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Witness: Andrew Rietcheck
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Case No.: ER-2026-0143
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2026-0143

SUR-SURREBUTTAL TESTIMONY

OF

ANDREW RIETCHECK

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
September 2026

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SUR-SURREBUTTAL TESTIMONY

OF

ANDREW RIETCHECK

CASE NO. ER-2026-0143

I. INTRODUCTION AND EXECUTIVE SUMMARY

Q. Please state your name and business address.

A. My name is Andrew Rietcheck. My business address is 818 S. Kansas Avenue, Topeka, Kansas.

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

A. I am employed by Evergy Kansas Central, Inc. and serve as Senior Director of Large Construction and Substation Maintenance for Evergy Kansas Central, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro," "EMM," or the "Company"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc. ("Evergy").

Q. Are you the same Andrew Rietcheck who previously filed rebuttal testimony in this docket?

A. Yes.

Q. On whose behalf are you testifying?

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

Q. What is the purpose of your sur-surrebuttal testimony?

A. The purpose of my testimony is to respond to recommendations made by the Wired Group witnesses Paul Alvarez and David Shapley on behalf of the Office of Public Counsel ("OPC"). Specifically, I will address their recommendations that the Commission should order an additional $73.110 million in disallowances that were not previously provided in OPC's direct filing. Company Witness Buck Reuter will provide testimony concerning the $14.700 million associated with transmission facilities constructed to serve the Panasonic plant.

Q. Have you reviewed the surrebuttal testimony of OPC's consultants Paul Alvarez and David Shapley?

A. Yes, I have.

Q. Do you agree with these additional disallowances from Paul Alvarez and David Shapley which the Company first saw in their surrebuttal testimony?

A. No, I do not. At a fundamental level, the Wired Group's recommendations for equipment replacement are based on a reactive asset management philosophy that generally assumes equipment should remain in service until it outright fails, fails objective testing, or is incapable of providing safe and reliable service. That framework is inconsistent with modern utility asset management practices. There are several other factors taken into consideration when determining if a piece of equipment is demonstrating an imminent inability to provide reliable, cost-effective service. Utilities are expected to proactively manage risk and financial prudence through condition monitoring, engineering assessments, diagnostic testing, lifecycle planning, and asset-health evaluations in order to

mitigate reliability and operational risks before customers experience outages or equipment failures.

II. ADDITIONAL TRANSMISSION DISALLOWANCES FIRST PRESENTED IN OPC SURREBUTTAL

Q. What additional transmission disallowances did OPC first recommend in surrebuttal testimony?

A. OPC witnesses David Shapley and Paul Alvarez recommended for the first time in surrebuttal an additional $87.810 million of transmission-related disallowances: $73.110 million concerning Wolf Creek, Leeds–Winchester, Brunswick–Carrollton, and Claycomo projects, plus ** [redacted] ** associated with transmission facilities constructed to serve the Panasonic plant. These recommendations were not included in OPC's direct case.

Q. Why is the timing of these recommendations significant?

A. OPC elected not to make these recommendations in its direct testimony, where Evergy would have had the ordinary opportunity to respond through rebuttal testimony. Presenting substantial new disallowances for the first time in surrebuttal compresses the Company's review period, requires responses outside the normal testimony sequence, and eliminates the opportunity for Company witnesses to address the factual, engineering, accounting, allocation, tariff, and policy arguments on which OPC relies. Evergy is therefore disadvantaged and prejudiced unless the Commission declines to consider the late adjustments or affords the Company a full and fair opportunity to respond.

A. Wolf Creek Transformers

Q. What is Mr. Shapley's recommendation concerning the Wolf Creek transformers?

A. Mr. Shapley recommends that the Commission disallow $15.21 million associated with the replacement of TX-4, TX-5, and TX-6. He does not challenge the need to replace TX-7,

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which had deteriorating test results. Instead, he characterizes TX-4, TX-5, and TX-6 as three "extra" transformers that the Company replaced prematurely when it undertook the TX-7 replacement. Mr. Shapley calculates his recommended disallowance by taking the Company's approximately $20.28 million share of the overall project cost and allocating three-fourths of that amount to TX-4, TX-5, and TX-6.

