Exhibit No.:	
Issue:	Energy Price Forecasting; Fuel, Purchased Power and Off-System Sales Normalization; FAC Requirements
Witness:	Hsin Foo
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Evergy Missouri Metro
Case No.:	ER-2026-0143
Date Testimony Prepared:	August 11, 2026

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2026-0143

REBUTTAL TESTIMONY

OF

HSIN FOO

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
August 2026

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

HSIN FOO

Case No. ER-2026-0143

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Hsin Foo. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Evergy Metro, Inc. as Lead Quantitative Analyst-Generation Resources.

Q: Are you the same Hsin Foo who filed direct testimony in this proceeding?

A: Yes. I filed direct testimony on behalf of Evergy Metro, Inc. d/b/a Evergy Missouri Metro (“Evergy Missouri Metro,” “EMM,” or the “Company”) on February 6, 2026.

Q: Who are you testifying for?

A: I am testifying on behalf of Evergy Missouri Metro.

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond to certain recommendations of the Staff of the Missouri Public Service Commission (“Staff”) and the Office of the Public Counsel (“OPC”). Specifically, I will address the following:

- natural gas prices developed by Staff witness Nieto that were used in Staff’s production cost model;
- market prices developed by Staff witness Tevie that were used in Staff’s production cost model;

- coal, oil and nuclear prices used in Staff's production cost model;
- Staff's exclusion of large load customers from Net System Input ("NSI") and the resulting impact on Staff's revenue requirement;
- the resulting generation at Wolf Creek Station produced from Staff's production cost model;
- the resulting coal generation produced from Staff's production cost model;
- the inclusion of Greenwood Solar Facility in Staff's production cost model;
- fixed fuel costs and fuel adder expenses included in Staff's revenue requirement;
- Staff's level of revenues and expenses associated with border customers;
- Staff's treatment of Transmission Congestion Rights ("TCR") margin;
- the level of Revenue Neutrality Uplift ("RNU") charges in Staff witness Nieto's adjustments;
- the level of Ancillary Service charges and Missouri Iowa Nebraska Transmission ("MINT") line losses;
- Staff's Option 2 for Large Load Customers in the FAC;
- and the heat rate testing filing requirement under 20 CSR 4240-20.090(2)(A)15.

II. NATURAL GAS PRICES AND MARKET PRICES

Q: What are market prices and how do they impact variable fuel and purchase power expense?

A: Market prices, also known as Locational Marginal Prices ("LMPs"), is the cost of supplying the next unit of electricity to a specific location on a transmission network. It is the market clearing price at which energy is bought and sold at each node, or Settlement

Location ("SL"). In simplified terms, a generator sells power and receives revenues determined by the LMP at a generator SL. Electricity, whose cost is determined by the LMP at the load SL, is then purchased to serve the required load.

Q: What are the main drivers of market prices that affect the Company?

A: In Southwest Power Pool ("SPP"), the regional transmission organization in which the Company is located, market prices during periods of high demand are frequently determined by natural gas-fired resources operating on the margin. Because the variable production costs of these resources are largely driven by natural gas prices, changes in natural gas prices directly affect market prices in SPP, which in turn affects both the Company's purchased power costs and its market-based revenues. During periods when the Company's available generating resources are insufficient to serve its load requirements, the Company purchases energy from the SPP market at prevailing LMPs. Conversely, when the Company has generation in excess of its load requirements, it may sell that excess energy to the SPP market with the resulting revenues likewise determined by prevailing LMPs. Accordingly, changes in natural gas prices can significantly influence both the Company's fuel and purchased power expense, and the revenues it earns from off-system sales. Because LMPs affect both sides of this equation, it is important that production cost modeling use representative and internally consistent market assumptions so that both purchased power costs and market revenues reasonably reflect expected operating conditions.

Q: What market prices does Staff use in its production cost model?

A: Staff witness Tevie developed hourly market prices using raw SPP marketplace data for the two years ending December 2025.[1] He excluded two abnormal events—the January 13-17, 2024, cold snap and the February 19-20, 2025, late-winter event—and constructed normalized prices through a seven-step process that sorts hourly data by season, computes and ranks seasonal averages, and matches 2025 seasonal ranks to select an hourly price for each pricing node.[2]

Q: What natural gas price input does Staff use?

A: Staff witness Nieto used the actual monthly commodity cost of natural gas for the two-year period ending December 31, 2025, but excluded natural gas prices for the period of January 13-17, 2024. She reasoned that the brief price spike during that period was driven by extraordinary market conditions and that its inclusion would skew the historical average upward.[3] She further explained that both she and Mr. Tevie adjusted for the January 2024 abnormality, but that she did not adjust for the February 2025 price spike because it had a negligible impact on the natural gas price calculation.[4]

Q: Does the Company agree with Staff's treatment of the natural gas price input?

A: No, the Company disagrees with Staff's approach because it does not produce a representative estimate of the natural gas prices the Company can reasonably expect to face during the period in which new rates will be in effect. Staff's methodology uses a monthly weighted average of natural gas prices from 2024 and 2025. However, natural gas prices during 2024 were unusually low relative to prevailing market conditions over the past

[1] See J. Tevie (Staff) Direct at 2-3.
[2] Id. at 3-4.
[3] See A. Nieto (Staff) Direct at 23.
[4] Id. at 23-24.

decade. Schedule HYF-7 presents the average annual natural gas spot price from January 2015 through June 2026 at Henry Hub, a major natural gas pricing hub that is considered the United States' benchmark for natural gas prices. As shown in Schedule HYF-7, the average price in 2024 was among the lowest observed during this period and was higher only than the average price in 2020.[5] The depressed prices in 2024 were driven by an unusual market oversupply caused by record domestic natural gas production, high storage inventories, and two consecutive mild winters that reduced natural gas demand. This can also be seen in Schedule HYF-8, which presents the average monthly Henry Hub spot price from January 2021 to June 2026. In 2024, the monthly average price was the lowest in 10 of the 12 calendar months shown. The data demonstrates that the low natural gas prices observed during 2024 were not isolated to a few months but persisted throughout most of the year. Consequently, a methodology that relies exclusively on 2024 and 2025 historical prices places disproportionate weight on a period characterized by extraordinary oversupply and is not supported by current market fundamentals.

