahead Spinning Reserve Distribution Amount
- Day Ahead Supplemental Reserve Amount
- Day Ahead Supplemental Reserve Distribution Amount
- Real Time Contingency Reserve Deployment Failure Amount
- Real Time Contingency Reserve Deployment Failure Distribution Amount
- Real Time Regulation Service Deployment Adjustment Amount
- Real Time Regulation Down Service Amount
- Real Time Regulation Down Service Distribution Amount
- Real Time Regulation Non-Performance
- Real Time Regulation Non-Performance Distribution
- Real Time Regulation Up Service Amount
- Real Time Regulation Up Service Distribution Amount
- Real Time Spinning Reserve Amount

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.17
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.17

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Virtual Energy Transaction Fee Amount
Day Ahead Demand Reduction Amount
Day Ahead Demand Reduction Distribution Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.18
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.18

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)
- Real Time Pseudo Tie Congestion Amount
- Real Time Pseudo Tie Losses Amount
- Unused Regulation Up Mileage Make Whole Payment Amount
- Unused Regulation Down Mileage Make Whole Payment Amount
- Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. 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 the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (“BF”)

S_{AP} = Net system input (“NSI”) in kWh for the accumulation period

BF = Company base factor costs per kWh: $0.01542

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)
MO Losses = 6.32%; KS Losses = 7.52%; Sales for Resale, Municipals Losses = 6.84%

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest 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 in this tariff.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	Third	Revised Sheet No. 50.19
Canceling P.S.C. MO. No.	7	Second	Revised Sheet No. 50.19

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through December 5, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

FAR = FPA/S_{RP}

Single Accumulation Period Transmission/Substation Voltage $FAR_{Trans/Sub}$ = FAR * $VAF_{Trans/Sub}$
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}
Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}

Annual Primary Voltage $FAR_{Trans/Sub}$ = Aggregation of the two Single Accumulation Period Transmission/Substation Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered
Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period Missouri retail NSI in kWh, at the generation level

VAF = Expansion factor by voltage level
$VAF_{Trans/Sub}$ = Expansion factor for transmission/substation and higher voltage level customers
VAF_{Prim} = Expansion factor for between primary and trans/sub voltage level customers
VAF_{Sec} = Expansion factor for lower than primary voltage customers

TRUE-UPS

After completion of each RP, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "I" above.

The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider 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 FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

KANSAS CITY POWER AND LIGHT COMPANY

P.S.C. MO. No. 7 4th Revised Sheet No. 50.20

Canceling P.S.C. MO. No. 7 3rd Revised Sheet No. 50.20

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided June 8, 2017 through Effective Date of Rates in Case No. ER-2018-0145)
Effective for Customer Usage Beginning October 1, 2018 through March 31, 2019

Accumulation Period Ending:			June 30, 2018
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$166,937,457
2	Net Base Energy Cost (B)	-	$124,074,917
	2.1 Base Factor (BF)		$0.01542
	2.2 Accumulation Period NSI (S_{AP})		8,046,363,000
3	(ANEC-B)		$42,862,540
4	Jurisdictional Factor (J)	x	56.625354%
5	(ANEC-B)*J		$24,271,065
6	Customer Responsibility	x	95%
7	95% *((ANEC-B)*J)		$23,057,512
8	True-Up Amount (T)	+	$1,965,134
9	Interest (I)	+	$704,419
10	Prudence Adjustment Amount (P)	+	$0
11	Fuel and Purchased Power Adjustment (FPA)	=	$25,727,065
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	8,986,742,303
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00286
14			
15	Current Period $FAR_{Trans/Sub}$ = FAR x $VAF_{Trans/Sub}$		$0.00292
16	Prior Period $FAR_{Trans/Sub}$	+	$0.00238
17	Current Annual $FAR_{Trans/Sub}$	=	$0.00530
18			
19	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00299
20	Prior Period FAR_{Prim}	+	$0.00244
21	Current Annual FAR_{Prim}	=	$0.00543
22			
23	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00306
24	Prior Period FAR_{Sec}	+	$0.00249
25	Current Annual FAR_{Sec}	=	$0.00555
26			
27	$VAF_{Trans/Sub}$ = 1.0195		
28	VAF_{Prim} = 1.0451		
29	VAF_{Sec} = 1.0707		

Issued: July 31, 2018 Effective: October 1, 2018
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.21
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.21

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS: An accumulation period is the six 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"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format with formulas intact to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
January – June	By August 1	October – September
July – December	By February 1	April – March

A recovery period consists of the months during which the FAR is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES: Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off system sales – all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.22
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.22

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR - R)

FC = Fuel Costs Incurred to Support Sales:
The following costs reflected in FERC Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, applicable taxes, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, taxes and depreciation, natural gas costs, fuel quality adjustments, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), oil costs for commodity, transportation, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.

Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems (“AQCS”) operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustments, powder activated carbon, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400: residuals costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

The following costs reflected in FERC Account Number 518:
Subaccount 518000: nuclear fuel commodity and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 518 Accounts
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.23
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.23

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:
Subaccount 547000: natural gas and oil costs for commodity, transportation, storage, taxes, fees and fuel losses, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers);
Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;
Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off system sales;
Subaccount 547300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia or other consumables which perform similar functions.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:
Subaccount 509000: NOx and SO_2 emission allowance costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) offset by revenue amortizations and revenues from the sale of NOx and SO_2 emission allowances.

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:
Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), charges and credits related to the SPP Integrated Marketplace ("IM") or other IMs, including energy, revenue neutrality, make whole and out of merit payments and distributions, over collected losses payments and distributions, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("ARR") settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, load/export charges, ancillary services including non-performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including uplift charges or credits, excluding (1) the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff and (2) the Missouri allocated portion of the difference between the amount of the bilateral contract for hydro energy purchased from CNPPID and the average monthly LMP value at the CNPPID nodes times the amount of energy sold to the SPP at the CNPPID nodes. The CNPPID nodes are defined as NPPD.KCPL.JFY1, NPPD.KCPL.JFY2, NPPD.KCPL.JHN1, NPPD.KCPL.JN11, NPPD.KCPL.JN12;

Subaccount 555005: capacity charges for capacity purchases one year or less in duration;
Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off system sales.

January 9, 2023

Issued: December 2, 2022 — Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President — 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

	P.S.C. MO. No.	7	First	Revised Sheet No. 50.24
Canceling	P.S.C. MO. No.	7		Original Sheet No. 50.24

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:
Subaccount 565000: non-SPP transmission used to serve off system sales or to make purchases for load and 26.40% of the SPP transmission service costs which includes the schedules listed below as well as any adjustment to the charges in the schedules below:

- Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
- Schedule 8 – Non Firm Point to Point Transmission Service
- Schedule 9 – Network Integration Transmission Service
- Schedule 10 – Wholesale Distribution Service
- Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.
Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;
Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;
Subaccount 565030: the allocation of the allowed costs in the 565000 account attributed to off system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, but excluding (1) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year and (2) the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff. Additional revenue will be added at an imputed 75% of the unsubscribed portion associated with the Solar Subscription Rider valued at market price;
Subaccount 447012: capacity charges for capacity sales one year or less in duration;
Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standards.

Any cost identified above which is a Missouri-only cost shall be grossed up by the current kWh energy factor, included in the ANEC calculation and allocated as indicated in component J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.25
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.25

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party's right to challenge the inclusion as outlined in E. below;

B. The Company will make a filing with the Commission giving the Commission notice of the new schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new schedule, charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new schedule, charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues;

E. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new schedule or charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

January 9, 2023

Issued: December 2, 2022 | Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President | 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.26
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.26

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

F. A party other than the Company may seek the inclusion of a new schedule or charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing date of August 1 or February 1. Such a filing shall give the Commission notice that such party believes the new schedule or charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion
of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

SPP IM charge/revenue types that are included in the FAC are listed below:

- Day Ahead Regulation Down Service Amount
- Day Ahead Regulation Down Service Distribution Amount
- Day Ahead Regulation Up Service Amount
- Day Ahead Regulation Up Service Distribution Amount
- Day Ahead Spinning Reserve Amount
- Day Ahead Spinning Reserve Distribution Amount
- Day Ahead Supplemental Reserve Amount
- Day Ahead Supplemental Reserve Distribution Amount
- Real Time Contingency Reserve Deployment Failure Amount
- Real Time Contingency Reserve Deployment Failure Distribution Amount
- Real Time Regulation Service Deployment Adjustment Amount
- Real Time Regulation Down Service Amount
- Real Time Regulation Down Service Distribution Amount
- Real Time Regulation Non-Performance
- Real Time Regulation Non-Performance Distribution
- Real Time Regulation Up Service Amount
- Real Time Regulation Up Service Distribution Amount
- Real Time Spinning Reserve Amount

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No.	50.27
Canceling P.S.C. MO. No.	7		Original Sheet No.	50.27

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Virtual Energy Transaction Fee Amount
Day Ahead Demand Reduction Amount
Day Ahead Demand Reduction Distribution Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.28
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.28

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)
- Real Time Pseudo Tie Congestion Amount
- Real Time Pseudo Tie Losses Amount
- Unused Regulation Up Mileage Make Whole Payment Amount
- Unused Regulation Down Mileage Make Whole Payment Amount
- Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. 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 the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (“BF”)

S_{AP} = Net system input (“NSI”) in kWh for the accumulation period

BF = Company base factor costs per kWh: $0.01675

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)
MO Losses = 6.32%; KS Losses = 7.52%; Sales for Resale, Municipals Losses = 6.84%

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest 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 in this tariff.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.29
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.29

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

FAR = FPA/S_{RP}

Single Accumulation Period Transmission Voltage FAR_{Trans} = FAR * VAF_{Trans}
Single Accumulation Period Substation Voltage FAR_{Sub} = FAR * VAF_{Sub}
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}
Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}

Annual Primary Voltage FAR_{Trans} = Aggregation of the two Single Accumulation Period Transmission Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Sub} = Aggregation of the two Single Accumulation Period Substation Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered
Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period Missouri retail NSI in kWh, at the generation level

VAF = Expansion factor by voltage level
VAF_{Trans} = Expansion factor for transmission voltage level customers
VAF_{Sub} = Expansion factor for substation to transmission voltage level customers
VAF_{Prim} = Expansion factor for between primary and substation voltage level customers
VAF_{Sec} = Expansion factor for lower than primary voltage customers

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	First	Revised Sheet No. 50.30
Canceling P.S.C. MO. No.	7		Original Sheet No. 50.30

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 through the Day Prior to the Effective Date of this Tariff Sheet)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

TRUE-UPS

After completion of each RP, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component “T” above. Interest on the true-up adjustment will be included in component “I” above.

The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider 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 FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in component “P” above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component “I” above.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	9th	Revised Sheet No.	50.31
Canceling P.S.C. MO. No.	7	8th	Revised Sheet No.	50.31

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided December 6, 2018 and through the Day Prior to the Effective Date of Rates in Case No. ER-2022-0129)
Effective for Customer Usage Beginning April 2023 through September 2023

Accumulation Period Ending: **December 2022**			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$156,985,768
2	Net Base Energy Cost (B)	-	$140,118,423
	2.1 Base Factor (BF)		$0.01675
	2.2 Accumulation Period NSI (S_{AP})		8,365,278,998
3	(ANEC-B)		$16,867,345
4	Jurisdictional Factor (J)	x	57.833636%
5	(ANEC-B)*J		$9,754,999
6	Customer Responsibility	x	95%
7	95% *((ANEC-B)*J)		$9,267,249
8	True-Up Amount (T)	+	($278,946)
9	Interest (I)	+	($404,809)
10	Prudence Adjustment Amount (P)	+	($703,825)
11	Fuel and Purchased Power Adjustment (FPA)	=	$7,879,669
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	8,848,005,035
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00089
14			
15	Current Period FAR_{Trans} = FAR x VAF_{Trans}		$0.00090
16	Prior Period FAR_{Trans}	+	$0.00002
17	Current Annual FAR_{Trans}	=	$0.00092
18			
19	Current Period FAR_{Sub} = FAR x VAF_{Sub}		$0.00090
20	Prior Period FAR_{Sub}	+	$0.00002
21	Current Annual FAR_{Sub}	=	$0.00092
22			
23	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00092
24	Prior Period FAR_{Prim}	+	$0.00002
25	Current Annual FAR_{Prim}	=	$0.00094
26			
27	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00094
28	Prior Period FAR_{Sec}	+	$0.00002
29	Current Annual FAR_{Sec}	=	$0.00096
30	VAF_{Trans} = 1.0129		
31	VAF_{Sub} = 1.0162		
32	VAF_{Prim} = 1.0383		
33	VAF_{Sec} = 1.0592		

Issued: January 31, 2023 Effective: April 1, 2023
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 Original Sheet No. 50.32

Canceling P.S.C. MO. No. Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS: An accumulation period is the six 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"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format with formulas intact to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
January – June	By August 1	October – September
July – December	By February 1	April – March

A recovery period consists of the months during which the FAR is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES: Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated jurisdictional costs for the fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales – all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) in April and October subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7		Original Sheet No. 50.33
Canceling P.S.C. MO. No.			Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR R)

FC = Fuel costs, excluding decommissioning and retirement costs, incurred to support sales and revenues associated with the Company's in-service generating plants:

The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:

Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, applicable taxes, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, taxes and depreciation, natural gas costs including reservation charges, fuel quality adjustments, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), oil costs for commodity, transportation, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.

Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to native load;

Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to off system sales;

Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustments, powder activated carbon, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;

Subaccount 501400 and 501420: residuals costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

The following costs reflected in FERC Account Number 518:

Subaccount 518000: nuclear fuel commodity and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 518 Accounts

Subaccount 518201: nuclear fuel waste disposal expense;

Subaccount 518100: nuclear fuel oil.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:

Subaccount 547000: natural gas and oil costs for commodity, transportation, storage, taxes, fees and fuel losses~~,~~ and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers)

Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;

Subaccount 547027: natural gas reservation charges;

Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off system sales;

Subaccount 547300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia or other consumables which perform similar functions.

E = Net Emission Costs:

The following costs and revenues reflected in FERC Account Number 509:
Subaccount 509000: NOx and SO_2 emission allowance costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) offset by revenue amortizations.

PP = Purchased Power Costs:

The following costs or revenues reflected in FERC Account Number 555:
Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), charges and credits related to the SPP Integrated Marketplace ("IM") or other IMs, including energy, revenue neutrality, make whole and out of merit payments and distributions, over collected losses payments and distributions, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("ARR") settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, load/export charges, ancillary services including non-performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including uplift charges or credits, excluding (1) the amounts associated with purchased power agreements ("PPA") associated with the Renewable Energy Rider tariff, (2) costs associated with the CNPPID Hydro PPA, and (3) net costs associated with wind PPA entered into after May 2019 whose costs exceed their revenues resulting in a net loss;

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 Original Sheet No. 50.35

Canceling P.S.C. MO. No. Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

PP = Purchased Power Costs (continued):

Subaccount 555005: capacity charges for capacity purchases one year or less in duration;

Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off system sales.

For solar subscription projects, factor PP shall not include costs for any undersubscribed portion of the Solar Subscription Program resources(s) allocated to shareholders under Tariff Sheet No. 39E.

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:
Subaccount 565000: non-SPP transmission used to serve off system sales or to make purchases for load and 28.50% of the SPP transmission service costs which includes the schedules listed below as well as any adjustment to the charges in the schedules below:

- Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
- Schedule 8 – Non Firm Point to Point Transmission Service
- Schedule 9 – Network Integration Transmission Service
- Schedule 10 – Wholesale Distribution Service
- Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;

Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;

Subaccount 565030: the allocation of the allowed costs in the 565000 account attributed to off system sales.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	1st	Revised Sheet No. 50.36
Canceling P.S.C. MO. No.			Original Sheet No. 50.36

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, but excluding (1) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year, (2) the amounts associated with PPA associated with the Renewable Energy Rider tariff, (3) SPP revenues associated with the CNPPID Hydro PPA and (4) net costs associated with wind PPA entered into after May 2019 whose costs exceed their revenues resulting in a net loss.

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 Solar Subscription Rider resource allocated to shareholders under the approved stipulation in File No. ER-2022-0129.

Subaccount 447012: capacity charges for capacity sales one year or less in duration;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Emissions and Environmental Credits (this will only include Renewable Energy Credits) Gains or losses:

Subaccounts 411.8 and 411.9: gains and losses of the sale of emission allowances in the current FAC accumulation period.

Subaccounts 411.11 and 411.12: for gains and losses on the sale of environmental credits (this will only include Renewable Energy Credits) in the current FAC accumulation period.

Any cost identified above which is a Missouri-only cost shall be grossed up by the current kWh energy factor, included in the ANEC calculation and allocated as indicated in component J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 Original Sheet No. 50.37

Canceling P.S.C. MO. No. Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC.

SPP IM charge/revenue types that are included in the FAC are listed below:
- Day-Ahead Ramp Capability Up Amount
- Day-Ahead Ramp Capability Down Amount
- Day-Ahead Ramp Capability Up Distribution Amount
- Day-Ahead Ramp Capability Down Distribution Amount
- Day Ahead Regulation Down Service Amount
- Day Ahead Regulation Down Service Distribution Amount
- Day Ahead Regulation Up Service Amount
- Day Ahead Regulation Up Service Distribution Amount
- Day Ahead Spinning Reserve Amount
- Day Ahead Spinning Reserve Distribution Amount
- Day Ahead Supplemental Reserve Amount
- Day Ahead Supplemental Reserve Distribution Amount
- Real Time Contingency Reserve Deployment Failure Amount
- Real Time Contingency Reserve Deployment Failure Distribution Amount
- Real Time Ramp Capability Up Amount
- Real Time Ramp Capability Down Amount
- Real Time Ramp Capability Up Distribution Amount
- Real Time Ramp Capability Down Distribution Amount
- Real Time Ramp Capability Non-Performance Amount
- Real Time Ramp Capability Non-Performance Distribution Amount
- Real Time Regulation Service Deployment Adjustment Amount
- Real Time Regulation Down Service Amount
- Real Time Regulation Down Service Distribution Amount
- Real Time Regulation Non-Performance
- Real Time Regulation Non-Performance Distribution
- Real Time Regulation Up Service Amount
- Real Time Regulation Up Service Distribution Amount
- Real Time Spinning Reserve Amount
- Real Time Spinning Reserve Distribution Amount
- Real Time Supplemental Reserve Amount
- Real Time Supplemental Reserve Distribution Amount
- Day Ahead Asset Energy
- Day Ahead Non-Asset Energy
- Day Ahead Virtual Energy Amount

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 Original Sheet No. 50.38

Canceling P.S.C. MO. No. Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Demand Reduction Amount
Day Ahead Demand Reduction Distribution Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount
Day Ahead Combined Interest Resource Adjustment Amount
Real Time Combined Interest Resource Adjustment Amount
Real Time Pseudo Tie Congestion Amount
Real Time Pseudo Tie Losses Amount
Unused Regulation Up Mileage Make Whole Payment Amount
Unused Regulation Down Mileage Make Whole Payment Amount
Revenue Neutrality Uplift Distribution Amount

FILED - Missouri Public Service Commission - 01/09/2023 - ER-2022-0129 - YE-2023-0104

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 Original Sheet No. 50.39

Canceling P.S.C. MO. No. Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. 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 the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor ("BF")

S_{AP} = Net system input ("NSI") in kWh for the accumulation period

BF = Company base factor costs per kWh: $0.01829

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)
MO Losses = 6.09%; KS Losses = 6.51%; Sales for Resale, Municipals Losses = 6.84%

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest 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 in this tariff.

January 9, 2023

Issued: December 2, 2022 Effective: ~~January 1, 2023~~
Issued by: Darrin R. Ives, Vice President 1200 Main, Kansas City, MO 64105

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No. 7 Original Sheet No. 50.40

Canceling P.S.C. MO. No. Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

FAR = FPA/S_{RP}

Single Accumulation Period Transmission Voltage FAR_{Trans} = FAR * VAF_{Trans}
Single Accumulation Period Substation Voltage FAR_{Sub} = FAR * VAF_{Sub}
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}
Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}

Annual Primary Voltage FAR_{Trans} = Aggregation of the two Single Accumulation Period Transmission Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Sub} = Aggregation of the two Single Accumulation Period Substation Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered
Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period Missouri retail NSI in kWh, at the generation level

VAF = Expansion factor by voltage level
- VAF_{Trans} = Expansion factor for transmission voltage level customers
- VAF_{Sub} = Expansion factor for substation to transmission voltage level customers
- VAF_{Prim} = Expansion factor for between primary and substation voltage level customers
- VAF_{Sec} = Expansion factor for lower than primary voltage customers

TRUE-UPS

After completion of each RP, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "I" above.

The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7		Original Sheet No. 50.41
Canceling P.S.C. MO. No.			Sheet No.

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider 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 FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

P.S.C. MO. No.	7	4th	Revised Sheet No. 50.42
Canceling P.S.C. MO. No.	7	3rd	Revised Sheet No. 50.42

For Missouri Retail Service Area

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 9, 2023 and Thereafter)
Effective for the Customer Usage Beginning April 2025 through September 2025

Accumulation Period Ending: **December 2024**			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$153,568,261
2	Net Base Energy Cost (B)	-	$148,006,228
	2.1 Base Factor (BF)		$0.01829
	2.2 Accumulation Period NSI (S_{AP})		8,092,194,001
3	(ANEC-B)		$5,562,033
4	Jurisdictional Factor (J)	x	55.1231%
5	(ANEC-B)*J		$3,065,965
6	Customer Responsibility	x	95%
7	95% *((ANEC-B)*J)		$2,912,666
8	True-Up Amount (T)	+	($872,202)
9	Interest (I)	+	$288,915
10	Prudence Adjustment Amount (P)	+	$0
11	Fuel and Purchased Power Adjustment (FPA)	=	$2,329,380
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	8,893,846,174
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00026
14			
15	Current Period FAR_{Trans} = FAR x VAF_{Trans}		$0.00027
16	Prior Period FAR_{Trans}	+	$0.00100
17	Current Annual FAR_{Trans}	=	$0.00127
18			
19	Current Period FAR_{Sub} = FAR x VAF_{Sub}		$0.00027
20	Prior Period FAR_{Sub}	+	$0.00101
21	Current Annual FAR_{Sub}	=	$0.00128
22			
23	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00027
24	Prior Period FAR_{Prim}	+	$0.00102
25	Current Annual FAR_{Prim}	=	$0.00129
26			
27	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00028
28	Prior Period FAR_{Sec}	+	$0.00104
29	Current Annual FAR_{Sec}	=	$0.00132
30	VAF_{Trans} = 1.0300		
31	VAF_{Sub} = 1.0378		
32	VAF_{Prim} = 1.0497		
33	VAF_{Sec} = 1.0690		

MidAmerican ENERGY

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 2
Filed with the Iowa Utilities Board

Substitute Original Sheet No. 431
Canceling Original Sheet No. 431

CLAUSE EAC – ENERGY ADJUSTMENT

APPLICATION

To all price schedules for electric service. The Energy Adjustment clause (EAC) will be applied monthly to all kilowatt-hour sales, under all rates, riders, and individual contracts on file with the Iowa Utilities Board where the charge for such energy is subject to adjustment for increases and decreases in the cost of fuel. The cost recovery factor is applied on a monthly basis as a separately billed charge to all kilowatt-hours, for the purpose of billing. The cost recovery factor shall be determined annually per the T
formula below and shall be filed with the Iowa Utilities Board no later than five business days before the first billing cycle begins each March. All provisions of the customer's T
current applicable rate schedule will apply in addition to this charge.