Mr. Shapley acknowledges that Wolf Creek's approximately 18-month refueling outages provide opportunities to perform transformer replacement work. However, he contends the Company should have replaced TX-7 during the applicable refueling outage and then continued operating TX-4, TX-5, and TX-6 until each transformer independently required replacement. Under his suggested approach, each later replacement could have been scheduled for a future refueling outage after the Company determined that replacement of the particular transformer had become necessary. He therefore interprets the Company's decision to replace all four transformers as a matter of convenience rather than a sufficiently supported reliability or operational decision. He also cites the remaining netbook value of the retired equipment as an indication that the replacements were premature.

As explained below, Mr. Shapley's characterization does not account for the condition evidence concerning TX-4, TX-5, and TX-6, the related functions performed by the four transformers, the limitations and vulnerabilities of the former station power configuration, or the reliability, redundancy, maintainability, and operational benefits achieved through the comprehensive project.

Q. Mr. Shapley concludes the replacement of the three other transformers, TX-4, TX-5, and TX-6, was simply done out of convenience. What information is Mr. Shapley basing his conclusion on?

A. Mr. Shapley's conclusion appears to be based primarily on a limited portion of the Company's response to OPC Data Request 5033, where the Company explained that a piecemeal replacement strategy would have required additional future outages, repeated engineering and construction mobilizations, increased costs, and increased operational risk. However, Mr. Shapley's testimony does not meaningfully address the remainder of the Company's explanation provided in OPC Data Requests 5033 and 5069. Those responses describe the condition concerns identified on TX-4, TX-5, and TX-6, the transformers' nuclear safety-related functions, the reliability and operational limitations of the existing configuration, TX-6-specific transmission constraints, and the benefits achieved through the comprehensive station power system modernization project.

The Company's evaluation considered transformer age together with dissolved gas analysis results, Doble test results, documented equipment degradation, operational considerations, and the nuclear safety-related functions of the transformers. Consistent with these considerations, industry guidance recognizes that transformer replacement decisions should consider asset condition, age, operational importance, and long-term asset management objectives rather than any single factor in isolation. The Company therefore did not base its decision solely on convenience, nor solely on age.

By reducing the Company's stated justification to a question of convenience, Mr. Shapley does not address the full set of engineering, operational, reliability, safety, and long-term asset management considerations that supported the project. As a result, his

recommendation to disallow costs associated with TX-4, TX-5, and TX-6 is based on an incomplete characterization of the Company's rationale for the project.

Q. Can you provide the full explanation and justification of the Wolfcreek Transformer Project?

A. Yes. As the Company explained in its response to OPC DR 5033 and OPC DR 5069, The Wolf Creek transformer project was developed as a comprehensive modernization of the station power system rather than a one-for-one replacement of Transformer 7. While the deteriorating condition of TX-7 was a significant driver for the project, engineering evaluations also identified aging, reliability, operational, and maintainability concerns associated with TX-4, TX-5, and TX-6. These transformers supported one of Wolf Creek's required offsite power sources and were approaching similar stages in their service life. Evaluations indicated that TX-4, TX-5, and TX-6 exhibited age-related degradation and gassing concerns similar to those identified on TX-7. As a result, replacing only TX-7 would have deferred, rather than resolved, broader reliability concerns affecting the station power system.

The Company’s evaluation considered transformer age together with dissolved gas analysis results, Doble test results, documented equipment degradation, and the nuclear safety-related functions of the transformers. Consistent with these considerations, industry guidance, including EPRI Report No. 1013566, Large Transformer End-of-Expected-Life Considerations and the Need for Planning, recognizes that large power transformer replacement decisions should consider a combination of asset condition, age, operational importance, and long-term asset-management considerations. Accordingly, the Company’s

evaluation and decision to replace TX-4, TX-5, and TX-6 were not based solely on transformer age.

Wolf Creek is a nuclear generating facility and cannot utilize a run-to-failure maintenance strategy for equipment supporting nuclear safety-related and risk-significant functions. Accordingly, replacement decisions are based on equipment condition, reliability, operational requirements, safety considerations, and regulatory obligations. Although TX-4, TX-5, and TX-6 were not part of the normal operating lineup, they remained essential to maintaining a required offsite power source and therefore were subject to the high reliability expectations applicable to nuclear generation facilities.