Q: How do Staff's natural gas price assumptions affect their production cost model?

By incorporating these lower natural gas prices into its production cost model, Staff understates the fuel costs of natural gas-fired generating resources that frequently establish LMPs in the SPP market. This affects not only the Company's modeled fuel expense, but also the market prices that influence both Staff's modeled purchase power costs and the revenues from off-system sales. Schedule HYF-9 presents the average monthly day-ahead LMP at the Company's load SL which represents that market price at which the Company purchases energy. Similar to the natural gas price data discussed previously, the 2024 day-

[5] Natural gas prices declined to historically low levels in 2020 because the COVID-19 pandemic significantly reduced domestic and global natural gas demand.

ahead LMPs were among the lowest observed during the period presented, with the exception of January, when Winter Storm Heather temporarily impacted prices. While Staff applies a normalization technique to reduce the influence of low market prices, the effect is not fully eliminated. Because natural gas prices and LMPs are closely linked in SPP, assumptions that rely on an atypically low-price environment will influence the model's economic dispatch. As a result, Staff's selection of natural gas price and market price assumptions extend throughout the production cost model, affecting dispatch decisions, market purchases, market sales, and the resulting estimate of normalized fuel and purchased power expense.

Q: How does the Company develop the natural gas prices used in its production cost model?

A: As described in Company witness Jessica Tucker's direct testimony, Evergy Missouri Metro uses a 3-year average of natural gas futures settlement prices on September 10, 2025, for the period of January 2025 through December 2027.[6] Forward natural gas prices represent the market's current expectation of future natural gas prices and incorporates all currently available information affecting expected future supply and demand, including production levels, storage inventories, transportation constraints, and other market fundamentals. Rather than reproducing historical market conditions, an average of actual prices and forward prices are more consistent with the objective of normalization and provide a reasonable estimate of prices expected during the period when new rates will be in effect.

[6] See J. Tucker Direct at 5.

Q: How does the Company develop the market prices used in its production cost model?

A: As I described in my direct testimony, Evergy Missouri Metro uses PROMOD, a fundamental price forecasting model provided by Hitachi Energy that is widely used in the industry.[7] PROMOD performs a security-constrained unit commitment and co-optimized economic dispatch to generate LMPs at the nodal level, in a manner comparable to how SPP and other Regional Transmission Organizations ("RTO") set schedules and determine prices. For each hour, the model solves for the cost of generation from the least-cost unit needed to meet demand to compute the hourly LMP.

Q: What is the difference between the Company's and Staff's approach to market prices?

A: Staff's model largely relies on the reasonableness of its market price inputs. If those market prices are not representative of expected future conditions, or if they are not economically consistent with the model's fuel price assumptions, the resulting estimates of purchased power costs and market revenues may not accurately reflect expected system operations. The Company's PROMOD market prices are calculated as part of the simulation itself. PROMOD economically dispatches generating resources across the regional system based on unit operating characteristics, fuel prices, load, and other operating assumptions. The resulting market prices are therefore an output of the simulation rather than an independent model input. This approach preserves the economic relationships between the production costs of natural gas-fired generating units and market prices, causing changes in natural gas prices to be reflected in both generation dispatch decisions and the resulting simulated LMPs.

[7] See H. Foo Direct at 3-4.

Q: Should the Commission reject Staff's natural gas price and market price assumptions?

A: Yes. The Commission should reject Staff's natural gas price and corresponding market price assumptions because they rely on historically low prices that do not reasonably reflect the market conditions expected during the period new rates will be in effect. These assumptions affect unit dispatch, purchased power costs, off-system sales revenues, and ultimately normalized fuel and purchased power expense. Accordingly, the Commission should adopt assumptions that more reasonably reflect expected market conditions.

III. COAL, OIL, AND NUCLEAR PRICES

Q: How did Staff determine the coal prices used in their production cost model?

A: Staff witness Nieto states that Staff based its recommended coal price on the Company's actual delivered coal costs for the 12-months ending December 31, 2025, and will review the Company's coal supply and transportation contracts effective as of June 30, 2026, to reflect any changes at True-Up.[8] The Company agrees that coal prices should be updated at the end of the true-up period to reflect the most current contract terms and delivered coal costs available.

Q: How did Staff determine the oil prices used in their production cost model?

A: Staff witness Nieto states that Staff reviewed the Company's oil contracts for the 12-months ending December 31, 2025, and recommended a price of **[redacted]** per MMBtu.[9]

CONFIDENTIAL

[8] See A. Nieto (Staff) Direct at 22-23.
[9] Id. at 25.

Q: Does the Company agree with Staff's oil price recommendation?

A: The Company expects Staff to true up its recommended oil prices at the end of the true-up period to reflect the most current contract terms and pricing available as of June 30, 2026. If Staff completes this work at true-up, we anticipate agreement.

Q: How did Staff determine the nuclear prices used in their production cost model?

A: Staff witness Nieto states that Staff's recommended nuclear price is based on the average actual costs incurred during the 12-months ending December 31, 2025.[10]

Q: Does the Company agree with Staff's nuclear price recommendation?

A: The Company expects Staff to true up its recommended nuclear prices at the end of the true-up period to reflect the most current pricing available as of June 30, 2026. If Staff completes this work at true-up, we anticipate agreement.

IV. LARGE LOAD CUSTOMERS IN NET SYSTEM INPUT

Q: Who are the Company's large load customers?

A: The Company currently serves one large load customer, Customer A. As discussed by Company witness Graham A. Jaynes, Customer B is a Large Power Service customer with notable growth that Staff has incorporated into their "LLPS true-up plug." Because both customers are relevant to the issues addressed in this section, they are referred to collectively as the "Large Load Customers." This terminology is used for ease of reference and does not reflect Company agreement with any underlying assumption regarding customer classification or grouping.

[10] See A. Nieto (Staff) Direct at 24.

Q: How does Staff witness Lange address Large Load Customers in Staff's revenue requirement?

A: Staff witness Lange addresses the treatment of the Large Load Customers' increasing load in Staff's NSI, production cost modeling and true-up plug. For Customer A, Staff recognizes its annualized true-up load and associated revenues but does not include that load in NSI or the production cost model. For Customer B, Staff includes its annualized load as of the update period in NSI but excludes the incremental load through True-Up. Staff address the excluded load and certain associated costs separately through its true-up plug.[11]

Q: Why does Staff exclude the Large Load Customers from its production cost model?