ENERGY ADJUSTMENT CLAUSE FACTOR:

Annually, the estimated Iowa jurisdictional cost of energy, plus the prior year's cumulative excess or deficiency which arises out of the difference between the actual costs and actual recoveries, will be divided by the estimated annual jurisdictional electric energy consumed under rates set by the Iowa Utilities Board to calculate the annual energy adjustment clause factor. The resulting factor E will be filed with the Iowa Utilities Board no later than five days before the first March billing cycle. N | | | | | N

Monthly, the charges for all kilowatt-hours of energy supplied to designated customers shall be increased or decreased by the annual energy adjustment charge or credit to the nearest $0.00001 determined as follows: T

Where:

$$E = \frac{EC + A}{EJ} - B$$ T T

D

Where the letter E precedes the letters C and J, the quantity is estimated.

Issued: August 6, 2014
Issued by Naomi G. Czachura
Vice President

Effective: July 31, 2014

CLAUSE EAC – ENERGY ADJUSTMENT (continued)

The cost of contract, emergency and economy energy purchased in account 555. Purchases of capacity and energy from qualifying alternate energy production facilities shall be included.

The cost of energy produced for non-jurisdictional sales, including sales for resale, is not includable in the energy adjustment clause.

The cost of energy will be adjusted by revenues from the sale of renewable energy credits, carbon dioxide credits or other environmentally related benefits associated with MidAmerican Energy's renewable power projects and private generation outflow purchases under Rate IO as entered into accounts 456, 411.8 and 411.9.

The cost of energy will be adjusted by the pre-tax amount of any federal production
tax credits associated with renewable power projects as entered into account 409.1, ~~T~~
grossed up at the Gross Revenue Conversion Factor ("GRCF"), calculated as 1/[(1- ~~N~~
SIT) x (1-FIT)], where SIT is equal to the effective Iowa State Income Tax Rate in ~~N~~
effect during the Tax Period and FIT is equal to the Federal Income Tax Rate in ~~N~~
effect during the Tax Period, reduced for any negative energy settlements from ~~N/T~~
those renewable power projects that result during the period the projects are eligible
for the production tax credit, as recorded in account 447.043. However, this
adjustment will not include twenty-five percent (25%) of the federal production tax T
credits associated with Quad Cities Nuclear Generating Station Units 1 and 2 and T
100% of the federal production tax credits associated with the 706 GE SLE and S- T
type 1.5 MW turbines, ~~or~~ the 510 Siemens turbines, or the fifty (50) Mitsubishi T
turbines listed below in the event the turbines are repowered and the repowered
assets are not included in rate base for determining base rates.

Turbines Subject to Potential Repowering

Ratemaking Principle Docket	Name of Wind Farm	MW	Number of Turbines	Model
Wind I	Intrepid	160.5	107	GE 1.5s
Wind I	Century	150	100	GE 1.5s
Wind III	Victory	99	66	GE 1.5sle
Wind III	Pomeroy	123	82	GE 1.5sle
Wind IV	Pomeroy	126	84	GE 1.5sle
Wind IV	Century	15	10	GE 1.5sle
Wind IV	Charles City	75	50	GE 1.5sle
Wind IV	Carroll	150	100	GE 1.5sle
Wind V	Walnut	100.5	67	GE 1.5sle
Wind V	Pomeroy	7.5	5	GE 1.5sle

MIDAMERICAN ENERGY COMPANY

~~Wind VI~~	~~Walnut~~	~~52.5~~	~~35~~	~~GE 1.5sle~~	~~2008~~
~~Total~~		~~1059~~	~~706~~		

MIDAMERICAN ENERGY COMPANY

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 2 ~~Substitute 2nd~~3rd Revised Sheet No. 433.1
Filed with the Iowa Utilities Board Canceling ~~3rd Substitute 1st~~ 2nd Revised Sheet No. 433.1

CLAUSE EAC – ENERGY ADJUSTMENT (continued)

Ratemaking Principle Docket	Name of Wind Farm	MW	Number of Turbines	Model	
Wind VI	Walnut	52.5	35	GE 1.5sle	~~N~~L
Total		1059	706		~~N~~L
Wind IV	Adair	174.8	76	Siemens 2.3 93m	~~N~~
Wind VII	Rolling Hills	443.9	193	Siemens 2.3 101m	~~N~~
Wind VII	Pomeroy IV	29.9	13	Siemens 2.3 101m	~~N~~
Wind VII	Laurel	119.6	52	Siemens 2.3 101m	~~N~~
Wind VII	Vienna	105.6	45	Siemens 2.3 108m	~~N~~
Wind VII	Morning Light	101.2	44	Siemens 2.3 108m	~~N~~
Wind VII	Eclipse	200.1	87	Siemens 2.3 108m	
Total		1,175.1	510		

Ratemaking Principle Docket	Name of Wind Farm	MW	Number of Turbines	Model	
Wind II	Century	35	35	Mitsubishi MWT-100A	~~N~~
Wind II	Intrepid	15	15	Mitsubishi MWT-100A	~~N~~
Total		50	50		~~N~~

D = the monthly excess or deficiency which is entered into the cumulative account balance A

$$D = C_2 - [J_2 * (E_2 + B_2)]$$

Where subscripts are used to denote the applicable billing month or calendar month:

Subscript 2 means the second prior month.

E = monthly energy adjustment charge, calculated annually.

J = the jurisdictional electric energy consumed under rates set by the Iowa Utilities Board.

MIDAMERICAN ENERGY COMPANY
Electric Tariff No. 2
Filed with the Iowa Utilities Commission

~~13th~~ 14th Revised Sheet No. 434
Canceling ~~12th~~ 13th Revised Sheet No. 434

CLAUSE EAC – ENERGY ADJUSTMENT CLAUSE (continued)

APPLICABLE ANNUAL ENERGY ADJUSTMENT CLAUSE FACTOR:

Class	$/kWh	
All Rates	$ 0.00823 ~~0.00755~~	~~R~~ I

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79.

FUEL AND PURCHASED ENERGY CHARGE

The Forecasted System Average Fuel and Purchased Energy (FPE) Charge for each month shall be the forecasted FPE Charge for the current month divided by the forecasted Kilowatt-Hour Sales. The applicable Forecasted FPE Charge shall be added to customers' monthly bill according to each customer's rate class and Fuel and Purchased Energy Adjustment (FPEA) Factor.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending December 31 of each year as reported in the Annual Automatic Adjustment True-up report to be filed by March 1 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs to the forecasted costs and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under- recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each rate class shall be calculated as follows. The over- or under- recovery amount as shown in the current year Annual Automatic Adjustment True-up report will be divided by the forecasted Kilowatt-Hours subject to the fuel adjustment clause for the proposed twelve month recovery period the true-up rate will be in effect and then multiplied by the applicable FPEA Factor. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each rate class that will be applied to Customers' bills in the same manner as the forecasted monthly FPE Charge.

FORECASTED SYSTEM AVERAGE FUEL AND PURCHASED ENERGY CHARGE

The monthly Forecasted Average Fuel and Purchased Energy Charge shall be the **sum** of the following:

(a) The fossil and nuclear fuel forecasted to be consumed in Company's generating stations,

(b) The forecasted net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

energy is to be purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,

(c) The forecasted identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,

(d) The forecasted cost of steam from other sources to be used in the generation of electricity at the Company’s generating stations,

(e) The forecasted cost of the Released Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

(f) The forecasted cost of the Buyback Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,

(g) Forecasted fuel and purchased energy expenses to be incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691 excluding the cost of fuel and purchased energy related to meeting the Solar Energy Standard,

(h) All forecasted RTO (Regional Transmission Organization) energy market costs net of revenues, excluding administrative costs,

(i) The forecasted cost of the purchase of SO_2 and NOx allowances,

(j) The forecasted Time of Generation Adjustment as calculated in the Rider for Solar Energy Adjustment

(k) Reagent and chemical costs for environmental compliance

and **less**

(l) Forecasted revenues from the sale of SO_2 and NOx allowances,

(m) The forecasted cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis,

(n) Forecasted net revenues from the sale of environmental attributes from any Commission approved contract, and

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

(o) Forecasted net revenues (margins) from asset-based wholesale energy sales and capacity sales greater than three years.

The Forecasted Kilowatt-Hour Sales shall be Company's total forecasted kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (l) above and solar energy production and purchases referred to in (g) above.

FUEL AND PURCHASED ENERGY ADJUSTMENT (FPEA) FACTORS

A separate FPEA Factor shall be applied to calculate the Forecasted FPE Charge for each Rate Class. A Class Cost Factor shall be calculated for each Rate Class. For Residential Time-Of-Day (TOD) and Large Light & Power Time-Of-Use (TOU) customers a TOD or TOU Factor shall also be calculated for each TOD or TOU period. The FPEA Factor is the Class Cost Factor multiplied by the corresponding TOD or TOU Factor.

Rate Class	Class Cost Factor	TOD / TOU Factor	FPEA Factor
Residential	1.05841	1.00000	1.05841
Residential On-Peak	1.05841	1.17042	1.23878
Residential Off-Peak	1.05841	1.03330	1.09366
Residential Super Off-Peak	1.05841	0.75930	0.80365
General Service	1.02995	1.00000	1.02995
Large Light & Power	0.99451	1.00000	0.99451
Large Light & Power On-Peak	0.99451	1.17042	1.16399
Large Light & Power Off-Peak	0.99451	1.03330	1.02763
Large Light & Power Super Off-Peak	0.99451	0.75930	0.75513
Large Power	0.98328	1.00000	0.98328
Lighting	0.89264	1.00000	0.89264

2025 FORECASTED FPE RATE and 2023 TRUE-UP FPE RATE

The monthly forecasted 2025 FPE Rate was approved by the Minnesota Public Utilities Commission (“Commission”) Order issued on November 12, 2024, in Docket No. E015/AA-24-64.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

The 2023 FPE True-up Rate was approved in the Commission Order issued on July 1, 2024, in Docket No. E015/AA-22-216.

Applicable Month	FPE 2025 Forecasted Rate (¢/kWh)	FPE 2023 True-up Rate (¢/kWh)
January 2025	3.262	(0.133)
February 2025	3.105	(0.148)
March 2025	2.893	(0.140)
April 2025	2.883	(0.153)
May 2025	2.874	(0.149)
June 2025	2.784	(0.153)
July 2025	3.087	(0.144)
August 2025	3.267	(0.145)
September 2025	3.015	
October 2025	2.881	
November 2025	2.844	
December 2025	3.267	

A breakdown by month and Rate Class can be found on Minnesota Power’s website at https://www.mnpower.com/CustomerService/YourBill

ADJUSTMENT CLAUSE

1. The applicable energy or demand charges shall be increased or decreased quarterly, by an adjustment amount per kilowatt-hour of sales (to the nearest 0.001¢) or kilowatt of demand (to the nearest 1.0¢) equal to the difference between the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid, and Commission approved fuel incentives pursuant to SDCL 49-34A-25 ("qualified costs") per kilowatt-hour of sales or kilowatt of demand and the base cost per kilowatt hour or kilowatt included in applicable standard base rates, if any.

2. Qualified costs include:
   a. Delivered cost of energy:

      i. The net cost of energy delivered to the distribution system pursuant to filed wholesale transmission rates as recorded in Accounts 456 and 565 of the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees.

   b. Delivered cost of fuel:

      i. Fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus

      ii. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (b)(iii) below; plus

      iii. The net energy cost of energy purchases, including short-term capacity T
      purchases (one year or less) and exclusive of long-term capacity or T
      demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the utility to substitute for its own higher cost energy; and less

      iv. The cost of fossil and nuclear fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

      v. The cost of fossil fuel shall include those items listed in Account 151 of the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

(Continued)

(Continued)

vi. Revenue generated by the Sale of Renewable Energy Credits less expenses will be credited to customers.

vii. The cost of reagents and treated water used by the Company to operate its generating plants, in compliance with the associated United States Environmental Protection Agency rules and regulations.

viii. Production Tax Credits ("PTC's") provided by the generation of energy from the Company's Wind Generation Facilities. The Inflation Reduction Act of 2022 created the ability for utilities to monetize PTC's generated after 2022. PTC's generated after that date may be passed through the fuel tracker, net of the costs of transferability. T T T T T

c. Ad Valorem Taxes paid:
All ad valorem taxes accrued and adjusted for actual tax payments less recovery through (a) or (b) above, if any.

d. Commission approved fuel incentives:
All Commission approved incentives, if any, less recovery pursuant to (a), (b), or (c) above, if any.

