Exhibit No.:
Issue: Substation Disallowance
Witness: Andrew Rietcheck
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

ANDREW RIETCHECK

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
August 2026

TABLE OF CONTENTS

REBUTTAL 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. On whose behalf are you testifying?

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

Q. What are your responsibilities?

A. As Senior Director of Large Construction and Substation Maintenance, I have leadership responsibilities for the Transmission and Substation Major Project Team including the Project Management, Field Construction, and Real Estate Services that functionally support transmission and substation projects. In the Substation Maintenance Group, I have responsibilities for the Substation Plant Maintenance/Construction including support groups of Scheduling and Planning, Asset Management, and Compliance. My responsibilities are for all four Evergy jurisdictions in Kansas and Missouri.

Q. Please describe your education, experience and employment history.

A. I received a Bachelor of Science Degree in Civil Engineering from Kansas State University in 1995. I am a Professional Engineer licensed in the State of Kansas. Prior to joining Evergy (started with Evergy predecessor, Westar Energy) in 2010, I held various roles in public works management, construction management, and construction contractor leadership. During my first 3 years at Westar Energy, I served as a Senior Engineer supporting generation. Since 2013, I have held various roles in transmission and substation including Project Manager, Director of Field Construction, Director of Substation Maintenance, and since 2024, my current role of Senior Director of Large Construction and Substation Maintenance.

Q. Have you previously testified in a proceeding at the Missouri Public Service Commission ("MPSC" or "Commission") or before any other utility regulatory agency?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal 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 $29.424 million in disallowances for substation projects.

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

A. Yes, I have.

Q. Do you agree with the recommendations from Paul Alvarez and David Shapley?

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. DISCRETIONARY SPENDING/RISK-INFORMED BENEFIT-COST ANALYSIS

Q. How does Mr. Alvarez define discretionary vs. required spending?

A. Mr. Alvarez's comparison of discretionary and required spending is extremely black and white. He explains that infrastructure replacement projects should generally be considered discretionary unless an asset has already failed or demonstrated an inability to provide safe and reliable service.[1] Mr. Alavarez claims that discretionary investments in Transmission and Distribution ("T&D") are not required for safe and reliable service.

Q. Do you agree with Mr. Alvarez's definition of discretionary spending?

A. No. Evergy's strategy for deploying capital is directed toward maintaining and improving reliability performance, operational safety, and grid resiliency. Mr. Alvarez effectively defines an investment as discretionary unless it is directly associated with equipment failure, failed testing, capacity expansion, regulatory mandates, or customer requests for service. That definition does not reflect how utilities manage aging infrastructure in practice and fails to recognize condition-based asset management strategies designed to proactively address increasing risk before failures occur.

Q. Is Mr. Alvarez's narrow view on discretionary and required investment common in the industry or other utilities?

A. No. Guidance from the Institute of Electrical and Electrics Engineers ("IEEE"), the Electrical Power Research Institute ("EPRI"), and the International Council on Large Electric Systems ("CIGRE") recognize that prudent replacement decisions are frequently driven by asset condition, degradation trends, criticality, probability of failure, consequence of failure, maintainability, obsolescence, operational requirements, and lifecycle risk before actual failure occurs. Similarly, International Organization for Standardization ("ISO") 55000 Asset Management Standards define asset management as balancing risk, cost, and performance throughout asset lifecycle. These ISO 55000 principles are reflected throughout utility asset management programs and reinforce that prudent replacement decisions frequently occur before actual equipment failure.

By focusing primarily on economic screening methodologies and high-level reliability metrics, Mr. Alvarez largely overlooks the condition-based asset management processes that utilities employ to identify and mitigate risk before customer outages, equipment failures, or operational disruptions occur.

Q. Mr. Alvarez testifies that the Missouri legislature has already provided guidance to utilities regarding the use of cost-benefit analysis for discretionary capital spending. Do you agree with this statement?

A. Mr. Alvarez alleges that the requirements in RSMO Chapter 393.1075(4) should be applied to discretionary spending targeted toward T&D reliability. I disagree with this position. The purpose of RSMO 393.1075 was to allow for the recovery of reasonable demand-side management programs and to treat the value of those investments equal to traditional supply and delivery infrastructure investments. EMM witness Andrew Alexander will further discuss this topic in his Rebuttal Testimony. The insinuation that the Missouri legislature has provided guidance on utility service reliability spending is unsupported by any facts or citation.