A: Staff witness Lange states that Staff does not have sufficient detailed information regarding the timing and magnitude of the Large Load Customers' usage to incorporate the incremental load into NSI. Staff therefore concludes that it lacks a reasonable basis to develop the detailed load profiles necessary for production cost modeling and instead addresses the load through its true-up plug.[12]

Q: Do you agree that the lack of a complete historical load profile justifies excluding the incremental load from the production cost model?

A: No. I recognize that the Large Load Customers are ramping and that a complete historical hourly load profile may not yet be available. However, the absence of complete historical data does not mean that a significant and known increase in native load should be excluded from the production cost model altogether. Staff's approach effectively assumes that

[11] See S. Lange (Staff) Direct at 22-24.
[12] Id. at 24-26.

because the precise hourly shape of the incremental load is uncertain, the appropriate amount to include in the production cost model is zero.

Q: Why is it important to include Large Load Customers in the production cost model?

A: A production cost model evaluates the Company's generation and market activity in an integrated manner. The addition of significant native load can change how the Company's entire generation portfolio is dispatched, and impact market purchases, off-system sales, and the Company's overall position in the SPP market. These effects cannot be captured by simply adding an incremental cost after the production cost model has already determined its dispatch.

Q: Does Staff's true-up plug adequately capture these impacts?

A: No. Staff's true-up plug does not capture the full economic impact of serving Large Load Customers because they are excluded from the production cost model. Staff separately estimates incremental revenues and certain incremental costs associated with Large Load Customers, but that calculation does not account for how the additional load affects unit commitment, dispatch, market purchases, off-system sales, and how the Company's generation portfolio interacts with the SPP market. This creates a mismatch in Staff's normalization and results in an incomplete representation of the net-system cost associated with Large Load Customers.

Q: What does the Company recommend?

A: A normalized load for Large Load Customers should be incorporated into NSI using the best information available at True-Up. While complete historical hourly load data may not yet be available, that does not justify excluding known and measurable load from the production model. Including a normalized load for Large Load Customers in NSI allows the production cost model to evaluate the corresponding integrated changes in generation, fuel expense, market purchases, off-system sales revenues, and overall net system costs. This approach provides a more complete and consistent normalization than Staff's true-up plug because it recognizes both the additional load and resulting costs and market impacts of serving that load within the same modeling framework.

V. <u>WOLF CREEK MODELING</u>

Q: What is the Wolf Creek Generating Station?

A: Wolf Creek Generating Station ("Wolf Creek") is a 1,200 MW nuclear generating station located in Coffey County, Kansas. The Company has a forty-seven (47%) percent ownership share of Wolf Creek.

Q: How does Wolf Creek typically operate in the SPP market?

A: Wolf Creek is a baseload nuclear generating station that is designed and operated to produce electricity at or near full output on a continuous basis. Unlike other types of fossil-fueled generating units, Wolf Creek is not routinely dispatched to follow short-term fluctuations in market prices or system load. Instead, it typically operates at or near its maximum available output except during planned refueling outages or other operational limitations. **CONFIDENTIAL** Schedule HYF-10 presents Wolf Creek's historical hourly generation since January 2024 and demonstrates its consistent operating profile.

Q: How does the modeled generation from Staff's production model compare to Wolf Creek's actual operating characteristics?

A: **CONFIDENTIAL** Schedule HYF-11 shows Wolf Creek's modeled generation in Staff's production cost model. Unlike the historical operating profile shown in **CONFIDENTIAL** Schedule HYF-10, Staff's model dispatches Wolf Creek as though it regularly increases and decreases output in response to changing market conditions. This does not reasonably reflect how Wolf Creek operates.

Q: How does Staff's modeling of Wolf Creek affect the dispatch of other generating units and the overall results of the production cost model?

A: Because Wolf Creek serves as a baseload generating resource, modeling it as a unit that easily changes its output distorts the generation that must be supplied by the remainder of the Company's fleet. If the model allows Wolf Creek to reduce output when the station would normally remain at or near full output, the model must replace that energy with generation from other units or market purchases. Conversely, when Wolf Creek is modeled to increase output from an artificially reduced level, the model may displace generation from other Company units or reduce market purchases. As a result, these artificial changes in the dispatch of Wolf Creek can alter which other fossil fuel units are committed and dispatched, their fuel consumption, the amount and timing of market purchases and off-system sales, and the resulting production costs. An unrealistic operating profile for a large baseload resource such as wolf Creek can affect more than Wolf Creek's modeled generation; it will distort the model's overall dispatch and the resulting estimate of normalized fuel and purchased power costs.

VI. COAL FLEET MODELING

Q: Do you agree with Mr. Niemeier's modeling results of the Company's coal generating units?

A: No, I do not. Staff's production cost model dispatches the coal-fired generating units significantly less than they have been dispatched in recent years. As shown in **CONFIDENTIAL** Table HYF-1, Staff's model projects total coal generation from the Company's coal fleet of approximately 8.3 million MWh, compared to an average of approximately 10.0 million MWh over the 2021 through 2025 period. This represents a reduction of approximately 16 percent from the Company's recent coal generation activity. In addition, every coal-fired generating unit in Staff's model is dispatched below its five-year average.

<u>Table HYF-1: Annual Generation (MWh) from Coal-Fired Generating Units vs Coal Generation from Staff's Production Cost Model</u>**

[redacted]

**

Q: What does this indicate?

A: It indicates that Staff's production cost model does not reasonably represent the expected operation of the Company's coal-fired generating fleet. Staff's results show a systematic reduction in coal generation across the entire fleet rather than isolated differences at individual generating units.

Q: Why is this important to the Commission's determination of normalized fuel and purchased power costs?

A: As Staff's production cost model consistently dispatches the Company's coal-fired generating units at levels that are materially below recent operating behavior, it raises questions about whether the model's underlying assumptions reasonably reflect normalized operating conditions. If the model consistently under-dispatches the Company's coal-fired generating units because it relies on unrepresentative natural gas prices, unrepresentative market prices, or other unrealistic assumptions, it will not reasonably estimate how the Company is expected to operate during the period rates will be in effect.

