BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri 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**

STAFF'S INITIAL POST-HEARING BRIEF

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** Denotes Confidential Information **

*** Denotes Highly Confidential Information ***

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COMES NOW Staff of the Missouri Public Service Commission ("Staff"), by and through undersigned counsel, and for its *Post-Hearing Brief* states as follows:

INTRODUCTION

In this general rate case, the Commission must exercise its delegated authority to set prospective rates for Evergy Missouri Metro, Inc., d/b/a Every Missouri Metro ("EMM") a task that involves balancing the interests of ratepayers, the utility, and a myriad of other intervening parties with disparate interests and differing ideas about the issues and policies presented. The Commission must weigh the evidence presented before it to come to its ultimate goal in setting rates that are "just and reasonable," which is a rate that provides sufficient revenue to cover EMM's costs in providing electric service, allows EMM shareholders a reasonable opportunity to earn a fair return on their investment, but is no more than necessary to meet those goals, which protects the rate-paying residents and businesses EMM serves.[1]

[1] Mo. Rev. Stat. § 393.130 and § 393.140.

The parties in this case include EMM, Staff, The Office of the Public Counsel ("OPC"), Renew Missouri Advocates d/b/a Renew Missouri ("Renew"), Midwest Energy Consumers Group ("MECG"), Google LLC ("Google"), Velvet Tech Services, LLC ("Velvet Tech"), and Missouri Industrial Energy Consumers ("MIEC").[2]

Tracy D. Johnson

LEGAL STANDARD

Each proceeding for fixing of rates of a public utility company must be determined upon its own facts. The rate of return for a public utility is determined by a calculation that factors in: (1) the ratio of debt and equity to total capital; and (2) the cost and (3) weighted cost for each of these capital components.[3]

The Commission has authority under Chapters 386 and 393, RSMo, to regulate public utility rates and to ensure rates are "just and reasonable"[4] after considering all relevant factors.[5] EMM is a public utility, and an electric corporation, as those terms are defined in Section 386.020(15) and (43), RSMo. As such, EMM is subject to the jurisdiction of the Commission pursuant to Chapters 386 and 393, RSMo.

The United States Supreme Court in the *Hope* case established that the rate making process involves a balancing of the investor and consumer interests.[6] It also established in

[2] Velvet Tech and MIEC did not take a position on any issues in the case but reserved the right to do so.
[3] 20 CSR 4240-13.015(1)(C): Billing period means a normal usage period of not less than twenty-six (26) nor more than thirty-five (35) days for a monthly billed customer nor more than one hundred (100) days for a quarterly billed customer, except for initial, corrected, or final bills.
[4] Mo. Rev. Stat. § 393.130 and § 393.140.
[5] *State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission*, 585 S.W.2d 41, 49 (Mo. banc. 1979). ("the commission must of course consider all relevant factors including all operating expenses and the utility's rate of return").
[6] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

the *Bluefield* case, that a public utility is entitled to rates that allow a return on the value of its property comparable to returns on investments of similar risks, that is sufficient to assure confidence in the utility's financial soundness and to maintain credit.[7] Missouri courts have upheld that principle in their rulings, balancing the interests of the stakeholders with the public interest.[8] Further, The opinion of a qualified expert may amount to substantial and competent evidence for the purposes of arriving at a conclusion in a case.[9]

The property upon which a rate of return can be earned must be utilized to provide service to its customers. That is, it must be used and useful. This used and useful concept provides a well-defined standard for determining what properties of a utility can be included in rate base.[10] EMM has the burden of proving that its proposed increase is just and reasonable.[11] A "just and reasonable" rate is one that balances the interests of the various parties in a manner that best benefits overall public interest.[12] A just and reasonable rate is fair to both the utility and to its customers[13] and is no more than is necessary to "keep public utility plants in proper repair for effective public service, [and] . . . to insure to the investors a reasonable return upon funds invested."[14]

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[7] *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Commission of West Virginia*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923).
[8] *State ex rel. Union Electric Co. v. Public Service Commission*, 765 S.W.2d 618, 622 (Mo. App. W.D. 1988).
[9] *State ex rel. General Tel. Co. of Midwest v. Public Service Commission*, 537 S.W.2d 655, 663 (Mo. App. W.D. 1976).
[10] *In Re Missouri Gas Energy*, 256 P.U.R.4th 250 (Mar. 22, 2007).
[11] § 393.150.2, RSMo.
[12] *See State ex rel. Union Electric Co. v. Public Service Commission,* 765 S.W.2d 618, 622 (Mo. App., W.D. 1988) ("Ratemaking is a balancing process").
[13] *St. ex rel. Valley Sewage Co. v. Public Service Commission,* 515 S.W.2d 845 (Mo. App., K.C.D. 1974).
[14] *St. ex rel. Washington University et al. v. Public Service Commission,* 308 Mo. 328, 344-45, 272 S.W. 971, 973 (banc 1925).

The Commission sets just and reasonable rates via a two-step process using traditional cost-of-service ratemaking.[15] First, the "revenue requirement" must be determined, that is, the amount of income the utility needs on an annual basis.[16] This is determined by matching expenses, investments, and revenue,[17] and the relationship between the three is the fundamental building block of Missouri ratemaking.[18] This relationship is examined during the test year, and the Missouri Court of Appeals described the test year as follows:

> The test year is the primary mechanism through which the PSC determines appropriate rates. The PSC focuses on four factors during the test year: (1) the rate of return the utility has an opportunity to earn; (2) the rate base upon which a return may be earned; (3) the depreciation costs of plant and equipment; and (4) allowable operating expenses. These factors are considered to determine the utility's revenue requirement, which is the amount of revenue taxpayers must generate to pay the costs of producing the utility's services they receive while yielding a reasonable rate of return. The PSC's use of a true-up audit and hearing is designed to balance the historical data with known and measurable subsequent and future changes; these are generally limited only to accounts affected by a significant known and measurable change, such as a new labor contract, new tax rate, or the completion of a new capital asset. This procedure is designed to reduce regulatory lag.[19]