Q. Mr. Alvarez recommends that utilities use a risk-informed benefit-cost analysis to identify prudent discretionary capital investments based on benefits. He references the U.S. Department of Energy's online Interruption Cost Estimator ("ICE Calculator") tool as the most common tool used for this purpose. What is Evergy's opinion regarding this recommendation?

A. Every agrees that this method is a proper way of identifying and prioritizing aging asset replacement projects. EMM has leveraged AssetLens software to facilitate prioritization of projects as its software utilizes data from the ICE Calculator to compute customer benefits associated with asset replacements and compares those benefits to an estimated cost. EMM Witness Andrew Alexander discusses this topic further in his Rebuttal Testimony.

Q. Do you agree with Mr. Alvarez's philosophy on asset management?

A. No. Mr. Alvarez substitutes a theoretical economic model for the condition-based engineering and asset health evaluation processes that are widely recognized throughout the utility industry as essential components of prudent asset management. It would be highly irresponsible to reduce EMM's current asset management process to either a single theoretical equation or a reactive policy of only replacing equipment once it fails.

Mr. Alvarez frequently equates the absence of formal risk-informed benefit-cost analyses with a lack of governance or rigor. However, utility asset management decisions may be supported through health indexing, engineering assessments, condition evaluations, reliability reviews, diagnostic testing, maintenance history analysis, risk ranking, capital planning processes, and management review processes. The absence of a particular economic screening methodology does not establish the absence of prudent engineering review or governance.

Q. Can you expand on EMM's asset management process?

A. Yes. Consistent with accepted utility industry asset management practices, Evergy utilizes a proactive asset management program that utilizes condition assessments, health evaluations, diagnostic testing results, outage and maintenance history, failure mode analysis, criticality assessments, and engineering reviews when evaluating asset maintenance/replacement options. Rather than waiting for equipment to fail, these processes are designed to identify elevated failure/operational risks early and develop a planned repair/replacement strategy. By utilizing this approach, Evergy is able to proactively plan and manage assets to achieve the most economical approach for grid reliability and asset performance. Failure to employ a proactive asset management approach results in greater reliance on reactive maintenance and emergency replacements, which are typically more costly and can lead to longer service interruptions for customers.

III. SUBSTATION EQUIPMENT REPLACEMENTS

Q. Please summarize Mr. Shapley's recommended disallowances for substation equipment replacement projects.

A. Mr. Shapely recommends disallowances of $29.424 million in substation equipment replacement projects in four categories: A) $3.5 million for the purchase of redundant power transformer spares; B) $7.9 million to replace rather than rebuild transformers; C) $12.8 million to replace transformers without adequate justification; and D) $5.1 million to replace circuit breakers without adequate justification. I will respond to each disallowance category separately.

A common theme throughout Mr. Shapley's testimony is the assumption that utility equipment should remain in service unless it has failed or failed an objective test. That assumption does not reflect modern utility asset-management practices or the EMM asset management program. As previously noted, industry guidance from IEEE, EPRI, and CIGRE recognizes that prudent asset decisions are based on condition, risk, remaining life, consequence of failure, asset criticality, maintenance history, and diagnostic trends—not simply whether an asset has failed an inspection or test. EMM and other utilities routinely replace assets before catastrophic failure occurs in order to mitigate increasing reliability, operational, and safety risk.

The majority of Mr. Shapley's recommendations are based on generalized assumptions regarding what could have been done differently rather than an evaluation of the complete engineering evidence supporting the Company's decisions. Throughout his testimony, he assumes 1) assets should remain in service unless they have failed or fail objective tests, 2) assumes refurbishment provides equivalent lifecycle value to replacement, 3) assumes repairs would have been sufficient to resolve emerging asset-health concerns, 4) assumes spare inventories are excessive without evaluating inventory planning criteria, and 5) assumes replacement programs provide limited value because relatively few outages are coded as equipment failures. These assumptions are inconsistent with modern condition-based asset management practices, which rely on asset health, probability of failure, consequence of failure, maintenance history, projected remaining life, operational requirements, and risk mitigation strategies to address deteriorating infrastructure before customers experience outages or equipment failures. Furthermore, EMM witness Andrew Alexander's testimony discusses a thorough review of Mr. Shapley's analysis compared to EMM's outage data and reaffirms that equipment failure is the leading cause of customer outages during normal, blue-sky operating conditions. This further supports the conclusion that proactively identifying and replacing high-risk assets before failure provides meaningful reliability benefits to customers and represents a prudent use of resources.