3. Sales shall be all kilowatt hours sold, excluding inter-system sales. Sales shall be equated to the sum of generation, purchases, and interchange-in, less energy associated with pumped storage operations, less inter-system sales referred to in paragraph (2) (b) (iv) above, less system losses.

4. Variances in actual qualified costs incurred and costs recovered through the Adjustment Clause mechanism will be separately measured monthly for the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid, and South Dakota Public Utilities Commission approved fuel incentives. All accrued over or under variances shall be assessed a carrying charge or credit based upon the overall rate of return allowed by the South Dakota Public Utilities Commission in the Company's last general rate filing. Each applicable end-of-quarter true-up balance, adjusted for the next nine month's estimated over or under collection of cost, will be amortized into rates over the last twelve months of the subsequent thirteen month period.

SOUTH DAKOTA ELECTRIC RATE SCHEDULE

NORTHWESTERN ENERGY PUBLIC SERVICE CORPORATION d/b/a NORTHWESTERN ENERGY
SOUX FALLS Section 3
SOUTH DAKOTA 327th Revised Sheet No. 33a
Canceling 326th Revised Sheet No. 33a

ADJUSTMENT CLAUSE RATES

	Per KWH Per Month	
Delivered Cost of Energy - Energy Charge:		
Rate No. 10 - Residential Service	$0.00936	I
Rate No. 11 - Residential Service with Space Heating	$0.00936	I
Rate No. 14 - Residential Space Heating and Cooling	$0.00936	I
Rate No. 15 - Residential Dual Fuel and Controlled Services	$0.00936	I
Rate No. 16 - Interruptible Irrigation Service	$0.01019	I
Rate No. 17 - Irrigation Service	$0.01019	I
Rate No. 18 - Off Peak Irrigation Service	$0.01019	I
Rate No. 21 - General Service	$0.01019	I
Rate No. 23 - Commercial Water Heating	$0.01019	I
Rate No. 24 - Commercial Space Heating and Cooling	$0.01019	I
Rate No. 25 - All-Inclusive Commercial Service	$0.01019	I
Rate No. 41 - Municipal Pumping Service	$0.00854	I
Rate No. 70 - Controlled Off Peak Service	$0.00716	I
Rate No. 19 - Reddy-Guard, Rate No. 56 - Street and Area Lighting	$0.00936	I

	Per KW Per Month	
Delivered Cost of Energy - Demand Charge:		
Rate No. 33 - Commercial and Industrial Service	$2.20	I
Rate No. 34 - Large Commercial and Industrial Service	$2.20	I

(Continued)

SOUTH DAKOTA ELECTRIC RATE SCHEDULE

NORTHWESTERN ENERGY PUBLIC SERVICE CORPORATION d/b/a NORTHWESTERN ENERGY
SOUX FALLS Section 3
SOUTH DAKOTA 110th Revised Sheet No. 33b
Canceling 109th Revised Sheet No. 33b

ADJUSTMENT CLAUSE RATES (cont'd)

	Per KWH Per Month	
Ad Valorem Taxes Paid - Energy Charge		
Rate No. 10 - Residential Service	$0.00376	I
Rate No. 11 - Residential Service with Space Heating	$0.00376	I
Rate No. 14 - Residential Space Heating and Cooling	$0.00376	I
Rate No. 15 - Residential Dual Fuel and Controlled Services	$0.00376	I
Rate No. 16 - Interruptible Irrigation Service	$0.00408	I
Rate No. 17 - Irrigation Service	$0.00408	I
Rate No. 18 - Off Peak Irrigation Service	$0.00408	I
Rate No. 21 - General Service	$0.00408	I
Rate No. 23 - Commercial Water Heating	$0.00408	I
Rate No. 24 - Commercial Space Heating and Cooling	$0.00408	I
Rate No. 25 - All-Inclusive Commercial Service	$0.00408	I
Rate No. 41 - Municipal Pumping Service	$0.00345	I
Rate No. 70 - Controlled Off Peak Service	$0.00288	I
Rate No. 19 - Reddy-Guard, Rate No. 56 - Street and Area Lighting	$0.00381	I

	Per KW Per Month	
Ad Valorem Taxes Paid - Demand Charge:		
Rate No. 33 - Commercial and Industrial Service	$0.88	I
Rate No. 34 - Large Commercial and Industrial Service	$0.88	I

	Per KWH Per Month	
Delivered Cost of Fuel - All Energy Usage:		
All Rate Schedules	$0.02579	I

Service on or after
Date Filed: April 30, 2025 Effective Date: May 1, 2025
Issued By: Jeff Decker, Specialist Regulatory

FUEL CLAUSE CHARGE
There shall be added to or deducted from the monthly bill a Fuel Cost Charge calculated by multiplying the applicable monthly billing kilowatt hours (kWh) by the billed Fuel Adjustment Factor (FAF) per kWh. The billed FAF is calculated by prorating each calendar month FAF by the number of customer billing days in each calendar month, and rounding to the nearest $0.00001 per kWh.

EXEMPTION
For customers participating in Company's Renewable*Connect and Renewable*Connect Government pilot
programs, the Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex) or the Voluntary T
Renewable*Connect Program Rider (Long Term), the applicable billing kWh subject to the FAF shall be reduced T
by the elected Voluntary Renewable Adjustment energy blocks. In the event that a customer's metered energy use is lower than the subscribed energy blocks, the applicable billing kWh for the FAF for that month is zero.

For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the Fuel Clause Charge assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added back into the Current Period Cost of Energy applicable to the time period when the credit is issued.

FUEL ADJUSTMENT FACTOR (FAF)
A separate FAF will be determined for each service category defined by customer class and time-of-day (TOD) period within the Commercial and Industrial – Demand class. The FAF for each service category is the sum of the Current Period Cost of Energy multiplied by the applicable FAF Ratio, and the applicable Energy Cost True-up Factor. The FAF Ratio is the Class Cost Ratio multiplied by the corresponding TOD Ratio:

Service Category	Class Cost Ratio	TOD Ratio	FAF Ratio
Residential	1.0192	1.0000	1.0192
C&I Non-Demand	1.0183	1.0000	1.0183
C&I Demand	0.9917	1.0114	1.0030
C&I Demand TOD On-Peak	0.9917	1.2853	1.2746
C&I Demand TOD Off-Peak	0.9917	0.8068	0.8001
Outdoor Lighting	0.7659	1.0000	0.7659
C&I Demand TOU Pilot Peak	0.9917	1.3341	1.3230
C&I Demand TOU Pilot Base	0.9917	1.0754	1.0665
C&I Demand TOU Pilot Off-Peak	0.9917	0.5283	0.5239

(Continued on Sheet No. 5-91.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
35th Revised Sheet No. 91.1

FUEL COST FACTORS (2025)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Off-Peak	Outdoor Lighting	
January	$0.02617	$0.02615	$0.02576	$0.03272	$0.02056	$0.01968	
February	$0.02819	$0.02817	$0.02774	$0.03525	$0.02213	$0.02119	
March	$0.02919	$0.02916	$0.02873	$0.03651	$0.02291	$0.02193	
April	$0.00972	$0.00970	$0.00955	$0.01215	$0.00763	$0.00730	R
May	$0.02618	$0.02616	$0.02577	$0.03273	$0.02057	$0.01969	
June	$0.02839	$0.02837	$0.02793	$0.03551	$0.02228	$0.02133	
July	$0.02787	$0.02783	$0.02742	$0.03487	$0.02185	$0.02092	
August	$0.02617	$0.02615	$0.02576	$0.03275	$0.02053	$0.01965	
September	$0.02300	$0.02299	$0.02264	$0.02878	$0.01805	$0.01728	
October	$0.02099	$0.02097	$0.02066	$0.02626	$0.01648	$0.01578	
November	$0.01839	$0.01837	$0.01809	$0.02300	$0.01442	$0.01381	
December	$0.02055	$0.02052	$0.02021	$0.02569	$0.01612	$0.01543	R

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	$0.03396	$0.02738	$0.01348	
February	$0.03659	$0.02950	$0.01450	
March	$0.03789	$0.03055	$0.01500	
April	$0.01260	$0.01017	$0.00499	R
May	$0.03398	$0.02740	$0.01347	
June	$0.03686	$0.02970	$0.01458	
July	$0.03620	$0.02916	$0.01428	
August	$0.03399	$0.02740	$0.01343	
September	$0.02987	$0.02407	$0.01181	
October	$0.02726	$0.02197	$0.01079	
November	$0.02387	$0.01925	$0.00945	
December	$0.02666	$0.02149	$0.01055	R

CURRENT PERIOD COST OF ENERGY
The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

5. The energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, and the net cost of energy (and capacity if purchased on an energy output basis) purchases from any qualifying facility using wind energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis. Capacity costs associated with such purchased power contracts, which are in excess of 100 kW and commenced after the date of the Commission's final order in Docket No. E002/GR-05-1428, shall be excluded from Fuel Cost Charge recovery.

6. Less the fuel-related costs recovered through intersystem sales.

7. Less purchased power costs for the Renewable*Connect, Renewable*Connect Government pilot programs, the Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and the Voluntary T
Renewable*Connect Program Rider (Long Term) as recorded in FERC account 555. T

8. Less neutrality charge cost recovery for the Renewable*Connect and Renewable*Connect Government pilot programs.

9. Less asset based margins from intersystem sales of excess generation and ancillary services. Asset based margins are defined as sales revenues less the sum of fuel and energy costs (including costs associated with MISO Day 2 markets that are booked to FERC Account 555) and any additional transmission costs incurred that are required to make such sales.

ENERGY COST TRUE-UP FACTORS

An Energy Cost True-up Factor per kWh is calculated annually for each Class and TOD category by dividing the Energy Cost True-up Amount by the qualifying kWh sales forecasted for the proposed period of up to twelve months the rate will be in effect and then multiplied by the applicable FAF ratio. The application of true-up factors to customers' bills is subject to Commission approval.

(Continued on Sheet No. 5-91.3)

RATE SCHEDULES BY SERVICE CATEGORY

Residential
Residential (A00, A01, A03)
Residential TOD (A02, A04)
Residential TOU Pilot Program (A72, A74)
Energy Controlled (A05)
Limited Off-Peak (A06)
Residential Electric Vehicle (A08)
Residential Electric Vehicle Pilot (A80, A81)
Residential Electric Vehicle Subscription Pilot (A82, A83)

Commercial and Industrial Non-Demand
Energy Controlled (A05)
Limited Off Peak (A06)
Small General (A09, A10, A11, A13)
Small General TOD (A12, A16, A18, A22)
Small Municipal Pumping (A40)
Fire and Civil Defense Siren (A42)
Multi-Dwelling Unit Electric Vehicle Service Pilot (A91, A92, A93)
Electric Service Public Charging Station Pilot (A94) N

Commercial and Industrial Demand – Non-TOD
General (A14)
Peak Controlled (A23)
Municipal Pumping (A41)

Commercial and Industrial Demand – TOD
General TOD (A15, A17, A19)
Peak Controlled TOD (A24)
Tier 1 Energy Controlled Rider (A27)
Light Rail Line (A29) D
General TOU Pilot Program (A25, A26)
Electric Vehicle Fleet Pilot (A87, A88, A89) N
Electric Vehicle Public Charging Pilot (A90) N

Outdoor Lighting
Automatic Protective (A07)
Street Lighting System (A30)
Street Lighting Energy (Closed) (A32)
Street Lighting Energy – Metered (A34)
Street Lighting - City of St. Paul (A37)

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on May 1st a 24-month forecast of the fuel and purchased energy costs applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

EXCLUSION OF COMMUNITY SOLAR GARDEN COSTS

To comply with Minn. Stat. § 216B.1641, Subd. 11, the fuel adjustment charge to residential customers who have received bill payment assistance or income-qualified energy assistance programs within the proceeding twelve-month timeframe and who also do not subscribe to a community solar garden shall exclude the “net cost of community solar garden generation”. To achieve this exclusion, these customers shall receive a bill credit of $0.00681 per kWh of billed usage that removes “net cost of community solar garden generation”.