[15] *See* L.E. Alt, *Energy Utility Rate Setting,* 18 (2006).
[16] Edison Electric Institute (EEI), *Rate Shock Mitigation* (June, 2007) p. 5 ("In simple terms, a utility's cost of service or revenue requirement consists of three primary elements: (1) operating costs, such as fuel costs, purchased power costs, operations and maintenance (O&M) costs and customer service costs; (2) a return of capital cost, otherwise known as depreciation expense; and (3) a return on capital cost, including applicable income taxes.").
[17] Ex. 215, Rebuttal Testimony of Karen Lyons, p. 19, ll. 18-19.
[18] *See State ex rel. GTE N., Inc. v. Missouri Pub. Serv. Comm'n,* 835 S.W.2d 356, 368 (Mo. Ct. App. 1992).
[19] *In Matter of Kansas City Power & Light Co.'s Request for Auth. to Implement a Gen. Rate Increase for Elec. Serv. v. Missouri Pub. Serv. Comm'n*, No. WD 79125, 2016 WL 4626933, at *5 (Mo. Ct. App. Sept. 6, 2016), *reh'g and/or transfer denied* (Nov. 1, 2016), *transfer denied* (Feb. 28, 2017).

Second, after the revenue requirement is determined, rates must be designed in a manner that, given the usage characteristics of the utility's customers, will produce the necessary revenue, with no class significantly under- or over-contributing to the overall revenue produced.[20] Fair rates match costs and cost causers, so that similarly situated customers pay the same rates. Appropriate rate design is shaped in the context of a class cost of service study. From there, interclass revenue responsibility shifts, as applicable, are designed to bring each class closer to producing the system-average rate of return used in determining the recommended revenue requirement. A well-designed CCOS[21] will produce rates that are non-discriminatory and based upon principles of cost causation. That is not to say that that rates or rate increases must be the same for each class, as "discrimination as to rates is not unlawful where based upon a reasonable classification corresponding to actual differences in the situation of the consumers or the furnishing of the service."[22]

Additionally, rate design may include considerations beyond recovering the necessary revenue requirement. These objectives may be fairness, simplicity, stability, avoidance of undue discrimination or preferences, efficiency, and conservation.[23] Avoidance of rate shock and affordability concerns are also top-of-mind across the industry.

Parties may file a stipulation and agreement as a proposed resolution to all or part of the contested case. The Commission may resolve all or part of a contested case on the basis

[20] *See State ex rel. Missouri Office of Pub. Counsel v. Pub. Serv. Comm'n of State*, 293 S.W.3d 63, 73 (Mo. Ct. App. 2009).
[21] Class Cost of Service (CCOS).
[22] *Smith v. Pub. Serv. Comm'n*, 351 S.W.2d 768, 771 (Mo. 1961).
[23] Alt, *supra,* 58-60; J.C. Bonbright *et al., Principles of Public Utility Rates,* 85-179 (PUR: Arlington, VA, 2nd ed. 1988).

of a stipulation and agreement.[24] If a party chooses to object to all or part of a stipulation and agreement, the stipulation shifts procedurally from being a settlement to the signatory parties stipulated position. As a stipulated position, parties are not bound by the stipulation and may provide additional support of its stipulated position in the evidentiary hearing.[25] Any objecting parties must identify specific provisions within the stipulation objected to and must provide justification for each objection. Failing to satisfy the regulations' objection requirement within seven (7) days in accordance with the Commission rule constitutes a waiver.[26]

Although six stipulations have been filed, none have been approved in part or in whole. The Commission is left with a tremendous amount of decisions to make, which will impact both the overall revenue requirement and rate design. When determining the appropriate resolution for all issues, those never addressed in a stipulation or those pulled out of a stipulation by choice of the Commission, the guiding principles of ratemaking are still the foundation for decisions. In summary, Staff urges the Commission to set just and reasonable rates for EMM, after due consideration of all relevant factors, by adopting Staff's recommendations as discussed herein.

Tracy D. Johnson

[24] *State ex rel. Monsanto Co. v. Public Service Commission of Missouri*, 716 S.W.2d 791 (Mo. banc. 1986).
[25] 20 CSR 4240-2.115(2)(D).
[26] 20 CSR 4240-2.115(2)(B) states that the objecting party shall identify the specific provision of the stipulation and agreement that is objected to and provide a reason for each objection. Failure to file a timely objection shall constitute a full waiver of that party's right to a hearing.

STIPULATIONS

Summary:

Between October 2, 2026, and October 7, 2026, six partial non-unanimous stipulations were filed in this case. Attachment A, incorporated hereto by reference, provides an outline of which issues are addressed by each stipulation in the same order they are laid out below in an attempt to provide readers with a quick reference across the agreements.

I. Auditing Stipulation: Signed by EMM and Staff. Not opposed by OPC, Renew, or Google. MECG opposed for the limited purpose of preserving (in part) Issue 17 A *Depreciation – Which depreciation rates should be used?*[27]

II. OPEB Stipulation: Signed by EMM and Staff.[28] Not opposed by OPC, Renew, Google, or MECG.

III. Non-C&I Stipulation: Signed by EMM and Staff.[29] Not opposed by OPC, Renew, Google, or MECG.

IV. Programs Stipulation: Signed by EMM, Staff and Renew. Not opposed by Google or MECG. OPC opposed (in part) specifically to Issue 16 E *Income-Eligible Programs – Should the Commission approve the creation of a low-income rate or assistance program that waives EMM's customer charge for qualifying customers in this case, or should such a program continue to be developed in*

[27] EFIS Item No. 311 *Partial Stipulation and Agreement* (Stipulation I).
[28] EFIS Item No. 310 *Non-Unanimous Stipulation and Agreement Regarding Pensions and Other Post-Employment Benefits* (OPEB) (Stipulation II).
[29] EFIS Item No. 312 *Partial Stipulation and Agreement - Non-C&I Rate Design* (Stipulation III).

the Affordability Workshop? – i. If such a program is approved, should late fees be waived for qualifying customers? – ii. If such program is approved, how should the waived revenues be recovered?[30]

V. LLPS Stipulation: Signed by EMM and Google.[31] Opposed by Staff[32] and OPC[33]. Opposed by MECG for the limited purpose of preserving the right to take a position on the issues included within its post-hearing briefs.[34] Renew remained silent in response to this stip.