VII. GREENWOOD SOLAR FACILITY

Q: What is the Greenwood Solar Facility?

A: Greenwood Solar Facility ("Greenwood Solar") is a solar-powered facility located in Greenwood, Missouri.

Q: Should Greenwood Solar be included in Staff's fuel and purchase power expense calculation?

A: No, Greenwood Solar belongs to Evergy Missouri West and should not be included in the Company's generation mix. See the testimony of Company witness Darrin Ives who addresses this issue.

VIII. FIXED FUEL COSTS AND OTHER NON-MODELED FUEL EXPENSES

Q: How did Staff account for fixed fuel costs and other non-modeled fuel expenses?

A: Staff witness Nieto states that Staff included annualized amounts of fixed fuel costs based on the actual costs during the 12-months ending December 31, 2025.[13]

Q: Does the Company agree with Staff's recommendations for fixed fuel costs and other non-modeled fuel expenses?

A: The Company expects Staff to true up its recommended fixed fuel costs and other non-modeled fuel expenses at the end of the true-up period to reflect the most recent costs and expenses available as of June 30, 2026. If Staff completes this work at true-up, we anticipate agreement.

[13] See A. Nieto (Staff) Direct at 25.

IX. BORDER CUSTOMERS

Q: How did Staff account for revenues and expenses associated with border customers?

A: Staff witness Nieto states that Staff included annualized border customer revenues and expenses based on the actual costs during the 12-months ending December 31, 2025.[14]

Q: Does the Company agree with Staff's recommendations for revenues and expenses associated with border customers?

A: The Company expects Staff to true up its recommended border customer revenues and expenses at the end of the true-up period to reflect the most recent amounts available as of June 30, 2026. If Staff completes this work at true-up, we anticipate agreement.

X. TRANSMISSION CONGESTION RIGHTS

Q: What are TCRs?

A: TCRs are financial instruments that allow SPP market participants to hedge the cost of transmission congestion in the SPP market. TCRs provide revenues or charges based on differences in congestion prices between specified locations on the transmission system, helping offset congestion costs incurred in the energy market. For a simplified example, assume a generator injects 1 MWh of energy at Generator Settlement Location ("Generator SL") and a load withdraws that same 1 MWh at Load Settlement Location ("Load SL") during a particular hour. If the LMP at the Generator SL is $10/MWh and the LMP at the Load SL is $12/MWh, SPP pays the generator $10 for the energy injected, while the load pays $12 for the energy withdrawn. The $2/MWh difference represents the transmission congestion cost between the two settlement locations and is reflected directly in the market settlement. A market participant holding a TCR of 1 MW for the path from the Generator

---

[14] See A. Nieto (Staff) Direct at 6.

SL to the Load SL would then receive $2, offsetting that same congestion cost. The value of a TCR is directly tied to the congestion costs reflected in the energy market. Congestion costs are embedded in the LMPs used to settle energy purchases and sales, and TCR revenues represent the corresponding financial hedge for those congestion costs.

Q: How did Staff determine the level of TCR margin included in its revenue requirement?

A: Staff normalized fuel and purchased power costs using its production cost model. However, rather than normalizing TCR margin using the same market conditions reflected in that model, Staff included a TCR margin based on a three-year historical average[15].

Q: Do you agree with Staff's approach?

A: No. In my opinion, Staff's methodology is inconsistent because it combines two different methods for estimating market-based revenues and expenses. The purpose of Staff's production cost model is to estimate normalized fuel and purchased power costs under a representative set of market conditions. Those same market conditions also influence the value of the Company's TCR portfolio. TCR revenues and their associated congestion costs are driven by transmission congestion patterns and locational price differences across the Company's service territory. Those conditions are directly related to the same dispatch decisions, transmission flows, and market prices that Staff uses in their model.

Q: Why is that a concern?

A: TCR margin is directly linked to congestion patterns and market prices and should be evaluated using assumptions that are consistent with those used to determine normalized fuel and purchased power costs. Mixing modeled market conditions with historical

[15] See A. Nieto (Staff) Direct at 16.

averages reduces the internal consistency of the overall revenue requirement and may over- or understate the Company's expected net fuel and purchased power costs.

Q: Do you have additional concerns with Staff's treatment of TCR margin?

A: Yes. In addition to using a historical average that is inconsistent with Staff's production cost model, Staff's methodology also results in congestion costs being reflected twice.

Q: Please explain.

A: Staff's production cost model uses LMPs as an input into their model to calculate normalized fuel and purchase power costs. By definition, LMPs include the cost of transmission congestion. Staff's modeled purchased power costs already reflect the congestion costs associated with serving load under the market conditions simulated by the model. Staff then separately includes an adjustment using historical TCR margin. TCR margin consists of TCR revenues, congestion costs and other costs associated with participating in the TCR market. Separately including a historical TCR margin after congestion has already been incorporated into the modeled purchase power costs results in the economic effects of congestion being reflected twice.

Q: How does the Company account for TCRs?

A: The Company analyzed actual TCR margin and actual congestion costs for the three-year period ending August 2025 to develop an average recovery factor representing the portion of congestion costs historically offset by TCR revenues. The Company then applied that recovery factor to the normalized congestion costs produced by the Company's production cost model to estimate normalized TCR revenues. Because the same production cost model was used to determine fuel costs, purchased power costs and off-system sales revenues, the TCR revenues are based on the same modeled market conditions.

Q: Why is this approach preferable to Staff's method?

A: The Company is not using historical TCR revenues to estimate future TCR revenues. Instead, the Company uses historical data only to establish the relationship between congestion costs and TCR revenues through the recovery factor. By applying that recovery factor to the normalized congestion costs produced by the Company's production cost model, the Company's method preserves the economic relationship between congestion costs and TCR revenues while maintaining internal consistency through the normalization process. In contrast, Staff normalizes fuel and purchased power costs using the production cost model under a representative market condition but relies on a historical three-year average of TCR margin that was earned under different congestion patterns and market conditions. The Company's approach avoids this inconsistency by ensuring that both congestion costs and the corresponding TCR revenues are based on the same normalized market assumptions.

Q: What do you recommend the Commission regarding Staff's treatment of TCRs?