Mr. Shapley substitutes generalized assumptions and age-independent pass/fail philosophies for the condition-based, risk-informed asset management practices that are widely recognized throughout the electric utility industry.

For each of the recommended disallowance categories, a response is provided that first addresses EMM philosophies and practices around that category and then more specific rebuttal details for each specific item.

A. Redundant Transformer Spares

Q. Mr. Shapley criticizes EMM for adding two spare power transformers of the same specification. Why does Evergy believe it is prudent to maintain both of these spare transformers?

A. Mr. Shapley's recommendation is based on several unsupported assumptions. He acknowledges that he did not evaluate Evergy's Spare Transformer Inventory Program, yet he concludes that inventory levels are excessive. Evergy's spare transformer acquisitions/inventory targets are not driven by a single factor. Evergy's Transformer Asset Management Program evaluates transformer fleet demographics (including identifying spare configurations that are interchangeable to support as many in service transformers/substations as possible), in service populations, asset condition and health trends, failure risk, criticality to system operations, projected retirements/planned replacements, and other restoration options (or lack thereof) if an unplanned failure occurs. As part of the Company's failure risk assessment, EMM may identify in-service transformers that are planned for future replacement but exhibit indicators of elevated risk of imminent failure. In those circumstances, the Company may purchase a replacement transformer and temporarily classify it as a "spare" so it is immediately available if the in-service unit fails before the planned project and is ultimately transferred from "spare" inventory into service when the replacement project is executed. This strategy is utilized when the risk of imminent failure is identified ahead of the planned project schedule and has proven beneficial due to the extended transformer lead times in the industry. These considerations are consistent with accepted utility asset-management practices, which recognize that transformer fleet planning must balance reliability, operational readiness, contingency response capability, and long-term asset management objectives.[1]

Mr. Shapley also assumes that mobile transformers function as direct substitutes for permanent spare transformers, and that mobile transformers exist primarily to respond to transformer failures. In practice, the Company's mobile transformers support a variety of operational needs beyond emergency response, including planned equipment replacements, temporary solutions for unexpected new load growth, and substation rebuild projects. The availability of mobile transformers enables EMM to complete these projects more efficiently, minimize or avoid customer reliability impacts during construction, and reduce overall project costs. As a result, mobile transformers provide value not only during unplanned equipment failures but also by enhancing the Company's ability to safely and cost-effectively execute planned system improvements.

Q. Does Mr. Shapley identify which project or spare power transformers he is recommending for disallowance?

A. No. Mr. Shapley does not specifically identify by Project or other specific identifying information which two spare power transformers he is recommending for disallowance. Based on dollar amounts and supporting footnotes, the Company understands Shapley is referring to Project 20101796 Waukesha Spare 30MVA 161/13kV Transformer and Project M107176050 Hitachi Spare Transformer. Both of these spare transformers are 161/13KV voltage class transformers, and it is correct that these could be considered "redundant". For context, EMM currently has one hundred and thirteen (113) 161/13kV class transformers in service with eleven of those transformers having some type of

[1] CIGRE Technical Brochure 962, *Guide for Transformer Maintenance*; CIGRE Technical Brochure 248, *Economics of Transformer Management.*

conditional concern or performance trends being tracked in our asset management program. The Project 20101796 Waukesha 30MVA 161/13KV Transformer was purchased as a planned spare for this voltage class and will be maintained as a spare. In addition to this spare, EMM has also used a 56MVA 161/13.09KV transformer that is classified as a spare in this voltage class. Both of these spare transformers (1 new, 1 used) are necessary and prudent spares as the 30MVA has a smaller footprint and is necessary in many of the existing 30MVA applications as there is no physical room available to install the 56MVA option. Conversely, the 56MVA transformer is necessary for applications where a 30MVA unit would be incapable of carrying the required load during peak conditions. Accordingly, the two transformers are not interchangeable across all applications and serve complementary reliability purposes within the EMM system.