VI. Rate Design Stipulation: Signed by EMM and MECG.[35] Google does not oppose. Opposed by Staff[36] and OPC.[37] Renew remained silent in response to this stip.

Tracy D. Johnson

Stipulation I (Auditing) and Stipulation II (OPEB):

On October 2, 2026, EMM and Staff filed a *Partial Stipulation and Agreement*, which also indicated that OPC, Renew Missouri, and Google did not oppose Commission approval of the agreement ("Stipulation I").[38] Stipulation I further states that "MECG does not oppose the agreement except that Brian Andrew's life estimate adjustments are

[30] EFIS Item No. 320 *Non-Unanimous Programs Stipulation and Agreement* (Stipulation IV).
[31] EFIS Item No. 314 (Highly Confidential) and 317 (Public) *LLPS Partial Stipulation and Agreement* (Stipulation V).
[32] EFIS Item No. 318 *Staff Objection to LLPS Partial Stipulation and Agreement* (Public and Highly Confidential).
[33] EFIS Item No. 324 *Public Counsel's Opposition to LLPS Settlement* (Public and Highly Confidential).
[34] EFIS Item No. 325 *MECG Response to Commission's Order Shortening Time to Object to Stipulation and Agreements*.
[35] EFIS Item No. 313 *Non-Unanimous Partial Settlement - Rate Design* (Stipulation VI).
[36] EFIS Item No. 322 *Staff Objection to Non-Unanimous Partial Settlement - Rate Design*.
[37] EFIS Item No. 323 *Public Counsel's Opposition to Non-Unanimous Partial Settlement - Rate Design*.
[38] Case No. ER-2026-0143, EFIS Item No. 311, Stipulation I, p. 1.

preserved for hearing."[39] More specifically, Issue 17(A) concerning depreciation rates was in part preserved for MECG at hearing.[40] No other Party filed an objection to Stipulation I.[41] Pursuant to Commission's rules, "[a] party may indicate that it does not oppose all or part of a nonunanimous stipulation and agreement" and "[a] nonunanimous stipulation and agreement to which a timely objection has been field shall be considered to be merely a position of the signatory parties to the stipulation position, except that no party shall be bound by it."[42] Stipulation I also contains certain general provisions, including that signatories to Stipulation I "shall not be prejudiced, bound by, or in any way affected by the terms of this Agreement … (c) in these proceedings should the Commission decide not to approve this Agreement, or in any way condition its approval of same"[43] and that "[i]f the Commission does not approve this Agreement unconditionally and without modification, then this Agreement shall be void and no Signatory shall be bound by any of the agreements or provisions hereof."[44]

Staff recommends that the Commission approve Stipulation I. Stipulation I resolves the issues identified in Attachment A. Paragraph 1 of Stipulation I provides that "[t]he Signatories agree to the following terms as set forth below in exchange for a $46 million increase in Staff's revenue requirement filed with the true-up rebuttal testimony with consideration to the revenue requirement ordered by the Commission for issues not

[39] *Id*.
[40] *Id.*; *see also* Case No. ER-2026-0143, EFIS Item No. 325, *MECG Response to Commission's Order Shortening Time to Object to Stipulation and Agreements*, p. 2.
[41] Staff and OPC separately filed objections to Stipulation V and Stipulation VI. *See* Case No. ER-2026-0143, EFIS Item Nos. 318, 322, 323, and 324.
[42] 20 CSR 4240-2.115(2)(B) and (D).
[43] Stipulation I, p. 16, paragraph 30.
[44] Stipulation I, p. 16, paragraph 31.

settled" in Stipulation I.[45] Additionally, Paragraph 13 of Stipulation I addresses Pensions and OPEBs and states that "[a] separate Stipulation and Agreement which establishes the level of recovery will be filed."[46] A *Non-Unanimous Stipulation and Agreement Regarding Pensions and Other Post-Employment Benefits* was filed on October 2, 2026 ("Stipulation II").[47]

Staff recommends that the Commission approve Stipulation I and Stipulation II. However, should the Commission decline to approve Stipulation I or Stipulation II, then Staff argues in the alternative that the Commission should rely on Staff's position statements, filed on September 25, 2026,[48] relating to the issues identified in Attachment A under Stipulation I and II.

Alexandra Klaus

Staff's positions regarding Revenues and Billing Determinants, Issues 2.A – 2.A.xii, were agreed to by EMM and not opposed by other parties. Select nuance related to Staff's position on these issues is discussed below for the Commission's consideration.