R
D
D
D

EFFECTIVE IN: All territory served.

APPLICABILITY: This rider is applicable to and becomes a part of each Oklahoma retail rate schedule unless specifically excluded.

FUEL COST ADJUSTMENT: The monthly bill as calculated under the stated rates shall be increased for each kilowatt-hour (kWh) consumed by an amount computed in accordance with the following formula:

Semi-Annual Service Level Fuel Cost = FC + TUA

Where: FC = The service level semi-annualized cost of fuel which reflects the applicable seasonal cost differences. The cost shall be the Oklahoma retail share of fuel including Air Quality Controls Systems (AQCS) consumables, Off-System Sales fuel costs, revenue credits and purchased power expense. Purchased power expense includes Southwest Power Pool (SPP) Integrated Marketplace (IM) activity. Revenue credits include Off-System Sales revenue and 80% of any Renewable Energy Certificates (REC) sales.

TUA = True-up adjustment for the prior cost period.

Where: FC = (VFC x SLEAF) + (FFC x SLPA) + OJC.

VFC = The variable costs of fuel, AQCS, SPP IM and purchased power including revenue credits. Variable fuel, AQCS and purchased power costs are recorded in accounts 501, 502, 547, 548, and 555. Revenue credits are recorded in accounts 447, and 456.

SLEAF = Service level energy allocation factor calculated by dividing the service level kWh sales adjusted for losses by the total system sales adjusted for losses (losses are calculated based on the latest loss study).

FFC = Fixed fuel costs including gas transportation, gas storage, and other coal and gas costs.

SLPA = Service level production allocator from last approved cost of service study.

OJC = Oklahoma jurisdiction costs that are to be collected from only the Oklahoma customers. These costs also consist of free service, price response credits and certain wind purchased power costs. These costs are credited for appropriate SPP IM sales. These variable or fixed costs will be allocated to service levels using the SLEAF or the SLPA allocators (rebased to one hundred percent).

Then:

TUA = True-up adjustment is the sum of each service level monthly over-or-under collected amounts (MOU) for the prior cost period.

Where:

MOU = [MFC – (MFR – PTU)] + UA + CC

MFC = The monthly service level fuel cost (FC) as calculated above.

MFR = Monthly service level fuel revenue collected under the FCA.

PTU = The prior period true-up adjustment which is one twelfth of the TUA from the prior cost period.

UA = Service level specific fuel and energy portion of Uncollectible Accounts.

CC = (BB + EB)/2 * CCR * (Days in cost month/365)

Where:

CCR = The Carrying Charge Rate which is the current Oklahoma Corporation Commission approved interest rate for customer deposits held one year or less.

BB = Beginning monthly over/under recovery Balance for the current month energy cost period excluding carrying charges.

EB = Ending monthly over/under recovery Balance for the current month energy cost period excluding carrying charges.

The prior cost period is for the previous Winter or Summer factor months.

FCA_w = Winter per kWh fuel cost rate for all tariffs. (November through May)

$$FCA_w = \frac{FC_w}{S_w}$$

Where: FC_w = The winter season portion of the Annual Service Level Fuel Cost .

S_w = The service level winter season Oklahoma retail kWh sales subject to the Fuel Cost Adjustment.

FCA_s = Summer per kWh fuel cost rate for standard tariffs. (June through October)

$$FCA_s = \frac{FC_s}{S_s}$$

Where: FC_s = The summer season portion of the Annual Service Level Fuel Cost.

S_s = The service level summer season Oklahoma retail kWh sales subject to the Fuel Cost Adjustment for all rates.

FCA_{on} = Summer on-peak period fuel cost per kWh

Where: FCA_{on} = The forecasted incremental cost adjusted for service level losses.

FCA_{off} = Summer off-peak period fuel cost per kWh

$$FCA_{off} = \frac{((FCA_s * (S_{on} + S_{off})) - (FCA_{on} * S_{on})}{S_{off}}$$

Where: FCA_s = Summer per kWh fuel cost rate for standard tariffs.

S_{on} = The service level summer on-peak period Oklahoma retail kWh sales subject to the Fuel Cost Adjustment.

S_{off} = The service level summer off-peak period Oklahoma retail kWh sales subject to the Fuel Cost Adjustment.

Rates Authorized by the Oklahoma Corporation Commission:

(Effective)	**(Order No.)**	**(Case No.)**
June 1, 2025	748855	PUD 2024-000038
January 1, 2025	745601	PUD 2023-000087
May 1, 2023	733777	PUD 2022000057
October 1, 2022	728277	PUD 202100164

Public Utilities Division Stamp

APPROVED
May 21, 2025
DIRECTOR
of
PUBLIC UTILITY DIVISION

INTERIM RATE ADJUSTMENT: The semi- annual service level cost per kWh may be adjusted at the request of either the Commission Staff or the Company when the cumulative over-or-under collected balance for the rider applicable period is greater than $50,000,000. This interim adjustment amount may include the monthly over-or-under collected amounts (differences between the fuel collected in tariffs and the actual fuel expense incurred) that have occurred in the rider applicable period. Any over/under collected balance greater than $50,000,000 accruing since the most recent change in FCA factors shall be amortized over a period no less than 6 months and may be extended beyond 6 months on a case by case basis. The Commission Staff and the parties of record in the Company's most recent base rate case proceeding shall be notified prior to any change and the Company shall provide the Commission Staff and the parties of record in the Company's most recent base rate case proceeding the information supporting such adjustments, subject to any protective order issued by the Commission.

Stipulating Parties shall be notified at least 15 days prior to the proposed implementation date of an interim adjustment to FCA charges, and the Company shall provide the PUD and Stipulating Parties the information supporting such proposed adjustment at the time notice of the proposed interim adjustment is provided. The Company will also facilitate a meeting with PUD and Stipulating Parties no later than 10 days prior to the proposed effective date of any interim adjustment to FCA charges to explain and answer questions regarding the Company's redetermined factors. The Public Utility Division shall review and approve or deny any requested interim FCA adjustments. If approved, the change will become effective with the first billing cycle of the month subsequent to the approval.

Day-Ahead Pricing and Flex Price: The Fuel Cost Adjustment factors will not apply to the Day-Ahead Pricing (DAP) and Flex Price (FP) customer kWh sales above Customer Baseline Loads. All DAP and FP kWh sales above Customer Baseline Load and associated fuel costs will be excluded from the Fuel Cost Adjustment calculations above.

Off System Sales Of Electricity: One hundred percent (100%) of the Oklahoma jurisdictional share of the net profit from sales will be included in the Fuel Cost Adjustment. The net earnings (or profits) derived from such sales will be the difference between the sales price of the electricity and ancillary services delivered and all costs associated with such sales of electricity and services excluding variable production operation and maintenance expenses.

Semi-Annual Redetermination: Beginning on June 1, 2025, the Company will begin adjusting its FCA factors on a semi-annual basis (on November 1st and June 1st). At least 21 days prior to November 1st and June 1st of each year, the Company will submit to the Commission Staff and all other parties of record in the Company's most recent base rate case proceeding the re-determined FCA factors for each service level to be effective the first billing cycle in November and June and the Company shall also provide information supporting such re-determined factors, subject to any protective order issued by the Commission. The Company will also facilitate a meeting with the parties of record in Cause No. PUD 202100164 to explain and answer questions regarding the Company's re-determined factors and may update the proposed factors and supporting information within 15 days prior to November 1st or June 1st. The Public Utility Division shall review and approve or deny any requested semi-annual FCA adjustments. If approved, the change will become effective with the first billing cycle of the month subsequent to the approval.

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

15th Revised Sheet No. 50.85
Replacing 14th Revised Sheet No. 50.85
Date Issued November 26, 2024

STANDARD PRICING SCHEDULE: FCA
STATE OF OKLAHOMA
RIDER FOR FUEL COST ADJUSTMENT

FCA Factors

	Service Level				
	1	2	3	4	5
2025					
Winter (Jan-Feb)	$0.020141	$0.020535	$0.022418	$0.024548	$0.027750
Winter (Mar-May)	$0.030633	$0.032428	$0.035130	$0.034985	$0.039252
Summer (June - Oct)					
Non-Tou	$0.035440	$0.039861	$0.041454	$0.042576	$0.044586
TOU-On Peak	$0.046511	$0.046687	$0.047909	$0.048646	$0.048980
TOU-Off Peak	$0.034093	$0.038974	$0.040584	$0.041697	$0.043988

Rates Authorized by the Oklahoma Corporation Commission:

(Effective)	(Order No.)	(Case No.)
June 1, 2025	745601	PUD 2023-000087
March 1, 2025	745601	PUD 2023-000087
January 1, 2025	745601	PUD 2023-000087
November 1, 2024	733777	PUD 2022000057

Public Utilities Division Stamp

APPROVED
May 21, 2025
DIRECTOR
of
PUBLIC UTILITY DIVISION

ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY

(Identified on the bill as Fuel & Purchase Power) N

ENERGY ADJUSTMENT CHARGE: There shall be added to the monthly bill an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing Kilowatt hours (kWh) by the customers applicable billed Energy Adjustment Factor (EAF) per kWh. The billed EAF amount per Kilowatt-hour (rounded to the nearest 0.001¢) will be the average monthly cost of Energy per Kilowatt-hour as determined for that customers service category. The average cost of Energy per Kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent four-month period as follows: C C C C

Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative Energy costs divided by retail sales for actual months 1, 2, 3, and 4 equals the cost of Energy adjustment for month 6.

ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each Customer service category defined by Customer class. The EAF for each service category is the sum of the Current Period Average Cost of Energy and applicable monthly true-up, multiplied by the applicable EAF Ratio. The applicable EAF for each calendar month will be applied to that calendar month's daily pro-ration of Energy usage included on the bill.

Service Category	Section	EAF Ratio	
Residential	9.01, 9.02,	1.077	**R**
Farm	9.03	1.008	**R**
General Service	10.01, 10.02, 10.03	1.061	**R**
Large General Service	10.04, 10.05, 10.06, 11.01, 14.13	0.961	**R**
Irrigation Service	11.02	0.954	**R**
Outdoor Lighting	11.03, 11.04, 11.07	0.908	**R**
OPA	11.05	1.031	**R**
Controlled Service Deferred Load	14.01, 14.06	0.973	**CR**
Controlled Service Interruptible	14.04, 14.12	0.985	**CR**
Controlled Service Off-Peak	14.07	1.054	**CR**

The average cost of Energy shall be determined as follows: **L**

1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants, and the costs of reagents and emission allowances for the Company to operate its generating plants in compliance with the associated Federal Environmental Protection Agency rules and regulations. Energy from the Company's hydro generating plants shall be included at zero cost. **L L L**

2. The Energy cost of purchased power included in Account 555 when such Energy is purchased on an economic dispatch basis, exclusive of Capacity or Demand charges. This includes but is not limited to net costs linked to the utility's load serving obligation, associated with participation in wholesale electric Energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the Energy markets. All Midcontinent Independent System Operator ("MISO") Energy and Ancillary service market charges and credits relating to retail sales and asset based sales, specifically including (but not limited to) Schedule 16 and 17 charges and credits shall be included in the calculation.

3. The actual identifiable fossil and nuclear fuel costs associated with Energy purchased for reasons other than identified in 2 above.

4. The net Energy cost of Energy purchases from a renewable Energy source, including hydropower, wood, windpower, and biomass.

5. Less the fuel-related costs recovered through intersystem sales.

6. The Energy cost of avoided purchased power resulting from Hoot Lake Solar output.

7. Known MISO Planning Resource Auction capacity costs will be added to the energy adjustment rider or revenues will be credited (flow through) the energy adjustment rider.

8. All revenues and associated costs attributable to Asset-based Sales Margins, as defined below and in the amount calculated as described below, shall be included in the Energy adjustment calculation described in this schedule.