Q. Why did EMM order these spares?

A. As part of Evergy's transformer risk assessment, EMM identified the transformer associated with Project M107176050 as exhibiting elevated failure risk while a planned replacement project was progressing through the design and planning stages. EMM procured a replacement transformer as a spare, but it is designated for a Hawthorn Substation Transformer Replacement Project, which is currently planned for execution in 2027. This planned project will replace two existing 1950 transformers that are in poor health and exhibiting signs of imminent failure with the single M107176050 Transformer. Both of the existing 1950 transformers have combustible gasses, paper degradation, oil leaks, increasing moisture, and other concerns which indicate an elevated imminent failure risk (sudden failure would not be surprising). Both transformers were originally installed as Hawthorn generator step-up transformers ("GSUs") and were later converted to load serving assets by tapping the 13.2kV generator bus to supply distribution load. Due to the original GSU configuration (Y-D configuration requiring zig-zag transformers) neither of these transformers are feasible candidates for rebuilding. With the elevated risk of failure, long transformer lead time, amount and type of load served by the existing transformers, the decision was made to have this transformer delivered in 2025 and available if the unplanned failure occurs prior to planned work starting next year.

Based on this additional information, EMM has demonstrated justification and prudence in the purchase of these two "spare" transformers in 2024 and 2025.

B. Replacing Rather Than Rebuilding Transformers

Q. Mr. Shapley indicates EMM should consider rebuilding rather than replacing power transformers. What is Evergy's justification for replacing in lieu of rebuilding the four power transformers that Mr. Shapley recommends 50% cost disallowance on?

A. Mr. Shapley's recommendation assumes that transformer rebuilding is preferable whenever the estimated rebuild cost is lower than the cost of replacement. Industry practice does not support that assumption. Evergy makes transformer replacement versus refurbishment/rebuild decisions on a case-by-case basis considering asset condition, insulation health, overall transformer design, reliability risk, system requirements, and lifecycle economics. Industry guidance recognizes refurbishment/rebuilds as life-extension measures, not necessarily a means of creating an asset equivalent to a new transformer with the same expected service life. Mr. Shapley does not appear to have evaluated many of the technical and operational factors commonly used by utilities to determine whether rebuilding or replacement is the prudent alternative. These factors include dissolved gas analysis ("DGA") results, furan testing, degree of polymerization, fluid quality, insulation condition, age and projected remaining life all components, maintenance history, loading history, asset criticality, manufacturer support, spare-part availability, future capacity requirements, and long-term reliability risk. Consistent with industry asset-management practices, Evergy's transformer health evaluations incorporate numerous condition-based indicators rather than relying solely on initial cost considerations. Consequently, Mr. Shapley's conclusion that these transformers should have been rebuilt rather than replaced is not supported by an evaluation of the other underlying items just noted. Instead, his recommendation is based primarily on a generalized assumption that rebuilding costs less than replacement. Without demonstrating that rebuilding would have adequately addressed the identified condition concerns, met future system requirements, and provided a comparable risk and performance profile over the asset's remaining life, there is insufficient basis to conclude that rebuilding would have been the more prudent alternative.

Q. Does EMM have the capability to refurbish transformers?

A. EMM has in-house capability to refurbish transformers and utilizes this capability when it is the best long-term decision considering all factors that go into our asset management program. I specifically use the word "refurbishment" here to refer to items that can typically be completed on the pad in the substation without transporting the transformer back to a manufacturer facility. This refurbishment work includes removing oil to complete internal inspections, repairing internal connections issues, repairing/replacing internal insulation on leads, gasketing/leaking issues, processing/drying of oil to remove moisture from oil and paper insulation, load tap changer ("LTC") repairs, LTC replacements with factory rebuilt LTCs, and similar work scopes.