Regarding Issue 2.A.ii, Staff's Proposed Rate Switcher and Large Power Service ("LPS") Customer Annualization Adjustment. In order to adjust for two customers switching from the LPS rate class to the Large General Service ("LGS") rate class during the update period, Staff removed these two customers' billing determinants and revenue from the LPS

[45] Stipulation I, p. 1, paragraph 1.
[46] Stipulation I, p. 5, paragraph 13.
[47] Case No. ER-2026-0143, EFIS Item No. 310. Stipulation II allows EMM to utilize Generally Accepted Accounting Principles (GAAP) method for regulatory purposes to simplify these calculations. It also sets forth the appropriate related tracker mechanism for pension and OPEB expenses and addresses details related to calculations of annual pension cost and annual OPEB cost, among other items.
[48] EFIS Item No. 295, *Staff's Statement of Positions* (Public, Confidential and Highly Confidential).

rate class and "added them to the LGS rate class."[49] Staff's recommended LPS annualization adjustment is $3,351,579 and 46,752,914 kWh.[50] Staff's LPS annualization adjustment reflects two changes which occurred during the true-up period. These two changes were: 1). annualizing a new customer who entered the LPS rate class during the true-up period; and 2). updating Customer B's annualization.[51] Staff annualized the new customer to reflect a year's worth of usage. During the true-up period, Customer B grew. Based on Customer B's growth, Staff updated Customer B's annualization to "reflect the most recent months of data."[52]

Regarding Issue 2.A.xii, Staff Recommends the Commission Adopt Staff's Rate Revenue Adjustments and Billing Determinants for Large Power Service ("LPS") Customers as part of Stipulation I or on their own as Staff's original position. These adjustments and determinants are located in Schedule AR-td1 of Staff Witness Amanda Rucker's True-Up Direct testimony.[53]

Staff and EMM have divergent views with regard to the retail rate revenues of Customer B. As mentioned above, during the true-up period, Customer B grew. Based on Customer B's growth, Staff updated Customer B's annualization to "reflect the most recent months of data."[54] EMM, on the other hand, simply normalized Customer B's billing determinants.[55] Normalization is proper when accounting "for unusual and unlikely events

[49] Direct Testimony of Amanda Rucker, page 3, lines 15-18.
[50] True-Up Direct Testimony of Amanda Rucker, page 3, lines 1-4.
[51] True-Up Direct Testimony of Amanda Rucker, page 1, line 16 – page 2, line 3.
[52] True-Up Direct Testimony of Amanda Rucker, page 1, line 16 – page 2, line 3.
[53] True-Up Direct Testimony of Amanda Rucker, pg. 3, footnote 5.
[54] True-Up Direct Testimony of Amanda Rucker, page 1, line 16 – page 2, line 3.
[55] True-Up Rebuttal Testimony of Amanda Rucker, page 1, line 17 – page 2, line 9.

that would not be repeated in years when the new rates from this case are in effect."[56] This differs from annualization adjustments, because annualization adjustments "reflect known conditions at the end of the period evaluated."[57]

It is proper in this case to apply an annualization adjustment to Customer B because it accounts for Customer B's growth up from the LGS rate class to the LPS rate class.[58] Moreover, Staff's use of Customer B's billing determinants "during the last several months of the true-up period to annualize billing determinants that occurred in the earlier months, Staff's annualization accounts for a year's worth of information to be reflected closer to the known conditions at the end of the true-up period."[59]

Andrea B. Hansen

Stipulation III (Non-C&I):

Stipulation III resolves Issues 2.A.xiii and xiv, along with 28A and 29C. This agreement includes Staff's True-Up Economic Development Rider discount annualization, keeps the residential customer charge at $12.00, holds the Residential Peak Adjustment unchanged, and equally applies the rate increase across all other residential billing components.[60] Additional tariff sheet updates are included, most notably a Minimum Demand provision is added to the Standby Service Rider.[61]

[56] True-Up Rebuttal Testimony of Amanda Rucker, page 2, lines 11-13.
[57] True-Up Rebuttal Testimony of Amanda Rucker, page 2, lines 13-14.
[58] True-Up Rebuttal Testimony of Amanda Rucker, page 2, lines 17-19.
[59] True-Up Rebuttal Testimony of Amanda Rucker, page 2, line 19 – page 3, line 2.
[60] Stipulation III, p. 1-2
[61] Stipulation III, p. 4

Staff recommends that the Commission approve Stipulation III. However, should the Commission decline to approve Stipulation III, then Staff argues in the alternative that the Commission should rely on Staff's position statements, filed on September 25, 2026,[62] relating to the issues identified in Attachment A under Stipulation III.

Tracy D. Johnson

Staff's position regarding the Minimum Demand provision for Standby Service Rates, Issue 29.C, were agreed to by EMM and not opposed by other parties. Issue 29.C is also mentioned in Stipulation VI between EMM and MECG, but only so far as they agree to the resolution of the issue as laid out by Staff and EMM in Stipulation III. There is no conflict between the two stipulations on the issue. Further, If the Commission chooses not to adopt Stipulation III, Staff recommends the following for rate schedules to be effective on November 1, 2027:

> Alignment of paragraph 11, "Standby Service Demand," with the 15-minute demands, demand bright lines, and peak demand periods established for the SGS, MGS, LGS, and LPS restructured schedules.[63]

And

> Alignment of the rates for service structures and rates with those established 4 for the SGS, MGS, LGS, and LPS restructured schedules.[64]

Andrea B. Hansen

[62] EFIS Item No. 295, *Staff's Statement of Positions* (Public, Confidential and Highly Confidential).
[63] Staff Rate Design Report, pg. 27, lines 1-3.
[64] Staff Rate Design Report, pg. 27, lines 4-5.

Stipulation IV (Programs):

Stipulation IV resolves Issues 16 and 38 through 41. Stipulation IV increases funding for EMM's Economic Relief Program (ERP) to $1,410,000 and removes the pilot designation; increases funding for EMM's Critical Medical Needs Program to $600,000, shared 50/50 between ratepayers and shareholders; increases funding for the Income-Eligible Weatherization Program to $750,000, shared 50/50 between ratepayers and shareholders; requires EMM to provide an annual summary of program administration and reporting and evaluation for the Rehousing Program; removes the Third Party Energy Burden tool development request and reallocates the $150,000 to the ERP; accepts proposed tariff revisions for rehousing and ERP programs; increases Staff's revenue requirement to reflect program increases; requires EMM to implement the Green Button Connect (GBC) My Data by December 31, 2026; requires EMM to convene a stakeholder meeting on or before the fourth quarter of 2027 to discuss the potential development of a battery storage program; and requires EMM to continue operating its existing Income Eligible Solar Subscription Pilot under its approved terms.[65]

Ray Cunneen

Regarding Issue 38.A, *Energy Burden Analysis: Should the Commission order a 3rd party energy burden analysis for Evergy Metro that does not exceed $150K in costs?* Staff takes no position on this issue, except to the extent it is addressed by Stipulation IV in this case.