A: The Company recommends that the Commission reject Staff's TCR flawed methodology and adopt the Company's approach because it avoids double counting congestion costs and maintains consistency between normalized congestion costs and the corresponding TCR revenues.

XI. <u>REVENUE NEUTRALITY UPLIFT CHARGES</u>

Q: What are RNU charges?

A: SPP RNU charges are market settlement adjustments that allocate certain market-wide charges and credits among market participants to ensure that SPP remains revenue neutral. Depending on market conditions, RNU may result in either a charge or credit.

Q: What levels of RNU did Staff include?

A: Staff witness Nieto states that Staff normalized RNU charges based on the three-year average ending December 31, 2025.[16] However, my review of Staff's workpaper indicates that Staff instead used the actual 12-month RNU charges ending December 31, 2025, which is the amount reflected in Staff's Accounting Schedule 10.[17] The RNU charges included in Staff's revenue requirement do not appear to reflect the three-year average described in Ms. Nieto's testimony.

Q: Will the level of RNU charges be updated at True-Up?

A: Staff witness Nieto states that Staff may update its recommendation to reflect the actual 12-months of RNU charges ending June 30, 2026. The Company agrees with this approach and expects the level of RNU charges to be updated to reflect the actual 12-month period ending June 30, 2026, at true-up. If Staff completes this work at true-up, we anticipate agreement.

XII. ANCILLARY SERVICES AND MINT LINE LOSSES

Q: What levels of Ancillary Service charges did Staff include?

A: Staff witness Nieto states that Staff used a three-year average based on actual charges from 2023 to 2025 and may update its recommendation to using actual charges from a 12-month period ending June 30, 2026, at True-Up.[18]

---

[16] See A. Nieto (Staff) Direct at 17.

[17] See A. Nieto (Staff) Workpaper "Confidential-Metro - ER-2026-0143-TCR-Ancillary Services-RNU-RTO-Nieto-Direct.xlsx".

[18] Id. at 18.

Q: Does the Company agree with Staff's recommendations for Ancillary Service charges?

A: The Company expects Staff to true up its Ancillary Service charges at the end of the true-up period to reflect the most recent amounts available as of June 30, 2026.[19] If Staff completes this work at true-up, we anticipate agreement.

Q: What levels of MINT line losses did Staff include?

A: Staff witness Nieto states that Staff used an annualized level based on actual expenses for the 12-month period ending December 31, 2025.

Q: Does the Company agree with Staff's recommendations for MINT line losses?

A: The Company expects Staff to true up its MINT line losses at the end of the true-up period to reflect the most recent amounts available as of June 30, 2026. If Staff completes this work at true-up, we anticipate agreement.

XIII. STAFF'S OPTION 2 FOR LARGE LOAD CUSTOMERS

Q: What is Staff's Option 2 regarding the treatment of Large Load Customers in the FAC?

A: Under Option 2, Staff proposes to remove Large Load power Service ("LLPS") customers from the FAC and exclude certain energy and transmission-related costs that Staff attributes to those customers. Staff would calculate day-ahead energy expense using LLPS customer's hourly load and the Company load-node LMP, while allocating other energy-based and demand-based SPP settlement charges using the Large Load Customer's share of Missouri jurisdictional kWh or kW[20].

---

[19] See A. Nieto (Staff) Direct at 17.
[20] See S. Lange (Staff) Direct at 47.

Q: Does the Company agree with Staff's Option 2?

A: No. Staff's methodology attempts to isolate the wholesale market costs associated with individual retail customers even though the Large Load Customers are served as part of the Company's integrated system. Their load affects generation dispatch, fuel consumption, market purchases and sales, congestion and other SPP market activity. Those effects cannot be reliably separated through a simple customer-specific allocation.

Q: What is your concern with Staff's allocation of SPP settlement costs?

A: Staff's allocation methodology does not establish cost causation. For certain SPP energy-based transactions, Staff proposes to assign costs based on the Large Load Customers' monthly kWh as a percentage of total Missouri jurisdictional kWh, and it proposes a similar approach for demand-based transactions using kW. A Large Load Customer representing a particular percentage of Missouri jurisdictional energy does not necessarily cause that same percentage of an SPP settlement charge. For example, a customer that represents 10% of jurisdictional energy does not necessarily cause 10% of a particular SPP charge. Staff's methodology therefore relies on an allocation assumption rather than the actual factors SPP uses to determine costs. That methodology is not a valid determination of the SPP costs attributable to Large Load Customers.

Q: Is Staff's treatment of day-ahead energy consistent with its treatment of other SPP settlement costs?

A: No. For day-ahead energy, Staff recognizes the importance of customer-specific hourly load and hourly LMPs. However, for other SPP transactions, Staff relies on broad monthly kWh or kW allocation factors. Those methodologies are fundamentally different. One attempts to identify an hourly cost associated with load, while the other simply allocates a portion of an aggregate SPP settlement amount.

Q: Why is that distinction important?

A: Because serving the Large Load Customers changes the Company's overall system and market position. The resulting wholesale costs and revenues vary by hour and depend on system and market conditions. A monthly allocation based solely on the Large Load Customers' percentage of jurisdictional energy or demand cannot fully capture those effects.

Q: What is the overall concern with Option 2?

A: Option 2 does not actually identify and remove the SPP costs caused by the Large Load Customers. Instead, it creates proxies for those costs and then removes the resulting allocated amounts from the FAC. Staff's proposal is also inconsistent with concerns Staff witness Lange raises regarding the use of generalized energy and demand information. Staff recognizes that the timing and coincidence of customer peaks matter for demand-related calculations[21]. Yet Option 2 attempts to allocate SPP costs using generalized customer energy and demand ratios that do not necessarily reflect the specific settlement determinants that caused those costs. It is difficult to reconcile Staff Lange's concerns with Option 2's assumption that aggregate monthly kWh and kW ratios provide a reasonable basis for assigning SPP settlement costs to Large Load Customers.

[21] See S. Lange (Staff) Direct at 26-27 and 47 n.13.

Q: What does the Company recommend?

A: The Company recommends that the Commission not adopt Staff's Option 2 because it does not provide a reasonable or reliable basis for assigning SPP settlement costs to Large Load Customers.