Q. How does transformer refurbishing compare with a rebuild?

A. Transformer rebuilding is typically considered to be more extensive than a refurbishment and requires the transformer to be shipped to the original equipment manufacturer ("OEM") or other rebuilder. At this point, the transformer is typically untanked (welded top removed and all internal components including windings/core removed). In today's environment of high transformer demand, total refurbishment is typically not an economically feasible or timely option. Many OEMs (if not all) will not perform factory substation class transformer rebuilds due to demand they have for new transformers and their limited resources. Non-OEM rebuilders do not always have the proper resources and expertise to rebuild a transformer that can be expected to provide long term reliability. Additionally, non-OEM rebuilders do not have the full original OEM design information, so they must perform reverse engineering as part of the process. Some older transformers are not desirable to rebuild as their original internal configuration, design assumptions, and construction methods have proven to be unreliable for long term performance. Many times, the existing transformer tank size/layout doesn't allow these identified unreliable items to be addressed in a rebuild. For example, part of Evergy's territory (including EMM) utilizes a dual secondary winding, dual load tap changer ("LTC") configuration (for simplicity this will be referred to as "dual LTC transformer" in follow-on testimony). Dual LTC transformers are subject to substantially higher mechanical forces than standard transformer designs due to their additional windings and switching components, increasing the risk of winding movement, distortion of clamping structures, and long-term equipment degradation. These units also present operational and maintenance challenges, including legacy configurations where maintenance on a single LTC could require the entire transformer to be removed from service. The Company has documented instances of severe failures associated with these designs, including catastrophic events that can lead to extended customer outages and potential environmental impacts from insulating oil release. The last violent and catastrophic failure of a dual LTC transformer occurred in 2019. The force of the failure split the transformer tank open and forcefully sprayed oil and other internal components into the substation. Given these risks, replacement with standardized transformer designs provides a more reliable, maintainable, and cost-effective long-term solution while reducing operational, customer, and environmental exposure. For these reasons, dual LTC transformers are not candidates for off-site rebuilds. On pad refurbishments and maintenance activities have historically been completed with the dual LTC transformers.

Q. Does Mr. Shapley identify which transformers he is recommending for disallowance?

A. Mr. Shapley does not specifically identify by Project or other specific identifying information which transformers he is recommending for disallowance. Based on dollar amounts and footnotes in his testimony, I believe Mr. Shapley is recommending the transformers listed below for 50% disallowance. A brief summary is provided for each of the transformers.

Asset	50% Cost ($M)	Summary
Brunswick TX2	2,052.0	1968 Transformer, deteriorating paper, main tank operating at high temperatures, moisture issues, poor health condition assessment, oil reports support condition replacement. Would have required complete rebuild with windings. Replaced with new transformer meeting current specs.
Midtown TX12	4,474.7	1960 Transformer, significant LTC issues, oil reports indicated other issues occurring in main tank, oil reports support age and condition replacement. Due to limited life expectancy of main tank replaced with new transformer in lieu of investing in rebuilt LTC and follow up complete rebuild with windings.
Malta Bend TX1		1969 Transformer, dual LTC with issues, significant nitrogen leaks, oil reports support age and condition replacement. Dual LTC not a consideration for rebuild.
Glasgow TX2	1,421.9	1970 Transformer, deteriorating paper insulation, arcing in main tank, continued degradation noted through oil analysis, poor health condition, assessment, oil reports support condition replacement. Would have required complete rebuild with windings, etc. Replaced with new transformer meeting current specs.

As indicated by the summaries, the Malta Bend transformer was not a candidate for rebuild due to the dual LTC configuration. The remaining transformers would have required a complete rebuild that included removing and replacing a vast majority of the components in the tank. As previously noted, in today's environment, complete untanking rebuilds are typically not economically feasible when compared to a new unit. Some industry personnel will continue to quote a 50% cost for rebuilds, which may be feasible and realistic with smaller pole mount transformers, but not for substation class transformers. The standalone factory cost of substation transformers rebuilds typically cost 70%-plus of a new unit and carries more reliability uncertainty due to the core, tank, and other structural components being reused. When tear down, removal, transportation to and from, installation, re-assembly are considered in the all in cost, rebuilds will run 80-90% the cost of new transformer while providing a portion of the expected service life of new transformer. Additionally, warranty is significantly less with a rebuilt transformer (1-2 years at most) compared to a new transformer (5-7 years in our current agreements). As a result, the return on investment for a major rebuild is substantially lower than replacement with new. Based on this data, EMM has demonstrated justification and prudence in the replacement of these transformers in lieu of sending them off to a factory for complete rebuilds.

C. Replacing Transformers Without Adequate Justification

Q. Mr. Shapley indicates EMM had five transformer replacement projects that were unsupported. Which projects were identified?