Asset-based Sales Margins:

Asset-based Sales Margins are defined as wholesale Energy and ancillary services sales revenues from Company-owned generation resources less the sum of fuel, Energy costs (including costs associated with MISO markets that are recorded in FERC Account 555), and any additional transmission or other costs incurred that are required to make such sales (referred to as “margins”). One hundred percent of these actual revenues and costs shall be included in the energy adjustment rider as they are incurred.

9. The costs of fuel and reagents resulting from steam and water sales and the revenues from **N**
steam and water sales shall be included in the energy adjustment rider. **N**

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be **N**
modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the **N**
Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the **N**
North Dakota electric rates for the matrices of riders. **N**

SCHEDULE: FUEL COST ADJUSTMENT RIDER (FCA)

AVAILABILITY

This Rider is applicable to and becomes a part of each OCC jurisdictional rate schedule in which reference is made to Fuel Cost Adjustment (FCA).

FUEL COST ADJUSTMENT

The Fuel Cost Adjustment shall be calculated by multiplying the total retail billing kilowatt-hours (kWh) by the Service Level Fuel Cost Adjustment Factor for the current billing period. The Service Level Fuel Cost Adjustment Factor shall be determined on a semi-annual basis and become effective with the first billing cycle of May and November in the following manner:

$$FA = \frac{FUEL\$}{S} + DEF\$$$

WHERE:

FA = The Service Level Fuel Cost Adjustment Factor (expressed in dollars per kWh) to be applied per kWh consumed.

DEF$ = The retail service level prior month's balance sheet amount for the Unrecovered Fuel Cost divided by the service level annual retail kWh sales.

S = Retail service level kWh sales for the period adjusted for any directly assigned fuel kWh subject to the Fuel Cost Adjustment rider.

FUEL$ = ((SYS$ + PPE$ + PTC$ + PTC$TU + DTA$ - OSEC) x ((S x SLEF)/U)) + ((REC$ + GTD$ + PPD$) x SLPDA)

WHERE:

SYS$ = The OCC allowable fuel expense for the period shall be the fuel expense properly recorded in the FERC Account 5010 and FERC Account 5470, along with environmental consumables expenses properly recorded in subaccounts of FERC Accounts 502, 509 and 548. This value will be adjusted to remove any fuel expense incurred to supply off-system sales.

PPE$ = The energy cost of purchased power for the period shall be the energy-related purchased power expense properly recorded in FERC Account 5550. The purchased power energy cost shall also include the energy-related cost of power purchased from customers, cogeneration and small power production facilities, along with energy-related costs and credits associated with Southwest Power Pool Integrated Market (SPP IM) transactions as recorded in FERC Account 5550. This value will be adjusted to remove any energy-related purchased power costs incurred to supply off-system sales.

PTC$ = Estimated net proceeds realized from Federal Production Tax Credits during the applicable calendar year from the approved renewable facilities authorized for recovery through rates, with a tax gross up.

PTC$TU = The True-up amount will be the difference between the net proceeds realized from Actual Federal Production Tax Credits less the estimated Federal Production Tax Credits reflected in the FCA factors in the prior calendar year.

DTA$ = Debt return on the monthly deferred tax asset balance resulting from the unused Selected Wind Facilities Production Tax Credits properly recorded in FERC Accumulated Deferred Income Taxes accounts as approved in Cause No. PUD 202000104.

OSEC = 100% of the margin from off-system sales of electricity and 75% of the margins from standby service.

S = Retail service level kWh sales for the period adjusted for any directly assigned fuel kWh.

SLEF = The service level expansion factor from the most recent line loss study.

U = Total system service level kWh sales at the generator by the Company for the period adjusted for any directly assigned fuel kWh. The OCC jurisdictional amount is defined as OCC jurisdictional kWh sales divided by total company sales exclusive of off-system sales (net system sales).

REC$ = Net proceeds from the sales of Renewable Energy Credits.

GTD$ = The gas transportation and agency expense plus other fixed fuel costs properly recorded in FERC Account 5010.

PPD$ = The capacity cost of purchased power for the period shall be the capacity- or demand-related purchased power expense properly recorded in FERC Account 5550. The purchased power cost shall also include the capacity- or demand-related cost of power purchased from customers, cogeneration and small power production facilities, along with capacity- or demand-related costs and credits associated with SPP IM transactions as recorded in FERC Account 5550. This value will be adjusted to remove any capacity- or demand-related purchased power costs incurred to supply off-system sales.

SLPDA = The service level production demand allocator from the most recent cost of service study.

SEMI-ANNUAL RE-DETERMINATION

No later than 45 days before the first billing cycle of May and November, the Company will submit to the Commission Staff, and all other parties who request the information and who abide by the approved confidentiality processes, the re-determined FCA factors for each service level along with information supporting the calculation and expense underlying such re-determined factors. The Company will also facilitate a meeting with the interested parties of record in Case No. PUD 2023-000086 to explain and answer questions regarding the Company's re-determined factors no later than 15 days before the proposed new rates are expected to be placed into effect.

SUCCESSOR ACCOUNTS AND SUBACCOUNTS

Successor accounts and subaccounts may be included as appropriate following advance notification to the Oklahoma Corporation Commission, Director of Public Utilities.

INTERIM ADJUSTMENT OF FUEL COST ADJUSTMENT FACTOR

In the event that the semi-annual fuel cost adjustment factor over/under-recovered balance is $50,000,000 or more on a cumulative basis for the rider applicable period, the Company or the Commission Staff may request approval of an interim adjustment to the semi-annual FCA. This interim adjustment amount may include the monthly over-or-under collected amounts (differences between the fuel collected in tariffs and the actual fuel expense incurred) that have occurred in the rider applicable period. Any over/under collected balance greater than $50,000,000 accruing since the most recent change in FCA factors shall be amortized over a period no less than 6 months and may be extended beyond 6 months on a case by case basis. The Company shall notify and provide information supporting proposed interim adjustments to the Commission Staff and the interested parties as set forth above no later than 21 days before such changes are expected to be placed into effect. The Company will also facilitate a meeting with the interested parties of record in Case No. PUD 2023-000086 to explain and answer questions regarding the Company's re-determined factors no later than 10 days before the proposed new rates are expected to be placed into effect. The Director of the Public Utility Division shall review and approve or deny any requested interim FCA adjustments. If approved, the change will become effective with the first billing cycle of the month subsequent to the approval.

MONTHLY RATES

Service Level 1	Service Level 2	Service Level 3	Service Level 4/5/6
0.032995	0.033249	0.034263	0.039772

ARKANSAS PUBLIC SERVICE COMMISSION

First Revised	Sheet No. R-27.1	Sheet 1 of 9	
Replacing: Original	Sheet No. R-27.1		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 27			
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)			PSC File Mark Only

RECOVERY OF ENERGY COST

Energy Cost Recovery Rider ("Rider ECR ") defines the procedure by which the "Energy Cost Rate" of Southwestern Electric Power Company ("SWEPCO" or "Company") shall be initially established and periodically redetermined. The Energy Cost Rate shall recover the Company's net fuel, purchased energy cost, and short-term Capacity Purchase Agreements (CPAs) as defined in this Rider ECR.

ENERGY COST RATE

The Energy Cost Rate shall be redetermined annually through filings made in accordance with the provisions of Annual Redetermination of this Rider ECR. The Energy Cost Rate shall be applied to each customer's monthly billing energy (kWh). For electric service billed under applicable rate schedules for which there is no metering, the monthly usage shall be estimated by the Company and the Energy Cost Recovery Rider shall be applied. The Energy Cost Rate shall be calculated to the nearest $0.000001 and when applied to customers' bills shall be rounded to the nearest cent.

ANNUAL REDETERMINATION

On or before March 15 of each year the Company shall file a redetermined Energy Cost Rate with the Arkansas Public Service Commission (APSC or Commission). The redetermined Energy Cost Rate shall be determined by application of the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Each such revised Energy Cost Rate shall be filed in the proper underlying docket and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the revised Energy Cost Rate.

ARKANSAS PUBLIC SERVICE COMMISSION

First Revised	Sheet No. R-27.2 Sheet 2 of 9	
Replacing: Original	Sheet No. R-27.2	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

The redetermined Energy Cost Rate shall reflect the projected Energy Cost for the 12-month period commencing on April 1 of each year ("Projected Energy Cost Period"), a true-up adjustment reflecting the over-recovery or under-recovery of the Energy Cost for the 12-month period ended December 31 of the prior calendar year ("Historical Energy Cost Period"), and an estimate of the Arkansas over/under for period between December 31 of the prior year and the Projected Energy Cost Period commencing on April 1 (January 1 – March 31). The Energy Cost Rate so determined shall be effective for bills rendered on and after the first billing cycle of April of the filing year and shall then remain in effect for twelve (12) months, except as otherwise provided for below.

The annual update shall include a report of the following:

1. detailed fuel, purchased energy costs, and CPAs by FERC account and month for the historical year;
2. identify and explain changes from the prior year for major cost components of the ECR Rider, including fuel expense, purchased energy expense, CPAs, off-system sales margins, etc., of 10% or more;
3. identify changes in accounting procedures affecting fuel, ~~and~~ purchased power costs, and CPAs such as changes in FERC account number classifications and changes in costing methodologies;
4. identify changes in fuel, purchased power, and CPA procurement practices;
5. identify the monthly level of coal inventory in days and tons for the historical year;
6. identify the average price per unit for each fuel type and purchased power for the historical year;
7. identify revisions to the AEP System Integration Agreement affecting fuel and purchased energy costs;
8. identify and discuss changes in environmental regulations affecting fuel, purchased energy, and CPA costs and explain the Company's plans for compliance;
9. identify plant outages for the historical year and explain the cause(s) of the outages; and

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

First Revised	Sheet No. R-27.3 Sheet 3 of 9	
Replacing: Original	Sheet No. R-27.3	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

10. provide the summation of all day-ahead and real-time transactions, centered around the SPP energy market, and forward transactions, which will be made outside the SPP energy market beyond the day-ahead time horizon for each month in the preceding calendar year;

11. identify penalty charges received in the SPP IM, if any, for the historical year and explain the reasons for incurring such penalties;

12. identify and explain changes in the SPP IM or the application of the SPP tariff that affect fuel and fuel-related costs and revenues recovered in the Rider ECR;

13. explain SWEPCO's process for evaluating the accuracy of the underlying costs from the SPP IM;

14. identify the remaining balance of the extraordinary fuel costs and discuss any changes that impacted the remaining balance outside of revenues applied, including but not limited to, further SPP reconciliations and prudence findings~~.~~; and

15. identify new CPAs.

ADJUSTMENTS

If prior to the annual redetermination of the Energy Cost Rate, Staff or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the Company's Energy Cost, either the Staff or the Company may propose an adjustment to the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Furthermore, should a cumulative over-recovery or under-recovery balance arise during any Rider Cycle which exceeds ten percent (10%) of the Historical Energy Cost Period, then either the APSC General Staff ("Staff") or the Company may propose an interim revision to the then currently effective Energy Cost Rate.