XIV. <u>RESPONSE TO OPC WITNESS MR. ROBINETT - HEAT RATE TESTING</u>

Q: Did Evergy Missouri Metro satisfy the Commission's heat rate testing filing requirement per 20 CSR 4240-20.090(2)(A)15?

A: Yes. OPC asserts that the Company has not satisfied all of the requirement's elements because **CONFIDENTIAL** Schedule HYF-5 (Direct) reports a single net heat rate for each generating unit without the underlying data, generated reports, or heat rate curves, and without the date of each test.[22] However, as I explained in my direct testimony, the Company provided heat rate test results conducted within the previous twenty-four months, and it provided the documentation of the actual monitoring procedures in **CONFIDENTIAL** Schedule HYF-6 (Direct).[23] **CONFIDENTIAL** Schedule HYF-5 (Direct) reports, for each applicable generating unit, the net heat rate together with the heat input curve coefficients used to derive the unit's heat rate across its load range. **CONFIDENTIAL** Schedule HYF-6 (Direct) is the Company's Heat Rate Testing Procedure, which describes the data collection, analysis, curve development, testing, and documentation process the Company follows and which is submitted to the Commission because the information is required for the FAC. The Company believes these schedules satisfy the filing requirement of 20 CSR 4240-20.090(2)(A)15.

[22] <u>See</u> J. Robinett (OPC) Direct at 3-5.
[23] <u>See</u> H. Foo Direct at 18.

Q: Why did the Company change from an annual single-load heat rate test to its current monitoring process?

A: The Company determined that using actual operating data to develop and routinely review heat rate curves provides a more representative measure of generating unit performance than an annual single-load heat rate test. A single-load test reflects unit performance under only one set of operating conditions, while the Company's current methodology evaluates a broader set of actual operating data across multiple load levels and operating conditions. This provides a more comprehensive assessment of unit performance, allows the Company to identify performance trends over time, and enables the Company to detect changes in efficiency that may warrant further investigation or corrective action.

Q: Does the Company's current methodology reduce the amount of information available to monitor generating unit performance?

A: No. The Company continues to collect data during its annual summer operational and capability test, and that data is used to validate the heat rate curves when necessary. No information has been lost as a result of the change in methodology. Instead, the Company now has a more comprehensive and representative process for monitoring generating unit efficiency than was available through an annual single-load heat rate test alone.

XV. CONCLUSION

Q: Please summarize your testimony.

A: My rebuttal testimony demonstrates that several of Staff's modeling assumptions do not reasonably reflect the market conditions that the Company expects to experience during the period new rates will be in effect. Specifically, I explain that Staff's reliance on historically low natural gas prices and corresponding market price assumptions understates their normalized fuel and purchased power costs and affects the estimated level of off-system sales revenues. I also explain why Staff's exclusion of the Large Load Customers' normalized load from NSI prevents its production cost model from fully capturing the effects of serving that load on generation dispatch, fuel consumption, market purchases, off-system sales revenues, and overall net system costs. The Company recommends incorporating a reasonable normalized level of Large Load Customer load into NSI using the best information available at True-Up, rather than attempting to account for those impacts through a separate true-up plug. I further explain why Staff's Option 2 should not be adopted. Staff's proposal does not provide a reasonable basis for identifying or assigning SPP settlement costs attributable to Large Load Customers. In addition, I explain that certain results produced by Staff's production cost model, including the modeled operation of Wolf Creek and the dispatch of the Company's coal-fired generating units, are not representative of their historical operating characteristics. I also explain why Staff's treatment of TCRs is inconsistent with its production cost modeling and does not produce a normalized estimate of TCR revenues that is based on the same market conditions reflected in their production cost model. For several other issues, the Company generally agrees that the recommended levels should be updated at True-Up using the most current information available. Finally, I explain why the Company's heat rate monitoring process satisfies the Commission's filing requirements. For these reasons, I recommend that the Commission adopt the Company's recommendations, which provide a more representative and internally consistent level of normalized fuel costs, purchased power costs and off-system sales revenues for inclusion in the Company's revenue requirement.

Q: Does this conclude your rebuttal testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2026-0143

AFFIDAVIT OF HSIN FOO

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Hsin Foo, being first duly sworn on his oath, states:

1. My name is Hsin Foo. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Lead Quantitative Analyst-Generation Resources.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Evergy Missouri Metro consisting of twenty-six (26) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