A. Mr. Shapley does not specifically identify by Project or other specific identifying information which transformers he is recommending for disallowance. We have deduced from the dollar amounts and footnotes that he is recommending the transformers listed below for disallowance. A brief summary is provided for each of the transformers.

Asset	Cost ($M)	Summary
Weatherby TX12	2,374.7	2003 Transformer, dual LTC
Blue Valley TX12	3,512.2	Unit rebuilt in 1995 with rewind, dual LTC
Drexel Corners TX1, TX2	2,990.6	(2) 1953 units displaying partial discharge in main tank, paper insulation degradation, acetylene gas, atmospheric exchange, oil reports support condition replacement
Merriam TX34	3,995.60	1964 Transformer, dual-tap LTC, partial discharge in main tank, oil quality issues, oil reports support condition replacement

Q. Why does Mr. Shapley recommend the disallowance of these transformers?

A. Mr. Shapley's recommendation to disallow these transformer replacement projects is based on generalized assumptions regarding transformer life expectancy, his view on transformer refurbishment practices, and the significance of isolated objective tests rather than an evaluation of the specific facts and comprehensive data associated with the transformers at issue. Throughout his testimony, Mr. Shapley repeatedly asserts that rebuilt transformers are effectively equivalent to new transformers and can be expected to provide service life comparable to new equipment. Whether a transformer is original OEM or a rebuilt transformer, decisions on maintenance/replacement strategies should be based on the comprehensive health data and trends that have been observed on the transformer since the time of original build or time of rebuild. With a proactive asset management program like EMM's Transformer Asset Management Program, the data is used to make and support these decisions. With this data, blanket statements like "Twenty years of operation is nothing for a new or rebuilt transformer" are not relevant to the decision-making process.

Q. Does asset age alone determine whether a transformer should be replaced?

A. No. Asset age is only one factor considered in Evergy's Transformer Asset Management Program. Transformer service life varies significantly based on factors such as design, loading history, operating environment, maintenance history, fault exposure, and measured degradation trends. As a result, replacement decisions are driven by comprehensive condition and risk assessments rather than age alone.

Mr. Shapley's reliance on the existence of one transformer installed in 1948 as evidence that other transformers should remain in service is similarly unsupported. What this information does support is that if the health data shows no concerning trends or pending failure, EMM will leave these assets in service well beyond their expected life and depreciation timeline – other instances of this have also been highlighted in my previous testimony. What EMM has seen since implementing a proactive asset management program is that transformer service life varies significantly depending upon many factors including design, duty cycle, loading history, operating environment, maintenance history, fault exposure, and other degradation trends that can be tracked through DGA and electrical testing. With this higher level of data, asset age does not constitute a valid benchmark for evaluating the prudence of replacement decisions.

Q. Does the presence of single test result or condition indicator necessarily mean a transformer can be safely repaired?

A. No. Transformer condition assessments are based on the evaluation of all available engineering and diagnostic information. With respect to transformers exhibiting acetylene in oil, I agree with Mr. Shapley's acknowledgement that acetylene is evidence of arcing, yet he assumes that the condition likely resulted from a relatively benign issue such as a loose connection. The presence of acetylene is not merely evidence of a potentially correctable issue; it is also a potential indicator of high-energy arcing activity within a transformer. Depending upon the magnitude, trend, location, and associated diagnostic findings, the presence of acetylene may be an indication of other issues including insulation damage/deterioration, winding damage, connection failures, internal faults, or other conditions that create an unacceptable reliability risk. Evaluation of all of the data and consideration of the root cause leading to arcing is important in deciding the most prudent path forward. Mr. Shapley's testimony assumes that the Company proceeded directly to replacement without first performing additional engineering evaluation, diagnostic testing, inspection activities, repair efforts, or root-cause investigation. All of these processes/evaluations are EMM standard operating procedure when reviewing transformer health data and deciding on the best path forward.

Additionally, Mr. Shapley oversimplifies the relationship between a transformer and its load tap changer. While the LTC is a distinct component that can often be repaired or replaced independently, the prudence of doing so depends on the condition and remaining life of the transformer itself. Utilities do not evaluate LTC replacement in isolation. Rather, they consider whether investing substantial capital into the LTC is justified given the age, health, reliability, maintenance history, and future service expectations of the entire transformer. Where the transformer remains a viable long-term asset, the Company will refurbish or replace LTCs. When the main transformer itself is nearing end-of-life or exhibiting broader condition concerns, LTC replacement simply defers a more comprehensive transformer replacement that will ultimately be required. Mr. Shapley does not demonstrate that he evaluated any of these factors before recommending disallowance.