Tracy D. Johnson

[65] Stipulation IV, p. 1-3.

Regarding Issue 39, Subpart A, Stipulation IV requires GBC My Data by December 31, 2028, for all customer classes, compliance with Green Button standards, convenient and secure authorization following GBC best practices, and annual Green Button Alliance certification. It permits deferral of set-up, implementation, and licensing costs for consideration in the next general rate case. Staff therefore recommends the joint position in Stipulation IV.

If the Commission does not adopt Stipulation IV, Staff recommends against Renew Missouri's pre-stipulation implementation proposal. The potential customer benefits warrant consideration, but the implementation decision must also account for the systems, costs, and safeguards needed to provide the service. Staff witness Shawn E. Lange, PE recognized GBC's significant potential customer benefits.[66] He nevertheless identified the need for "additional information about the implementation costs, operations and maintenance costs, and any potential privacy safeguards related to GBC."[67]

Renew Missouri witness Katherine Wyszkowski addressed security, privacy, and breach-notification requirements and her proposed DataGuard privacy obligation.[68] She also pointed to EMM's vendor estimate as a more direct cost basis.[69] However, EMM's expert Ms. McDonald described estimates for Kansas and Missouri implementation and three years of licensing that excluded internal implementation, operation, maintenance,

[66] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 6, at line 4-12.
[67] *Id.*, p. 7, at line 1-11.
[68] Katherine Wyszkowski, Surrebuttal Testimony, EFIS Item No. 237, p. 12, at line 9-14.
[69] *Id.*, p. 12, line 15-18.

and administration costs.[70] The vendor estimate therefore cannot, by itself, satisfy the GBC full cost concern.

Regarding Issue 39, subpart B, If the Commission does not adopt Stipulation IV and orders implementation, Staff recommends declining to adopt Renew Missouri's proposed tariff at this time and rejecting its Termination provision in its entirety. Mr. Lange warned that "potential risks may be left unaddressed" during a Commission investigation and hearing.[71] The Termination provision does not expressly provide for temporary protective measures to address cybersecurity risks.[72] Before considering tariff language, the Commission should require EMM to complete the system assessment Mr. Lange recommended in Staff's initial position on this issue.[73]

Regarding Issue 39, subpart C, Staff recommends that the Commission adopt the cost treatment in paragraph 6 of Stipulation IV: deferral of set-up, implementation, and licensing costs for consideration in EMM's next general rate case.[74] The initial estimates provided combine upfront and ongoing costs.[75] The vendor estimates cover implementation in Kansas and Missouri and three years of licensing but exclude internal costs.[76] Those figures still require allocation among jurisdictions and separate treatment of one-time and recurring costs before they can support an annual revenue requirement for EMM.[77]

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[70] Katie R. McDonald, Rebuttal Testimony, EFIS Item No. 191, p. 5, at line 14-22.
[71] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 8, at line 11-17.
[72] Appendix A, Katherine Wyszkowski, proposed Green Button Connect tariff, EFIS Item No. 128, p. 5, paragraph (f)(4). See also Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 8, at line 5-10 (quoting the Termination provision).
[73] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 7, at line 12-18.
[74] Non-Unanimous Programs Stipulation and Agreement, EFIS, Item No. 320, p. 2, paragraph 6.
[75] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 8, at line 21-23; p. 9, at line 1-12.
[76] Katie R. McDonald, Rebuttal Testimony, EFIS Item No. 191, p. 5, at line 14-23; p. 6, at line 1.
[77] Katie R. McDonald, Rebuttal Testimony, EFIS Item No. 191, p. 5, at line 19-23; p. 6, at line 1; Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 8, at line 21-23; p. 9, at line 1-12.

If the Commission does not adopt Stipulation IV and orders implementation, Staff recommends rejecting the proposed current allowance and suggests the Commission determine the revenue requirement in a future rate case after the upgrades are complete and serving customers, at a time when the completed upgrades and associated costs can be reviewed together.[78]

Regarding Issue 39, subpart D, Staff recommends that the Commission adopt the joint position in paragraph 6 of Stipulation IV. That provision addresses deferral of GBC setup, implementation, and licensing costs without a separate current allowance for a regional data-hub study.[79] If the Commission does not adopt the joint resolution but orders implementation, Staff recommends rejecting the proposed $100,000 study allowance. Potential economies of scale support considering regional cooperation, but they do not, by themselves, justify charging EMM's customers $100,000 for the study.[80] The proposal involves utilities with different technologies, vendors, and implementation schedules. Developing a regional platform would also require coordination on governance, operations, and cost allocation.[81] Those considerations affect both the study's scope and who should pay for it. The Commission should require support for the proposed expense and EMM's appropriate share rather than infer either from the potential benefits of a regional platform.[82]

Staff supports the GBC position offered by Stipulation IV because it sets an implementation deadline and service requirements while reserving cost recovery for later

[78] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 8, at line 19-21.
[79] Non-Unanimous Programs Stipulation and Agreement, EFIS Item 320, p. 2, paragraph 7.
[80] Wyszkowski Direct, EFIS Item No. 120, p. 27, at line 6-21; p. 28, at line 1-2.
[81] McDonald Rebuttal, EFIS Item No. 191, p. 7, at line 20-23; p. 8, at line 1-6.
[82] *Id.*, p. 9, at line 1-3.