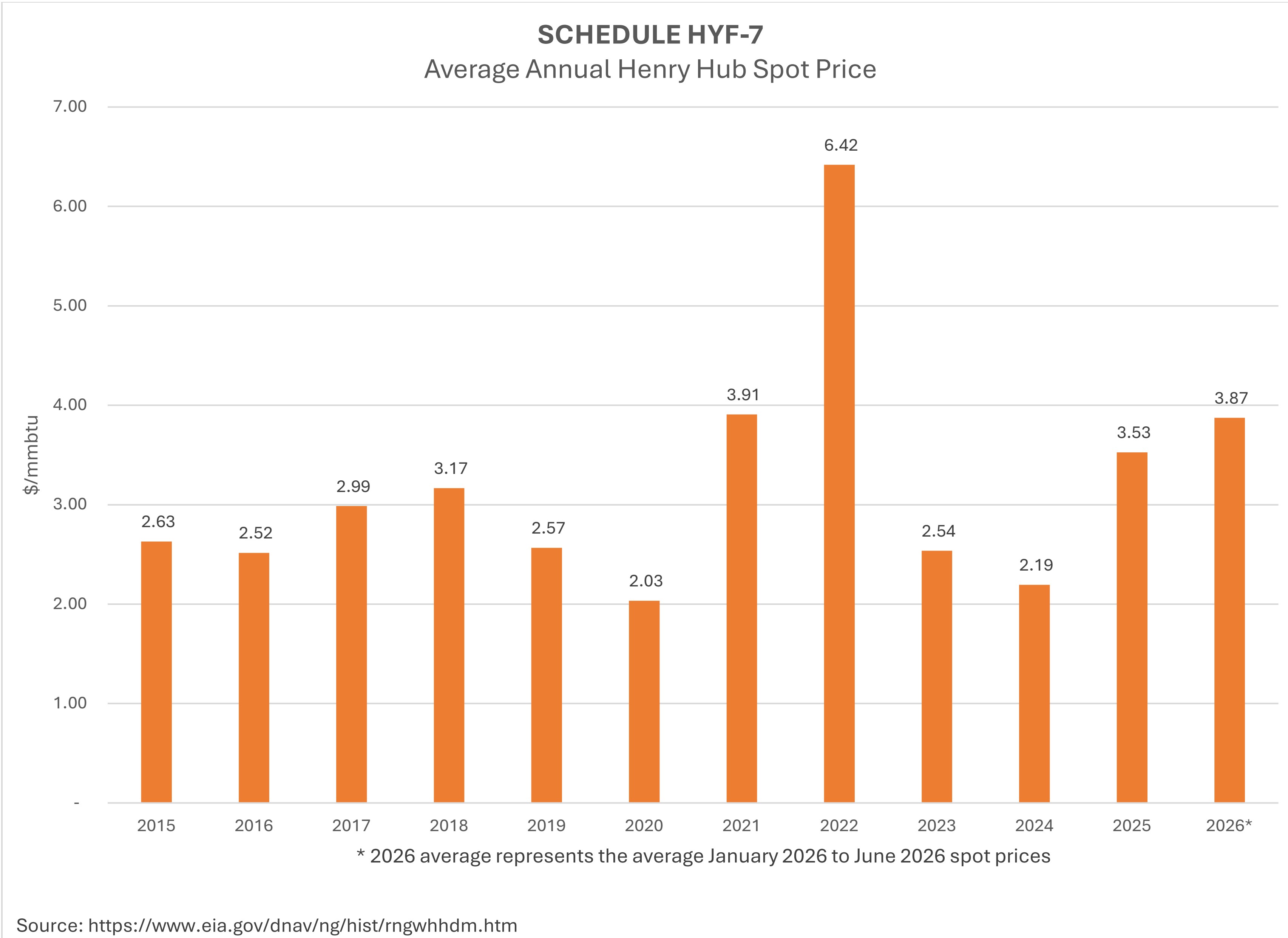
Hsin Foo

Subscribed and sworn before me this 11th day of August 2026.

Notary Public

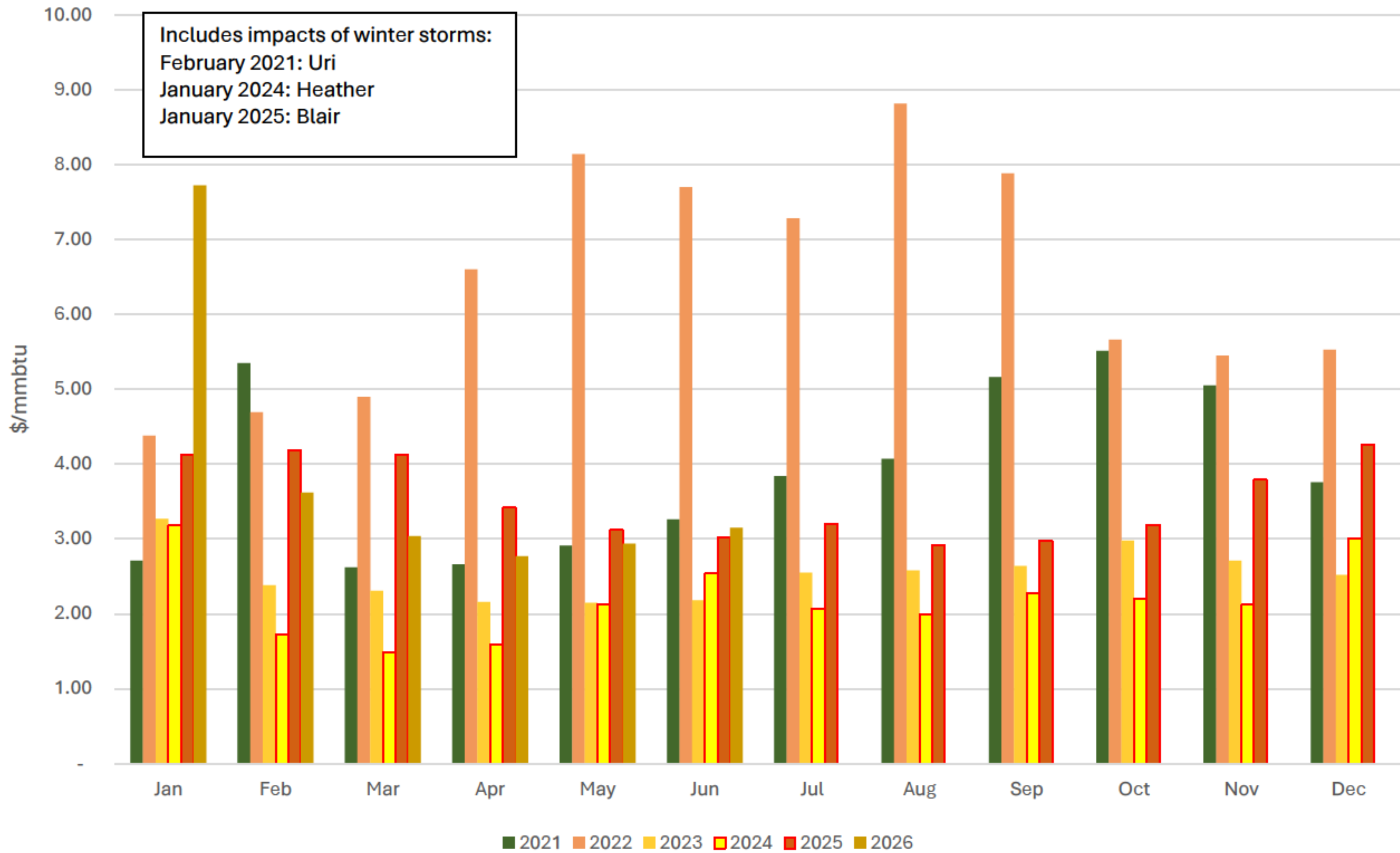
My commission expires: April 26, 2029

ANTHONY R WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2029
PLATTE COUNTY
COMMISSION #17279952