Additional project-specific considerations supported replacement of TX-4, TX-5, and TX-6 during the same effort. A piecemeal replacement strategy would have required multiple future refueling outages, repeated engineering and construction mobilizations, increased costs, additional operational risk, and reduced overall efficiency. Given the limited availability of refueling outage windows at Wolf Creek, replacing all four transformers as part of a coordinated project represented the most operationally prudent and cost-effective approach

TX-6 presented further concerns beyond age and condition. TX-6 was a unique transformer on the Evergy transmission system, creating long-term maintenance and spare-equipment challenges. In addition, TX-6 had become a transmission constraint as changing system conditions increased power flows through the area, and its connection to the East 345 kV Bus created outage constraints affecting both the Wolf Creek Plant and Wolf Creek Substation. These factors provided further justification for including TX-6 in the overall replacement project.

The approved project retired TX-4, TX-5, TX-6, and TX-7 and installed a new standardized configuration consisting of TX-8, TX-9, TX-10, and TX-11. The new configuration improved reliability, redundancy, maintainability, operational flexibility, and long-term supportability while providing two redundant supply paths for one of the station's required offsite power sources. This approach addressed existing equipment condition concerns, reduced future outage risk, and positioned the station power system for long-term reliable operation.

Q. Can you further describe the benefits to the new configuration?

A. Yes. The replacement project provided significant operational and reliability benefits beyond addressing the condition concerns associated with TX-4, TX-5, TX-6, and TX-7. The new configuration eliminated the limitations associated with the previous station power arrangement by replacing the existing transformers with standardized transformer banks consisting of TX-8, TX-9, TX-10, and TX-11. The upgraded design allows the 69 kV system to be served through parallel transformer arrangements, improving redundancy and operational flexibility. The project also eliminated concerns associated with TX-6 being undersized during periods of high wind generation transfers, a condition that had resulted in transmission constraints and the establishment of an SPP flowgate.

The new configuration further improves maintainability and system resiliency by allowing the East Bus to be removed from service without impacting transformer availability or plant station power. Under the previous configuration, maintenance activities or faults associated with the East Bus could directly affect TX-6 and station power arrangements. The new arrangement removes those constraints and provides greater flexibility during maintenance and outage conditions.

In addition, the project provides two redundant power sources to XNB01 (safety related switch gear bus that receives one of Wolf Creek's required offsite power sources) and two redundant power sources to Switchgear 7 and Switchgear8, enhancing the reliability of station service power supplied to the plant. The configuration also allows TX-8, TX-9, TX-10, and TX-11 to be serviced while maintaining system functionality due to the increased redundancy built into the design. Customer-serving 69 kV transmission lines are similarly supported by redundant transformer sources that can be switched during maintenance activities, improving reliability for both plant operations and the surrounding transmission system.

Q. Could the remaining transformers have been replaced individually during future refueling outages, as Mr. Shapley suggests?

A. That assertion incorrectly assumes that the Company's objective was simply to replace individual transformers. The project objectives extended beyond replacing aging equipment and included implementing a new station power system configuration. A piecemeal replacement strategy would have retained the legacy configuration for an extended period and would not have achieved the reliability, redundancy, operational flexibility, and long-term supportability benefits associated with the selected design. Accordingly, the relevant question is not whether individual transformers could have remained in service longer, but whether retaining the existing configuration would have achieved the project's objectives. It would not have met those objectives.

Q. Was the Company's decision to complete the work as a single project a matter of convenience?

A. No. As I explained above, the decision was based on engineering, operational, reliability, outage-management, and lifecycle-cost considerations, not convenience. The project addressed aging infrastructure, documented equipment degradation, system-reliability objectives, redundancy improvements, and long-term asset-management considerations. Reducing future outage work, engineering efforts, construction mobilizations, testing and commissioning activities, and operational risk are legitimate project benefits and should not be characterized as mere matters of convenience.