consideration when more complete and accurate information is available. If the Commission does not adopt Stipulation IV, Staff recommends obtaining the additional cost and privacy information Mr. Lange identified before requiring implementation under the earlier proposal put forward by Renew.[83]

Regarding Issue 40. Customer Battery Programs, Staff recommends that the Commission adopt the joint position in paragraph 7 of Stipulation IV. It provides for no pilots in this proceeding and calls for a stakeholder meeting on or before the fourth quarter of 2027, preceded by customer-interest survey results and specified circuit and system information.[84]

If the Commission does not adopt the stipulation and orders EMM to propose customer battery pilot programs in its next general rate case, Staff recommends safeguards for those proposals.[85] Each proposal should include a cost-benefit analysis, clear learning objectives and evaluation criteria, eligibility for all EMM customers except employees, contractors, directors, agents, and employees of affiliates, a defined cost cap, separate accounting, semiannual reporting, and an end date or transition plan.[86] These conditions would help the Commission evaluate the program and protect non-subscribers before considering a permanent program.

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[83] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 7, at line 1-11.
[84] Non-Unanimous Programs Stipulation and Agreement, EFIS Item No. 320, p. 2-3, paragraph 7.
[85] Shawn E. Lange, PE, Rebuttal Testimony, EFIS Item No. 164, p. 3, at line 6-21; p. 4, at line 3-22.
[86] *Id*., p. 3, at line 14-18; p. 4, at line 7-19, 20-22.

Regarding Issue 41.A, *Income-Eligible Solar Program: Should the Commission order the adoption of Renew Missouri's proposed evaluation and expansion of the Income-Eligible solar program?* Staff takes no position on this issue, except to the extent it is addressed by Stipulation IV in this case.

Tracy D. Johnson

Conclusions In Support of Rejecting Stipulations V (LLPS) and Stipulation VI (LLPS):

Staff and OPC timely filed objections to Stipulation V and Stipulation VI. Pursuant to Commission rule, the objections allow the Commission to treat the stipulations and the issues they attempt to settle as the signatory parties' position, retaining authority to decide remaining issues after the hearing. Stipulation V and Stipulation VI do not appropriately balance interests nor follow cost-causation principles, as detailed in the filed objections and laid out in more detail further below. Staff's positions regarding each of the issues addressed in Stipulations V and VI can also be found further below. The additional details and Staff's positions are organized by issue number in the *Remaining Issues* section. To that end, it is Staff's expert opinion that, Stipulation V and Stipulation VI include terms that run a high-probability risk of producing unjust and unreasonable outcomes. For the reasons stated above, Staff respectfully recommends the Commission reject Stipulations V and VI in their entirety. If the Commission adopts terms from Stipulation V or VI, Staff strongly urges the Commission to specifically modify the terms as identified in Staff's positions below.

Tracy D. Johnson

Conclusions In Support of Adopting Stipulations I-IV:

Stipulations I-IV listed above offer a resolution, in large part, to 33 of the 42 joint issues submitted by the parties on September 24, 2026.[87] Stipulations I-IV are not unanimous. However, all parties contributed to them, all stakeholders are represented and any objection is clearly carved out in an effort to indicate non-opposition of the resolutions proposed on the other issues in each stipulation. Stipulations I-IV include multiple provisions that benefit ratepayers and are the product of extensive negotiations among diverse parties, reflecting the signatories' attempt to recognize the merits of various viewpoints on the resolved issues. Staff modified its positions to support Stipulations I-IV because, in this record, they are the most just and reasonable outcome for EMM and its stakeholders. Stipulations I-IV provide balanced solutions to the issues addressed in a way that supports the Commission's ability to produce a just and reasonable resolution of this entire case.

Although Staff no longer supports its pre-stipulated positions on the issues addressed by Stipulations I-IV, as identified in Attachment A, if the Commission does not adopt these four stipulations, Staff submits the next-best outcome would be the adoption of Staff's original positions as filed on September 25, 2026,[88] specifically the additional modifications from those positions as detailed throughout the Stipulations section above.

For the reasons stated above, Staff respectfully recommends that the Commission adopt Stipulations I-IV in their entirety, without modification.

Tracy D. Johnson

[87] EFIS Item No. 288 *Joint List of Issues, Order of Opening Statements, Order of Cross-Examination, and Order of Issues and Witnesses*.
[88] EFIS Item No. 295 *Staff's Statement of Positions* (Public, Confidential and Highly Confidential).

REMAINING ISSUES

Issue 1. Cost of Capital

There are four sub-issues for the Commission's consideration regarding the cost of capital for EMM. Those issues are (A) EMM's appropriate capital structure for ratemaking; (B) EMM's cost of debt for determining its rate of return; (C) the appropriate return on common equity ("ROE") for determining EMM's rate of return ("ROR"); and (D) the appropriate ROR to use for ratemaking in this proceeding.

As explained more fully in this initial brief, the Commission should order the following Staff recommendations as the proper resolution for all four sub-issues listed above:

A. The most appropriate capital structure to use is EMM's actual regulated electric operation standalone capital structure as of June 30, 2026, composed of 52.19% common equity, and 47.81% long-term debt;[89]
B. Staff recommends an actual embedded cost of debt of 4.54% as of June 30, 2026;[90]
C. Staff recommends an authorized return on common equity of 9.73% in a range of reasonableness of 9.48% to 9.98%;[91] and
D. Staff recommends a rate of return of 7.25% in a range of reasonableness of 7.12% to 7.38%.[92]

Introduction

Pursuant to § 393.150.2, RSMo., EMM bears the burden of proving that its proposed increased rates are just and reasonable. "The burden of proof in its strict sense [is] . . . that

[89] Exhibit 165, Surrebuttal/True-Up Direct Testimony of Seoung Joun Won, PhD, Schedule SJW-TD-2.
[90] *Id*.
[91] *Id*.
[92] *Id*.

of establishing the affirmative of the ultimate issue, which never shifts throughout the trial but remains upon the party asserting it[.]"[93] This burden is typically comprised of two components: the burden of producing evidence, and the burden of persuasion.[94]

In fixing electric rates, the Commission may consider all relevant facts, with due regard to a reasonable average return on capital actually expended and appropriate provision for surplus and contingencies.[95] Those provisions require an assessment of the evidence as a whole; neither a utility's requested return nor a particular financial model supplies the answer by itself.