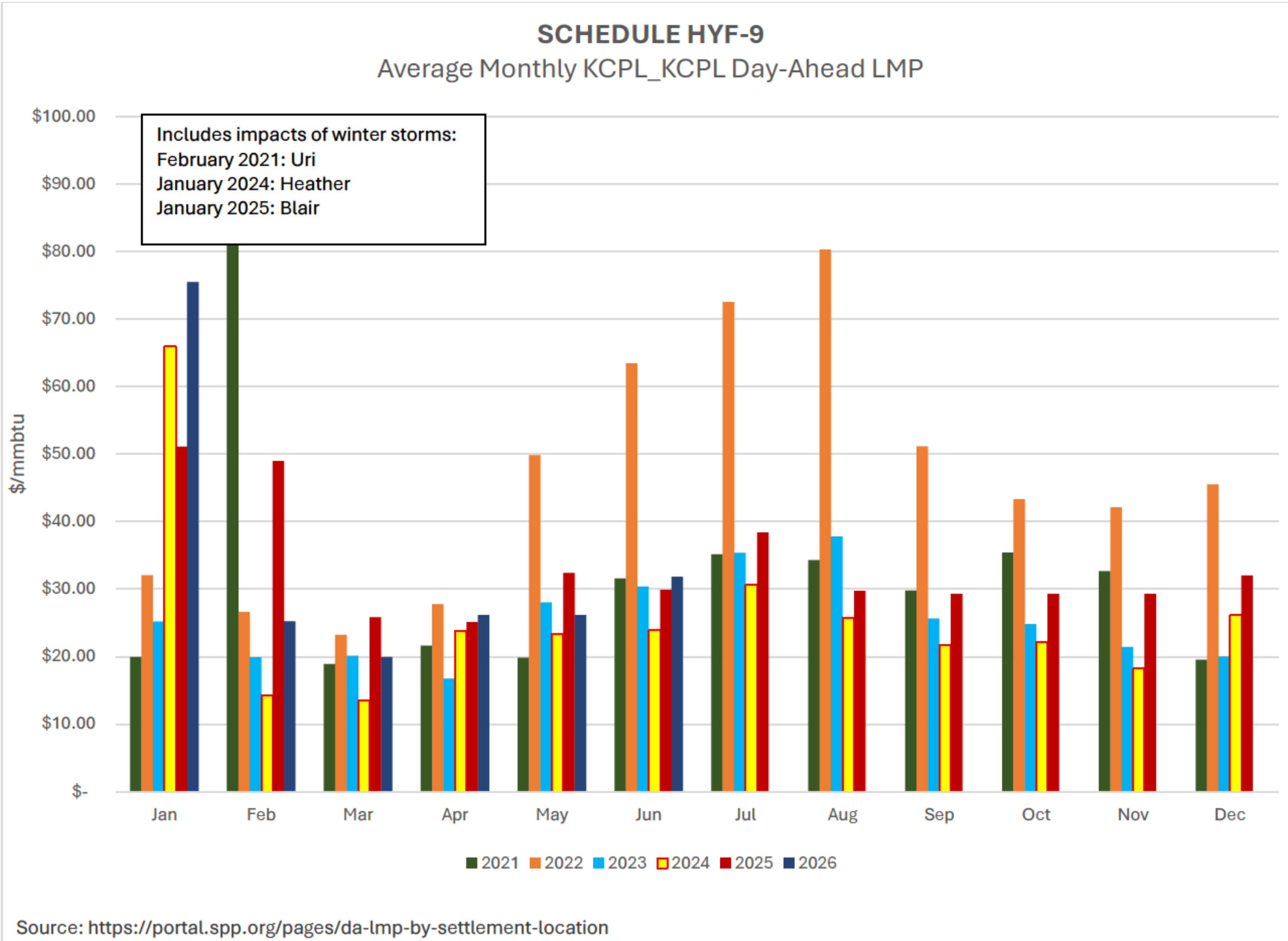

SCHEDULE HYF-7
Average Annual Henry Hub Spot Price
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
$/mmbtu
2.63
2.52
2.99
3.17
2.57
2.03
3.91
6.42
2.54
2.19
3.53
3.87
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026*
* 2026 average represents the average January 2026 to June 2026 spot prices
Source: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

SCHEDULE HYF-8

Average Monthly Henry Hub Spot Price



Source: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm


SCHEDULE HYF-9
Average Monthly KCPL_KCPL Day-Ahead LMP
Includes impacts of winter storms:
February 2021: Uri
January 2024: Heather
January 2025: Blair
$/mmbtu
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2021
2022
2023
2024
2025
2026
Source: https://portal.spp.org/pages/da-lmp-by-settlement-location

CONFIDENTIAL SCHEDULE HYF-10

Wolf Creek Total Venture Historical Hourly Generation

[redacted]

CONFIDENTIAL

CONFIDENTIAL SCHEDULE HYF-11

Staff's Modeled Wolf Creek Generation

[redacted]

CONFIDENTIAL

Evergy Metro, Inc. d/b/a Evergy Missouri Metro

Docket No.: ER-2026-0143
Date: August 11, 2026

CONFIDENTIAL INFORMATION

The following information is provided to the Missouri Public Service Commission under CONFIDENTIAL SEAL:

Document/Page	Reason for Confidentiality from List Below
Foo Rebuttal, p. 8, ln. 19	3, 4, and 6
Foo Rebuttal, p. 14, lns. 5-7	3, 4, and 6
Confidential Schedule HYF-10	3, 4, and 6
Confidential Schedule HYF-11	3, 4, and 6

Rationale for the "confidential" designation pursuant to 20 CSR 4240-2.135 is documented below:

1. Customer-specific information;
2. Employee-sensitive personnel information;
3. Marketing analysis or other market-specific information relating to services offered in competition with others;
4. Marketing analysis or other market-specific information relating to goods or services purchased or acquired for use by a company in providing services to customers;
5. Reports, work papers, or other documentation related to work produced by internal or external auditors, consultants, or attorneys, except that total amounts billed by each external auditor, consultant, or attorney for services related to general rate proceedings shall always be public;
6. Strategies employed, to be employed, or under consideration in contract negotiations;
7. Relating to the security of a company's facilities; or
8. Concerning trade secrets, as defined in section 417.453, RSMo.
9. Other (specify) ____.

Should any party challenge the Company's assertion of confidentiality with respect to the above information, the Company reserves the right to supplement the rationale contained herein with additional factual or legal information.