PAYMENT FOR SERVICE

Payment for Service Rider – See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-27.4	Sheet 4 of 9
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A

ENERGY COST RATE FORMULA

ECR = ENERGY COST RATE

$$ECR = \frac{TUA + (PEC) + STP + DEFCON + M + DH + WS + DHM}{PES} * LCF$$

WHERE,

$$TUA = \sum_{j=1}^{15} ((((EC_j * JAF) - ((NCW_j + PTC\$_j) * NCWJAF)) - (RR_j - PTUj)))) + CC_j + WCC_j$$

Where,

EC_j = *ENERGY COST FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD (1)*

$$EC_j = Fe_j + Pe_j - OST_j + AR\ ADJ_j - ALLOWREV_j - REC_j$$

Where

Fe_j = *FUEL EXPENSE CHARGED TO ACCOUNT 501 PLUS LIMESTONE, ACTIVATED CARBON, CALCIUM BROMIDE, HYDRATED LIME, AND UREA EXPENSE CHARGED TO ACCOUNT 502 PLUS SO_2 AND NO_X EMISSION COSTS CHARGED TO ACCOUNT 509 (8, 10)*

ARKANSAS PUBLIC SERVICE COMMISSION			
Second Revised	Sheet No. R-27.5	Sheet 5 of 9	
Replacing: First Revised	Sheet No. R-27.5		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 27			
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)			PSC File Mark Only

ATTACHMENT A (continued)

Pe_j	=	*PURCHASED ENERGY EXPENSE, CHARGED TO ACCOUNTS 555 including expenses for CPAs incurred after the date of April 1, 2025, LESS THE TOLEDO BEND PROJECT – SABINE RIVER AUTHORITY PURCHASED ENERGY EXPENSE*
NCW_j	=	*NORTH CENTRAL ENERGY FACILITY (NCEF) SPP REVENUES AND EXPENSES NET BENEFIT PLUS PROCEEDS FROM THE SALES OF NCEF RENEWABLE ENERGY CREDITS*
$PTC\$_j$	=	*FEDERAL PRODUCTION TAX CREDITS RECORDED BY SWEPCO DURING THE APPLICABLE CALENDAR YEAR FROM THE SELECTED WIND FACILITIES, NET OF TRANSFER COSTS, WITH A TAX GROSS UP INCLUDING ANY TRUE-UPS TO PRIOR YEARS.*
OST_j	=	*MARGINS FROM OFF-SYSTEM SALES TRANSACTIONS RECORDED IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD (2) EXCLUDING NCEF SPP REVENUES AND EXPENSES*
$AR\ ADJ_j$	=	*ADJUSTMENT FOR REMOVAL OF TURK PLANT EXPENSES AND REVENUES BECAUSE THE TURK PLANT DOES NOT SERVE ARKANSAS LOAD (9)*
$ALLOWREV_j$	=	*REVENUES ASSOCIATED WITH SALES OF SO_2 AND NO_X EMISSIONS ALLOWANCES RECORDED IN ACCOUNT 4118 AND REVENUES RECEIVED FROM THE SALE OF RENEWABLE ENERGY CREDITS,*
REC_j	=	*PROCEEDS FROM THE SALES OF RENEWABLE ENERGY CREDITS NOT FROM NCEF*

JAF = JURISDICTIONAL ALLOCATION FACTOR (3)

NCWJAF = NCEF JURISDICTIONAL ALLOCATION FACTOR (3)

RR_j = *REVENUE UNDER RIDER ECR FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-27.6 Sheet 6 of 9	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A (continued)

PTU_j = PRIOR PERIOD TRUE-UP ADJUSTMENT APPLICABLE FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

CC_j = CARRYING CHARGES FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

$$CC_j = (BB_j + EB_j)/2 * CCR * DAYS_j/365$$

WHERE,

BB_j = BEGINNING MONTH OVER/UNDER-RECOVERY BALANCE, EXCLUDING CARRYING CHARGES, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

EB_j = ENDING OVER/UNDER-RECOVERY BALANCE, EXCLUDING CARRYING CHARGES, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

CCR = CARRYING CHARGE RATE (4)

$DAYS_j$ = NUMBER OF DAYS IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD

WCC_j = CARRYING CHARGES FOR MONTH j CALCULATED ON WS IN THE SAME MANNER DESCRIBED FOR CC_j EXCEPT USING SWEPCO'S APPROVED RATE OF RETURN FOR CCR AS APPROVED IN ORDER NUMBER 21 IN DOCKET 19-008-U

PEC = ESTIMATED ARKANSAS ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (5)

$$PEC = \sum_{j=1}^{12} EC_j$$

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-27.7 Sheet 7 of 9	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A (continued)

M = *$1,558,347 OF PROJECTED FINAL MINE CLOSING AND RECLAMATION COSTS FOR SWEPCO'S PIRKEY POWER PLANT. THE ANNUAL AMOUNT WILL BE RECOVERED EFFECTIVE APRIL 1, 2022 THROUGH MARCH OF 2023. THE AMOUNT COLLECTED IS SUBJECT TO FINAL TRUE-UP BASED ON FINAL RECLAMATION COSTS AT THE END OF THE RECLAMATION TERM.*

DH = *AMORTIZATION OF ARKANSAS DOLET HILLS FUEL EXPENSE OF $20,463,795 OVER 5 YEARS ($20,463,795/5 = $4,092,759 PER YEAR) EFFECTIVE APRIL 1, 2021.*

DHM = *TRUE-UP OF FINAL MINE CLOSING AND RECLAMATION COSTS FOR SWEPCO'S DOLET HILLS POWER PLANT. THE AMOUNT COLLECTED IS SUBJECT TO FINAL TRUE-UP BASED ON FINAL RECLAMATION COSTS AT THE END OF THE RECLAMATION TERM.*

WS = *AMORTIZATION OF 2021 WINTER STORM ENERGY COSTS OVER 73 MONTHS (CARRYING COST ACCRUED MARCH 2021 WITH RECOVERY BEGINNING APRIL 2021), ADJUSTED FOR ANY SPP OR OTHER RECONCILIATION AND SUBJECT TO FINAL PRUDENCE REVIEW AND APPROVAL BY THE COMMISSION*

LCF = *LOSS CORRECTION FACTOR (6)*

PES = *PROJECTED SALES (kWh) SUBJECT TO THIS RIDER ECR FOR THE PROJECTED ENERGY COST PERIOD*

STP = *ESTIMATED OVER/UNDER RECOVERY FOR THE PERIOD BETWEEN DECEMBER 31 OF THE PRIOR YEAR AND THE PROJECTED ENERGY COST PERIOD COMMENCING ON APRIL 1 (JANUARY 1 – MARCH 31)*

DEFCON=AMORTIZATION OF DEFERRED CONSUMABLES ASSOCIATED WITH APSC DOCKET NO. 14-080-U (7)

ARKANSAS PUBLIC SERVICE COMMISSION			
1st Revised	Sheet No. R-27.8	Sheet 8 of 9	
Replacing: Original	Sheet No. R-27.8		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 27			
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)			PSC File Mark Only

ATTACHMENT A (continued)

(1) The Historical Energy Cost Period is the calendar year immediately preceding the filing year.

(2) The margins from off-system sales transactions shall be treated in the following manner:

Customers shall be credited with 100% of the off-system sales margins allocated to SWEPCO's Arkansas retail jurisdiction Arkansas retail customers shall be shielded from any overall net annual loss from off-system sales transactions that may occur. In any year when the net margins from off-system sales result in a loss, such losses shall be borne by SWEPCO.

Treatment of Affiliated Sales Margins
Margins allocated to SWEPCO's Arkansas retail jurisdiction resulting from capacity sales will be reflected in the calculation of the Energy Cost Recovery Rider.

(3) The jurisdictional allocation factor will be derived in a two step process. First, for each jurisdiction the voltage level kWh at the meter will be divided by the most recent energy loss factors to determine the voltage level kWh at generation. Second, the Arkansas jurisdictional kWh at generation will be divided by the total kWh at generation for all jurisdictions to develop the Arkansas jurisdictional allocation factor. The NCEF jurisdictional allocation factor is derived in the same manner except that Texas is excluded which will increase the Arkansas jurisdictional allocation factor to increase the Arkansas share of the NCEF SPP net revenues and PTCs, net of transfer costs.

(4) The Carrying Charge Rate shall be the Commission authorized interest rate on customer deposits.

(5) The Estimated Energy Costs for the Projected Energy Cost Period is equal to the energy costs for the Historical Energy Cost Period (the calendar year immediately preceding the filing year). Should there be unusual circumstances associated with any Projected Energy Cost or Projected Energy Cost Period either the Company or the Staff may propose use of a Projected Energy Cost (PEC variable) different from that defined by this formula.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-27.9 Sheet 9 of 9	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A (continued)

(6) The loss correction factors will be determined by dividing the sum of the metered kWh sales for the Arkansas jurisdiction by the sum of the sales at the generation level for the Arkansas jurisdiction. This ratio of sales to generation is known as the "composite loss factor" for the Arkansas jurisdiction. The LCF for each voltage level is determined by dividing the service voltage loss factor by the composite loss factor.

(7) The deferred consumable balance under APSC Docket No. U-14-080-U as of the (effective with the first billing cycle of January 2020) amortized over five years.

(8) $AR\ ADJ_j$ as described in the definition above is an adjustment to Arkansas jurisdictional share of SWEPCO's total fuel cost for month (j). The detailed description of the adjustment effective with the implementation of the SPP IM is provided in the Direct Testimony and Exhibits of Naim Hakimi APSC Docket No. 14-022-TF, Page 9, Line 8 through Page 12, Line 6 and Exhibit ANH-4. The adjustment removes the Turk plant fuel cost (including related NO_x and SO_2 emissions costs) and associated revenues from sale of the Turk plant output in the SPP market from the Energy Cost.

(9) The recovery of energy costs associated with long-term renewable energy resources must be approved by the Commission prior to the recovery of costs through Rider ECR.

(10) No charges for environmental chemical costs may be passed through the rider to customers unless the Commission has approved the prudence of the particular environmental controls project at issue or the Commission has otherwise approved the recovery of the costs for such a project in retail rates.

COST OF FUEL ADJUSTMENT

COST OF FUEL ADJUSTMENT
A cost of fuel adjustment is applicable to the following rate schedules listed below. The current cost of fuel adjustment is a charge of $0.00000 per kWh. The cost of fuel adjustment is not applicable to energy priced under the RTP rider or to above the baseline usage subject to real time market pricing. **R**

Rate Schedule
Rg1, Rg2, Fg1
Cg1, Cg2, Cg3, Cg3C, Cg3S, Cg6, TssM, TssU
Cp1, Cp3, Cp3S, Cp4, CpFN
St1, St2, AL1, GL1, LED, Ms1, Ms2, Ms3, Ms4

CGS2, CGS6 and CGS8 (when a seller to or net purchaser from the Company)*
CGS-NP, CGS-NM (when a net purchaser from the Company)*
* Cost of fuel adjustment for these schedules is the cost of fuel adjustment corresponding to the underlying rate schedule.

COEV-R rate schedule usage is subject to a cost of fuel adjustment consistent with the applicable rate schedule under which the customer is served for their non-electric vehicle electricity usage.

WHEV-R and EV-C rate schedule usage is subject to a cost of fuel adjustment consistent with the applicable rate schedule under which the customer is served for their electric vehicle electricity usage.

ERER 1, ERER 3, ERER 4		
100% Renewable power	No adjustment for cost of fuel	
50% Renewable power	Cost of fuel adjustment factor applicable to customer's rate schedule applied to 50% of the kWh for the billing period.	**R**
25% Renewable power	Cost of fuel adjustment factor applicable to customer's rate schedule applied to 75% of the kWh for the billing period.	**R**
ERER 2		
kilowatt-hour in excess of nominated block	Cost of fuel adjustment factor applicable to customer's rate schedule.	**R**

The cost of fuel adjustment is $0.00 per kWh for the TE1, TE2 and Mg1 rate schedules.

WISCONSIN ELECTRIC POWER COMPANY
Volume 19 – Electric Rates | Revision 14 Sheet 20
Effective In All Areas Served In Wisconsin | Amendment No. 802

COST OF FUEL ADJUSTMENT – RECONCILIATION

This is an additional adjustment for cost of fuel for the refund of the 2022 fuel cost over-collection to be applied to service rendered September 1, 2024 to September 30, 2024. The cost of fuel adjustment refund is not applicable to energy priced under the RTP rider or to above the baseline usage subject to real time market pricing. **R** **R**

Rate Schedule	Volumetric Rate per kWh	R
Rg1, Rg2, Fg1	($0.00002)	R
Cg1, Cg2, Cg3, Cg3C, Cg3S, Cg6, TssM, TssU	($0.00002)	R
Cp1, Cp3, Cp3S, Cp4, CpFN	($0.00002)	R
St1, St2, AL1, GL1, LED, Ms1, Ms2, Ms3, Ms4	($0.00002)	R

CGS2, CGS6 and CGS8 (when a seller to or net purchaser from the Company)*
CGS-NP, CGS-NM (when a net purchaser from the Company)*
* Cost of fuel adjustment for these schedules is the cost of fuel adjustment corresponding to the underlying rate schedule.