The constitutional standards likewise focus on the resulting rates. A utility's return should be commensurate with returns on investments presenting corresponding risks and sufficient to maintain financial integrity, credit, and access to capital. As stated in *Bluefield Waterworks*:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become

[93] *Been v. Jolly,* 247 S.W.2d 840, 854 (Mo. 1952).
[94] *Kinzenbaw v. Director of Revenue,* 62 S.W.3d 49, 53 (Mo. banc 2001).
[95] § 393.270.4, RSMo.

> too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[96]

Ratemaking balances investor and consumer interests, and the controlling consideration is the overall result rather than adherence to a particular formula.

> We held in ***Federal Power Commission v. Natural Gas Pipeline Co.,*** *supra,* that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' *Id.,* 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. *Id.,* 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. *Cf.* ***Los Angeles Gas & Electric Corp. v. Railroad Commission,*** 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; ***West Ohio Gas Co. v. Public Utilities Commission (No. 1),*** 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; ***West v. Chesapeake & Potomac Tel. Co.,*** 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.[97]

These standards support adequate compensation for the risks EMM actually bears. They do not require customers to fund a premium merely because EMM proposes one. As was outlined in *Hope Natural Gas*, ultimately a utility could not complain if the return which was allowed made it possible for the utility to operate successfully.[98]

Staff applies those standards through an integrated analysis of capital structure, embedded debt cost, market-based equity estimates, authorized-return evidence,

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[96] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692–93, 43 S.Ct. 675, 679 (1923).
[97] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 602-603, 64 S.Ct. 281, 287 - 288 (1944).
[98] *Id* at 566.

and EMM's relative risk.[99] The Commission should evaluate the capital components together because the financial risk associated with a particular equity return depends in part on the leverage to which that return is applied.

A. What is the appropriate capital structure to use for ratemaking in this proceeding?

The Commission should use EMM's actual capital structure of 52.19% common equity and 47.81% long-term debt for ratemaking in this proceeding rather than the actual capital structure of its parent company, Evergy, Inc. Staff witness Dr. Seoung Joun Won's true-up analysis identifies those percentages as EMM's actual June 30, 2026, capitalization.[100] EMM witness Geoffrey Ley expressly agrees with Staff's recommended percentages.[101]

Staff did not accept EMM's recorded capitalization without examining its financing relationship with Evergy, Inc. Dr. Won identified four grounds for using the subsidiary's own capital structure:

1. EMM does not obtain all its capital from Evergy, Inc.;
2. Evergy, Inc. does not guarantee EMM's securities;
3. Staff did not find double leverage in the financing history examined; and
4. The consolidated enterprise is not significantly diversified into nonutility operations.[102]

[99] Exhibit 120, Direct Testimony of Seoung Joun Won, PhD, p. 3, ll. 5-18 and pp. 8-9.
[100] Ex. 165, p. 62, ll. 2-7.
[101] Exhibit 53, Geoffrey Ley True-Up Rebuttal Testimony, p. 2, ll. 9-15.
[102] Ex. 165, pg. 62, ll. 8-18.

Those considerations support use of the capitalization associated with the utility whose rates the Commission is setting, not its parent company.

Separate credit ratings reinforce that conclusion. Staff reported Moody's and S&P's ratings of Baa1 and A- for EMM, compared with Baa2 and BBB+ for Evergy, Inc.[103] Staff also found that proceeds from Evergy, Inc.'s long-term debt issuances had not been used to infuse equity into EMM.[104] These findings provide a concrete basis for treating EMM's financing separately from the parent company's consolidated leverage.

The OPC, on the other hand, has not justified replacing EMM's capitalization with Evergy, Inc.'s leverage. OPC witness David Murray recommends 45% common equity and 55% long-term debt for rate base other than construction work in progress ("CWIP").[105] Staff's objection is substantive: that recommendation imports Evergy Inc.'s more leveraged consolidated financing into the operating utility's rates despite the evidence supporting EMM's standalone capitalization.[106]

The OPC's concern that holding companies allocate capital to achieve favorable ratemaking ratios warrants scrutiny, but it does not establish that every subsidiary equity balance should be disregarded. Staff acknowledges that Evergy, Inc. allocates capital among subsidiaries. That fact does not establish that consolidated holding-company capitalization is the appropriate measure for EMM.[107] Nor does a lower weighted return, standing alone, establish the more economical and sustainable financing arrangement.

[103] Ex. 120, pg. 43, ll. 1-2.
[104] *Id*, ll. 10-14.
[105] Exhibit 207, David Murray Surrebuttal Testimony, p. 8, ll. 12-22.
[106] Ex. 165, p. 54, ll. 1-19.
[107] Exhibit 145, Rebuttal Testimony of Seoung Joun Won, PhD, p. 55, ll. 5-9.

Dr. Won explains that additional leverage increases fixed obligations and can increase the utility's borrowing cost.[108]

The Commission need not adopt an absolute rule favoring either actual or consolidated capitalization. It should decide this case on the evidence before it. Here, the separate borrowing and credit evidence, the absence of identified double leverage, and the actual true-up balances support the 52.19% equity structure. OPC's proposal would replace those facts with a more leveraged proxy without a sufficient utility-specific reason to do so.