Q. Could future replacements have been performed in the same manner as TX-7?

A. Mr. Shapley's conclusion assumes future replacements could be executed under conditions identical to those existing when TX-7 was scheduled for replacement. That assumption does not account for uncertainties involving future equipment condition, outage scopes, procurement lead times, construction mobilizations, system operating requirements, resource availability, and replacement logistics. For a nuclear generating station, prudent asset management requires consideration not only of current equipment condition but also of the long-term reliability, maintainability, and availability of systems that support safe plant operation and protection of the public. The Company determined that implementing the complete configuration in a single project represented the most prudent and cost-effective means of achieving the project's objectives.

Q. Do you agree with Mr. Shapley that convenience does not justify prospective equipment replacement?

A. Yes, convenience alone would not justify replacing utility assets. But convenience was not the basis for the Company's decision. The project addressed aging infrastructure, documented equipment degradation, reliability concerns, operational requirements, and long-term supportability objectives while implementing a new power system configuration designed to improve redundancy and the reliability of offsite power supporting the plant's safety-related electrical systems.

Q. Does the approximately $1 million of remaining netbook value demonstrate that the transformers were replaced prematurely?

A. No. Remaining netbook value is an accounting measure; it is not an indicator of equipment condition, reliability, operational risk, fitness for continued service, or the prudence of a system-modernization project. Utility asset-replacement decisions are based on engineering evaluations, condition-monitoring results, documented degradation, operational considerations, risk management, and long-term asset-management objectives. The existence of remaining netbook value neither negates the benefits achieved through the project nor demonstrates that replacement was premature.

Q. What is your overall conclusion regarding Mr. Shapley's analysis of the Wolf Creek transformer project?

A. Mr. Shapley evaluates the project as though it were a series of independent transformer replacements. It was not. The project was a comprehensive modernization and reconfiguration of the Wolf Creek station power system designed to address aging infrastructure and equipment-condition concerns while improving reliability, redundancy,

operational flexibility, long-term supportability, and the reliability of offsite power sources supporting safe nuclear plant operation. His proposed alternative would have deferred portions of the project and preserved the legacy configuration, thereby failing to achieve the objectives underlying the Company's decision.

B. Leeds–Winchester and Brunswick–Carrollton Transmission Lines

Q. Does the number of poles identified for attention during a particular inspection determine whether a transmission-line rebuild was prudent?

A. No. A pole inspection is one input into an assessment of an integrated transmission line; it is not a comprehensive measure of the line's condition or the prudence of a rebuild. A project evaluation may also consider the age and condition of the line as a whole, conductor condition, structures and foundations, hardware, critical crossings, safety, clearances, line performance, access, constructability, future system needs, and the cost and risk of repeatedly replacing individual components while continuing to operate the remaining aging facilities.

Q. Does Mr. Shapley compare his proposed piecemeal alternative with the actual rebuild scope on cost, risk, reliability, capacity, outage requirements, and lifecycle value?

A. No. Mr. Shapley does not perform a project-specific comparison of the rebuilds against a defined piecemeal alternative. Instead, he relies principally on his characterization of pole age, the number of structures identified for attention through particular inspections, and remaining net book value. That approach does not quantify the cost, outage requirements, safety exposure, construction risk, reliability consequences, or lifecycle implications of repeatedly replacing individual structures and repairing conductor while leaving the remainder of each aging line in service.

Q. What does Mr. Shapley state concerning the Leeds–Winchester transmission-line rebuild?

A. Mr. Shapley states that the average age of the poles replaced was approximately 30 years, that only two of 119 poles failed formal inspections, and that the retired equipment had $169,000 of remaining net book value, or almost 20 percent of original cost. Each statement materially mischaracterizes the project information the Company provided in response to OPC Data Request 5038.

Q. What are the correct facts concerning the Leeds–Winchester project?

A. The average age of the poles was more than 45 years when the line was rebuilt, not 30 years. The rebuild removed 33 structures, not 119 poles. Of the structures inspected before the rebuild, four were identified as needing replacement within the next 18 months. The remaining netbook value was $73,322.80, not $169,000. Of that amount, $73,245.24 was associated with fiber-optic cable that could not be reused because relocation of the dead-end structures changed the cable locations. Thus, only $77.56 of the remaining netbook value related to property other than that fiber-optic cable. These facts were provided in the Company's response to OPC Data Request 5038.