COEV-R rate schedule usage is subject to a cost of fuel adjustment consistent with the applicable rate schedule under which the customer is served for their non-electric vehicle electricity usage.

WHEV-R and EV-C rate schedule usage is subject to a cost of fuel adjustment consistent with the applicable rate schedule under which the customer is served for their electric vehicle electricity usage.

ERER 1, ERER 3, ERER 4

100% Renewable power	No adjustment for cost of fuel
50% Renewable power	Cost of fuel adjustment factor applicable to customer's rate schedule applied to 50% of the kWh for the billing period.
25% Renewable power	Cost of fuel adjustment factor applicable to customer's rate schedule applied to 75% of the kWh for the billing period.

ERER

kilowatt-hour in excess of nominated block	Cost of fuel adjustment factor applicable to customer's rate schedule.

The cost of fuel adjustment is $0.00 per kWh for the TE1, TE2 and Mg1 rate schedules.

Respectfully submitted,

/s/ James P. Zakoura

James P. Zakoura, KS 07644
Lee M. Smithyman, KS 09391
Daniel J. Buller, KS 25002
Molly E. Morgan, KS 29683
FOULSTON SIEFKIN LLP
7500 College Boulevard, Suite 1400
Overland Park, KS 66210-4041
Telephone: 913-253-2142
Email: jzakoura@foulston.com
lsmithyman@foulston.com
dbuller@foulston.com
mmorgan@foulston.com

Attorneys for the Following:

Associated Purchasing Services
Cargill, Incorporated
CVR Refining CVL, LLC
Goodyear Tire & Rubber Company
Kansas Agribusiness Retailers Association
Kansas Biofuels Association
Kansas Grain and Feed Association
Lawrence Paper Company
Occidental Chemical Corporation
Spirit AeroSystems, Inc.

CERTIFICATE OF SERVICE

I hereby certify that on this 6th day of June 2025, the foregoing was electronically filed with the Kansas Corporation Commission and that one copy was delivered electronically to all parties on the service list as follows:

CATHRYN J. DINGES, SR DIRECTOR & REGULATORY AFFAIRS COUNSEL EVERGY KANSAS CENTRAL, INC 818 S KANSAS AVE PO BOX 889 TOPEKA, KS 66601-0889 cathy.dinges@evergy.com	LESLIE WINES SR. EXEC. ADMIN. ASST. EVERGY KANSAS CENTRAL, INC 818 S KANSAS AVE PO BOX 889 TOPEKA, KS 66601-0889 leslie.wines@evergy.com
COLE A BAILEY, CORPORATE COUNSEL DIRECTOR EVERGY KANSAS SOUTH, INC. D/B/A EVERGY KANSAS CENTRAL 818 S KANSAS AVE, PO Box 889 TOPEKA, KS 66601-0889 cole.bailey@evergy.com	DARRIN IVES, VP - REGULATORY AFFAIRS EVERGY METRO, INC D/B/A EVERGY KANSAS METRO One Kansas City Place 1200 Main St., 19th Floor Kansas City, MO 64105 darrin.ives@evergy.com
RONALD A. KLOTE, DIRECTOR, REGULATORY AFFAIRS EVERGY METRO, INC D/B/A EVERGY KANSAS METRO ONE KANSAS CITY PLACE 1200 MAIN, 19TH FLOOR KANSAS CITY, MO 64105 ronald.klote@evergy.com	BRIAN G. FEDOTIN, GENERAL COUNSEL KANSAS CORPORATION COMMISSION 1500 SW ARROWHEAD RD TOPEKA, KS 66604 brian.fedotin@ks.gov
PATRICK HURLEY, CHIEF LITIGATION COUNSEL KANSAS CORPORATION COMMISSION 1500 SW ARROWHEAD RD TOPEKA, KS 66604 patrick.hurley@ks.gov	CARLY MASENTHIN, LITIGATION COUNSEL KANSAS CORPORATION COMMISSION 1500 SW ARROWHEAD RD TOPEKA, KS 66604 carly.masenthin@ks.gov

VALERIE SMITH, ADMINISTRATIVE ASSISTANT MORRIS LAING EVANS BROCK & KENNEDY 800 SW JACKSON SUITE 1310 TOPEKA, KS 66612-1216 vsmith@morrislaing.com	TREVOR WOHLFORD, ATTORNEY MORRIS LAING EVANS BROCK & KENNEDY 800 SW JACKSON SUITE 1310 TOPEKA, KS 66612-1216 twohlford@morrislaing.com
GLENDA CAFER MORRIS LAING EVANS BROCK & KENNEDY CHTD 800 SW JACKSON STE 1310 TOPEKA, KS 66612-1216 gcafer@morrislaing.com	RITA LOWE, PARALEGAL MORRIS LAING EVANS BROCK & KENNEDY CHTD 300 N MEAD STE 200 WICHITA, KS 67202-2745 rlowe@morrislaing.com
WILL B. WOHLFORD, ATTORNEY MORRIS LAING EVANS BROCK & KENNEDY CHTD 300 N MEAD STE 200 WICHITA, KS 67202-2745 wwohlford@morrislaing.com	USD 259 903 SOUTH EDGEMOOR ROOM 113 WICHITA, KS 67218 (Sent via U.S. Mail)
JAMES G. FLAHERTY, ATTORNEY ANDERSON & BYRD, L.L.P. 216 S HICKORY PO BOX 17 OTTAWA, KS 66067-0017 jflaherty@andersonbyrd.com	ELIZABETH A. BAKER, ATTORNEY AT LAW BAKER, STOREY, & WATSON 1603 SW 37TH STREET TOPEKA, KS 66611 ebaker@bakerstorey.com
KURT J. BOEHM, ATTORNEY BOEHM, KURTZ & LOWRY 36 E SEVENTH ST STE 1510 CINCINNATI, OH 45202 kboehm@bkllawfirm.com	JODY KYLER COHN, ATTORNEY BOEHM, KURTZ & LOWRY 36 E SEVENTH ST STE 1510 CINCINNATI, OH 45202 jkylercohn@bkllawfirm.com
JOSEPH R. ASTRAB, CONSUMER COUNSEL CITIZENS' UTILITY RATEPAYER BOARD 1500 SW ARROWHEAD RD TOPEKA, KS 66604 joseph.astrab@ks.gov	TODD E. LOVE, ATTORNEY CITIZENS' UTILITY RATEPAYER BOARD 1500 SW ARROWHEAD RD TOPEKA, KS 66604 todd.love@ks.gov

SHONDA RABB CITIZENS' UTILITY RATEPAYER BOARD 1500 SW ARROWHEAD RD TOPEKA, KS 66604 shonda.rabb@ks.gov	DELLA SMITH CITIZENS' UTILITY RATEPAYER BOARD 1500 SW ARROWHEAD RD TOPEKA, KS 66604 della.smith@ks.gov
MELISSA M. BUHRIG, EXEC. VICE PRESIDENT, GEN. COUNSEL & SECRETARY CVR REFINING CVL, LLC 2277 Plaza Dr., Ste. 500 Sugar Land, TX 77479 mmbuhrig@CVREnergy.com	JASON T GRAY, ATTORNEY DUNCAN & ALLEN 1730 RHODE ISLAND AVE. NW, STE 700 WASHINGTON, DC 20036 jtg@duncanallen.com
JUSTIN BIEBER ENERGY STRATEGIES, LLC PARKSIDE TOWERS 215 S STATE ST STE 200 SALT LAKE CITY, UT 84111 jbieber@energystrat.com	DAVID BANKS, CEM, CEP FLINT HILLS ENERGY CONSULTANT 117 S PARKRIDGE WICHITA, KS 67209 david@fheconsultants.net
CONSTANCE CHAN, SENIOR CATEGORY MANAGER - ELECTRICITY & BUSINESS TRAVEL HF SINCLAIR EL DORADO REFINING LLC 2323 VICTORY AVE. STE 1400 DALLA, TX 75219 constance.chan@hfsinclair.com	JON LINDSEY, CORPORATE COUNSEL HF SINCLAIR EL DORADO REFINING LLC 550 E. SOUTH TEMPLE SALT LAKE CITY, UT 84102 jon.lindsey@hfsinclair.com
ANNE E. CALLENBACH, ATTORNEY POLSINELLI PC 900 W 48TH PLACE STE 900 KANSAS CITY, MO 64112 acallenbach@polsinelli.com	FRANK A. CARO, ATTORNEY POLSINELLI PC 900 W 48TH PLACE STE 900 KANSAS CITY, MO 64112 fcaro@polsinelli.com
JARED R. JEVONS, ATTORNEY POLSINELLI PC 900 W 48TH PLACE STE 900 KANSAS CITY, MO 64112 jjevons@polsinelli.com	GREG WRIGHT PRIORITY POWER MGT. 12512 AUGUSTA DR KANSAS CITY, KS 66109 gwright@prioritypower.com

KACEY S MAYES, ATTORNEY TRIPLETT, WOOLF & GARRETSON, LLC 2959 N ROCK RD STE 300 WICHITA, KS 67226 ksmayes@twgfirm.com	TIMOTHY E. McKEE, ATTORNEY TRIPLETT, WOOLF & GARRETSON, LLC 2959 N ROCK RD STE 300 WICHITA, KS 67226 temckee@twgfirm.com
JOHN J. McNUTT, GENERAL ATTORNEY U.S. ARMY LEGAL SERVICES AGENCY REGULATORY LAW OFFICE 9275 GUNSTON RD., STE. 1300 FORT BELVOIR, VA 22060-5546 john.j.mcnutt.civ@army.mil	KEVIN K. LACHANCE CONTRACT LAW ATTORNEY UNITED STATES DEPARTMENT OF DEFENSE ADMIN & CIVIL LAW DIVISION OFFICE OF STAFF JUDGE ADVOCATE FORT RILEY, KS 66442 kevin.k.lachance.civ@army.mil
NICK SMITH MANAGER OF KANSAS REGULATION BLACK HILLS ENERGY CORPORATION 601 NORTH IOWA STREET LAWRENCE, KS 66044 nick.smith@blackhillscorp.com	ROB DANIEL DIRECTOR OF REGULATORY BLACK HILLS/KANSAS GAS UTILITY COMPANY LLC D/B/A BLACK HILLS ENERGY 601 NORTH IOWA STREET LAWRENCE, KS 66044 rob.daniel@blackhillscorp.com
DOUGLAS LAW ASSOCIATE GENERAL COUNSEL BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY 1731 WINDHOEK DRIVE LINCOLN, NE 68512 douglas.law@blackhillscorp.com	LORNA EATON, MANAGER OF RATES AND REGULATORY AFFAIRS KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC. 7421 W 129TH STREET OVERLAND PARK, KS 66213 lorna.eaton@onegas.com
DANIEL J BULLER, ATTORNEY FOULSTON SIEFKIN LLP 7500 COLLEGE BOULEVARD, STE 1400 OVERLAND PARK, KS 66201-4041 dbuller@foulston.com	ROBERT E. VINCENT, MANAGING ATTORNEY KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC. 7421 W. 129TH STREET OVERLAND PARK, KS 66213 robert.vincent@onegas.com

MOLLY E MORGAN, ATTORNEY FOULSTON SIEFKIN LLP 1551 N. WATERFRONT PARKWAY SUITE 100 WICHITA, KS 67206 mmorgan@foulston.com	LEE M SMITHYMAN, ATTORNEY FOULSTON SIEFKIN LLP 7500 COLLEGE BOULEVARD, STE 1400 OVERLAND PARK, KS 66201-4041 lsmithyman@foulston.com
JAMES P ZAKOURA, ATTORNEY FOULSTON SIEFKIN LLP 7500 COLLEGE BOULEVARD, STE 1400 OVERLAND PARK, KS 66201-4041 jzakoura@foulston.com	TIM OPITZ OPITZ LAW FIRM, LLC 308 E. HIGH STREET SUITE B101 JEFFERSON CITY, MO 65101 tim.opitz@opitzlawfirm.com

/s/ James P. Zakoura

James P. Zakoura, #07644