Mr. Shapley has made several broad assumptions in recommending disallowance of these transformer replacements, as his testimony does indicate that he reviewed the Company's condition assessment records. EMM's Transformer Asset Management Program considers a wide range of data analysis that can include dissolved gas analysis, furan testing, degree of polymerization indicators, fluid quality assessments, moisture content, combustible gas trends, loading history, maintenance history, corrective maintenance activity, transformer criticality, consequence of failure, spare availability (or lack thereof), system reliability impacts, future load-serving requirements, and long-term lifecycle risks. Without evaluating all data associated with the transformers in question, it is not possible to determine whether transformer replacement costs should be disallowed.

Q. Please provide an explanation as to why the transformers were replaced.

A. The Merriam transformer and Drexel Corner transformers were 62 and 71 years old with documented issues. Per our Asset Management Program parameters recommended for replacement due to them having a high risk of being unable to provide reliable service or experiencing catastrophic failure. As discussed previously, the asset management evaluation process utilizes a data-based analysis to arrive at this outcome.

Both the Weatherby and Blue Valley Transformers were replaced due to being a dual LTC design. As discussed above in my "Replacing Rather than Rebuilding" testimony, dual LTC transformers are subject to substantially higher mechanical forces than standard transformer designs due to their additional windings and switching components, increasing the risk of winding movement, distortion of clamping structures, and long-term equipment degradation. These issues have shown that these transformers are prone to unpredictable catastrophic failures that can lead to extended customer impacts. This system risk and safety concern for catastrophic failure is the justification for replacement of these transformers.

D. Replacing Circuit Breakers Without Adequate Justification

Q. Mr. Shapley recommends disallowance of two breaker replacement projects – one project with six breakers not older than 19 years and one project with two switchgears 23 and 31 years old. What is Evergy's justification for replacing these breakers/switchgears at these ages?

A. All of the breakers noted by Mr. Shapley for disallowance are switchgear breakers and were replaced as part of broader switchgear replacement project. The first switchgear replacement was Forest Substation Switchgear #3 for $2.7M - Mr. Shapley noted this as six breakers with none being more than 19 years old. The second switchgear replacement was Gladstone Substation Switchgear #1 for $2.4M with breakers of 31 and 23 years old.

Additional background information beyond what was requested in the original data request is that both of the switchgears were in excess of 50 years old. In the 1990s and 2000s, the original hydraulic breakers were failing and causing reliability issues in both of these switchgears. To extend the life of the switchgear, the original hydraulic breakers were removed, and spring breakers were retrofitted into the switchgear. All other components of the switchgear remained intact. Now that the switchgears have experienced 50+ years of continuous service, other issues have developed that could only be addressed by replacing the switchgears. Issues include deteriorating metal enclosures, water intrusion, internal insulation failures causing main bus shorting, and other concerns with the asset remaining electrically sound. Due to these more extensive issues beyond what was addressed during the original life extension, the prudent action was to replace the switchgears which encompasses breaker replacements. When the switchgears were taken out of service, any breakers that were functionally acceptable were retained as spares to be used as replacements with other in-service retrofitted switchgears.

Q. Please provide a brief summary of your rebuttal testimony.

A. EMM's substation investments decisions were based on prudent, condition-based asset management practices that are widely recognized throughout the utility industry. The recommendations of OPC witnesses rely heavily on assumptions that equipment should remain in service until failure or objective test results require replacement. EMM evaluates asset condition, reliability risk, safety, concerns, maintenance history, operational requirements, and long-term lifecycle considerations when making replacement and investment decisions. My testimony shows the transformer switchgear, and spare equipment investments challenged by OPC were reasonable and necessary to maintain reliable electric service and manage risk for customers. The Commission should dismiss the recommended disallowances from OPC and the Staff's criticisms of early retirement of assets.

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 Rebuttal Testimony on behalf of Evergy Missouri West consisting of twenty-three (23) 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

Andrew Rietcheck

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

Anthy R

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