Q. Why was the Leeds–Winchester line rebuilt?

A. The line was rebuilt because of its overall age and condition. It was primarily a 1950s-vintage line that had reached the end of its useful service life. The line also includes critical crossings over interstate highways and several major throughways, portions of which were more than 65 years old. Those conditions required the Company to evaluate the integrity and risk of the line as a complete operating asset, rather than limiting its assessment to the number of poles identified for near-term attention through one inspection process.

Q. What does Mr. Shapley state concerning the Brunswick–Carrollton transmission-line rebuild?

A. Mr. Shapley states that the average pole age was 50 years and was not relatively old, points to an asserted 98-year-old pole on EMM's system, and states that only eight of 254 poles failed formal inspections. Those statements omit material facts provided in response to OPC Data Request 5040 and do not account for the condition of the conductor.

Q. What are the correct facts concerning the age and condition of the Brunswick–Carrollton facilities?

A. The majority of the poles were 1951 vintage and were placed in service in 1953. Fewer than one percent of the approximately 20,000 poles on EMM's transmission system are older than the poles replaced in this project. Further, the oldest wood pole on the EMM transmission system is 1945 vintage and is currently approximately 81 years old, not 98 years old. The project therefore involved facilities at the extreme upper end of the age distribution on EMM's transmission system.

Q. Did only eight structures present condition concerns?

A. No. Eight structures were identified during the annual visual inspection as requiring attention within the next 18 months. In addition, the 2018 detailed intrusive inspection identified 20 structures that had deteriorated below their minimum design strength and were tagged as rejected. Focusing only on the eight structures from the annual visual inspection omits the rejected structures identified through the more detailed intrusive inspection. The information concerning those inspections was provided in the Company's response to OPC Data Request 5040.

Q. Were pole conditions the only asset-health concern supporting the Brunswick–Carrollton rebuild?

A. No. The inspection worksheets did not capture the condition of the conductor. Previous maintenance work had identified widespread broken conductor strands. The condition had become sufficiently serious that many planned individual structure replacements were canceled because transferring the existing conductor to new structures presented safety concerns. That evidence demonstrates why counting poles identified through a particular inspection does not measure the condition of the line as a whole and does not establish that a rebuild was premature.

Q. What is your conclusion regarding Mr. Shapley's recommended disallowance for the Leeds–Winchester transmission-line rebuild?

A. The Commission should reject the recommended disallowance. Mr. Shapley's analysis rests on incorrect pole-age, structure-count, inspection, and remaining-net-book-value figures and does not evaluate the line as an integrated transmission asset. The Company's decision reasonably considered the line's overall age and condition, its critical interstate and major-throughway crossings, and the risks and lifecycle implications of continuing piecemeal work on aging facilities. His testimony does not establish that the rebuild was premature or imprudent.

Q. What is your conclusion regarding Mr. Shapley's recommended disallowance for the Brunswick–Carrollton transmission-line rebuild?

A. The Commission should reject that recommended disallowance as well. Mr. Shapley focuses on a single inspection count and an inaccurate comparison to the oldest pole on the system, while omitting the 20 structures rejected through detailed intrusive inspection and

the widespread broken conductor strands that created safety concerns and prevented planned individual structure replacements. The project involved facilities at the extreme upper end of EMM's transmission-pole age distribution, and the complete condition record supports the Company's decision to rebuild the line.

C. Claycomo Substation

Q. Is Mr. Shapley's conclusion that a ring-bus configuration is only marginally more reliable supported by a project-specific analysis of Claycomo?

A. No. His testimony does not identify a project-specific reliability, operational, protection, maintenance, contingency, safety, or constructability analysis demonstrating that the Claycomo configuration change lacked value. The absence of Mr. Shapley's preferred dollar-denominated benefit-cost study does not establish that the engineering justification was absent or that the project was imprudent.

Q. What assets and condition concerns principally drove the Claycomo modernization project?

A. The principal assets for which age, asset-health, and condition considerations drove replacement were Transformers TX-7, TX-9, and TX-56; the associated 161 kV circuit switchers; and related protection and control equipment. The project addressed aging transformer and station infrastructure, including a substantial population of legacy electromechanical relays and protection systems that had become increasingly obsolete and difficult to maintain. The transformers ranged from approximately 36 to 57 years old when replaced: TX-9 was manufactured in 1964, TX-56 in 1975, and TX-7 in 1985. The Company evaluated those ages together with the assets' condition assessments, diagnostic

results, operating functions, maintainability, and the risks associated with continued operation.

Q. What did the condition assessments show for the three transformers?

A. TX-7 exhibited active gassing, elevated moisture and oil-quality concerns, and diagnostic indicators consistent with thermal-fault activity. TX-9 showed insulation-system aging, degraded fluid quality, elevated furan indicators, and significant load-tap-changer diagnostic concerns. In particular, its selector compartment received a condition rating of 4, acetylene concentrations were elevated, and the diagnostic findings called for immediate investigation. TX-56 also exhibited age-related oil-quality and gassing concerns, although its diagnostic results were less severe than those observed on TX-9. Collectively, the transformers' advanced ages and condition-assessment results demonstrated developing internal degradation and supported replacement to improve long-term reliability and reduce operational risk.

Q. Why was it reasonable to address the protection and control equipment as part of the same project?

A. The transformer replacements were not isolated from the balance of the station. The associated 161 kV circuit switchers and a large population of legacy electromechanical relays and protection systems were also aging, increasingly obsolete, and becoming more difficult to maintain and support. Addressing those interdependent assets through a coordinated modernization avoided retaining obsolete protection and control equipment around newly installed primary equipment and improved the station's long-term reliability, maintainability, and supportability.

Q. What operating benefits did the ring-bus configuration provide, including isolation capability, maintenance flexibility, contingency performance, protection functionality, and reduced exposure to a single bus event?

A. In addition to addressing deteriorating and obsolete assets, the ring-bus configuration improved the station's ability to isolate equipment and portions of the bus for faults or maintenance while keeping unaffected facilities in service. It reduced exposure to a single bus event, enhanced contingency performance, provided greater maintenance and operating flexibility, and enabled modernized protection functionality. Those benefits must be considered together with the transformer, circuit-switcher, and protection-system condition evidence. Mr. Shapley's characterization of the ring bus in isolation does not evaluate the integrated purpose or benefits of the Claycomo modernization project.

Q. Is the retired plant's remaining net book value evidence of imprudence, or is it an accounting fact that must be considered together with the project's condition, function, risk, and benefits?

A. It is an accounting fact, not proof of imprudence. Remaining net book value does not measure transformer insulation condition, dissolved-gas activity, oil quality, load-tap-changer condition, equipment obsolescence, maintainability, protection-system functionality, or the operational risk of continuing to operate an aging station configuration. The prudence inquiry must consider the information reasonably available when the Company made its decision, including the age and condition of TX-7, TX-9, and TX-56, the associated circuit switchers, the obsolete protection and control equipment, and the reliability and operating benefits of the modernization. Remaining net book value does not negate that evidence.

Q. What is your overall conclusion regarding OPC's additional transmission disallowances?

A. The recommendations should be rejected because they were first presented after OPC's direct case and because they rely on selective indicators, generalized assumptions, and unsupported proxies rather than complete project-specific engineering and cost evidence. The challenged investments should be evaluated on the information reasonably available when the decisions were made, the alternatives considered, the risks addressed, the system and customer benefits obtained, and the applicable tariffs and allocation requirements—not through hindsight or a single preferred analytical method.

Q. Does that conclude your 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 ANDREW RIETCHECK

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Andrew Rietcheck, being first duly sworn on his oath, states:

1. My name is Andrew Rietcheck. I work in Topeka, Kansas, and I am employed by Evergy Kansas Central, Inc. as Senior Director of Large Construction and Substation Maintenance.

2. Attached hereto and made a part hereof for all purposes is my Sur-Surrebuttal Testimony on behalf of Evergy Missouri West consisting of nineteen (19) 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.

Andrew Rietcheck

Subscribed and sworn before me this 23rd day of September 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

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

Docket No.: ER-2026-0143
Date: September 10, 2026

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Document/Page	Reason for Confidentiality from List Below
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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;

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