The OPC also proposes distinct treatment for CWIP if the Commission authorizes its inclusion in rate base. Mr. Murray's primary CWIP recommendation is a 5.08% pre-tax return calculated to produce approximately zero net present value difference between CWIP recovery and continued allowance for funds used during construction ("AFUDC") treatment. He separately offers alternatives based on current long-term borrowing yields or an AFUDC-related financing mix.[109] Those proposals should be distinguished from his 45% equity recommendation for other rate base.

The financing-mix alternative uses approximately 25.86% common equity, 51.59% short-term debt, and 22.56% long-term debt, coupled with a 9.25% ROE, 3.87% short-term debt cost, and 4.54% long-term debt cost.[110] Dr. Won identifies the resulting overall return under, per Mr. Murray's calculations, as approximately 5.41%.[111] That figure is distinct from

[108] Ex. 165, p. 54, ll. 13-19 and footnote 178.
[109] Ex. 207, Murray Surrebuttal and True-Up Direct, p. 7, ll. 1-27; p. 8, ll. 1-11.
[110] *Id*, p. 8, ll. 1-5; *see also* Schedule DM-S-2.
[111] Exhibit 174, True-Up Rebuttal Testimony of Seoung Joun Won, PhD, p. 3, ll. 1-7, referencing Ex. 207, Schedule DM-S-2.

both OPC's 5.08% pre-tax cost-neutrality proposal and the 6.16% pre-tax figure Mr. Murray reports for the financing-mix alternative.[112]

Staff opposes treating that temporary construction mix as EMM's permanent ratemaking capitalization. Short-term borrowing bridges the timing of investment and permanent financing; equity remains exposed to construction and enterprise risks during that period.[113] Dr. Won explains that a balanced long-term structure supports credit quality and continuing capital access, and that a temporary bridge-financing ratio does not measure the utility's ongoing cost of capital.[114]

The Commission should also distinguish the policy question of whether particular expenditures qualify for CWIP recovery from the financial question of what return appropriately compensates capital supporting any authorized investment. Selecting a return solely to reach a desired present-value comparison does not independently establish that the selected return meets EMM's financing requirements. Staff's position is conditional: if CWIP is authorized for cash recovery, the return should reflect the utility's actual cost of capital rather than a diluted short-term financing proxy.[115] This cost of capital recommendation does not, by itself, decide CWIP eligibility or allocation.

B. What cost of debt should be used for determining rate of return?

The Commission should adopt EMM's actual embedded long-term debt cost of 4.54% as of June 30, 2026; Dr. Won reports the underlying EMM figure as 4.541%, rounded

[112] Ex. 207, p. 8, ll. 8–11.
[113] Ex. 174, p. 4, ll. 1-20.
[114] *Id*., p. 5, ll. 4–19.
[115] *Id*., ll. 15–19.

to 4.54% for his recommendation.[116] Mr. Ley expressly agrees.[117] OPC likewise applies 4.54% to the long-term debt component in its final recommendation.[118]

The debt cost should match the entity and capital component being measured. Dr. Won reports Evergy Inc.'s embedded long-term debt cost as 5.353%, compared with EMM's 4.541%.[119] The parent's debt cost is not a substitute for the operating utility's actual embedded cost. Nor does an increase in current Treasury yields automatically reprice the outstanding debt portfolio. The appropriate determination on this record is the true-up embedded cost, paired with the 47.81% long-term debt weight that was addressed under sub-issue A.

C. What return on common equity should be used for determining rate of return?

The Commission should authorize a 9.73% return on common equity, within Staff's 9.48% to 9.98% reasonable range.[120] This recommendation is not an arithmetic compromise between EMM and OPC. It is the result of Staff's examination of market returns, authorized returns, and EMM's risk.

Staff uses the discounted cash flow ("DCF") and capital asset pricing model ("CAPM") analyses to estimate investors' market-based cost of equity and a bond-yield-plus-risk-premium ("BY+RP") analysis to estimate an authorized return. Dr. Won explains that the DCF and CAPM results serve as checks on the BY+RP recommendation.[121] The distinction matters: the Commission authorizes a return on book

[116] Ex. 165, p. 63, ll. 1-7.
[117] Ex. 53, p. 2, ll. 16-20.
[118] Ex. 207, p. 8, ll. 17-20.
[119] Ex. 165, p. 63, ll. 1-4.
[120] *Id*, p. 64, ll. 6-9.
[121] Ex. 120, pp. 8-9; p. 55, ll. 6-18.

investment, while stock-market models estimate returns required at market prices. Those measurements inform one another, but their numerical results need not be identical.[122]

The true-up analysis updates the evidence rather than simply carrying forward the direct recommendation. Staff's updated DCF estimates range from 7.07% to 9.44%, with a mean of 8.26%; updated CAPM estimates range from 7.75% to 10.41%, with a mean of 9.08%. Staff's BY+RP estimate remains 9.73%, within model results of 9.72% to 9.75%.[123] Dr. Won found no material change warranting revision of the recommendation.[124] The broader 9.48% to 9.98% recommended range should not be confused with the narrow spread of BY+RP point estimates.

Staff's BY+RP analysis relates authorized electric utility returns to A-rated and Baa-rated utility bond yields over 2014–2025. It estimates a risk premium that varies inversely with bond yields, rather than mechanically adding a fixed spread.[125] Thus, Staff considers both contemporaneous debt-market conditions and the compensation historically authorized for equity risk, while checking the outcome against market-based models.

I. EMM models do not establish that a 10.50% ROE is reasonable

EMM witness Ann E. Bulkley maintains a range of 10.25% to 11.25% and supports EMM's requested 10.50%.[126] Her updated DCF, CAPM, ECAPM, and risk-premium results

[122] Ex. 165, p. 4, ll. 7-22.
[123] Ex. 165, p. 63, ll. 8-15 and Table 5.
[124] *Id*., p. 64, ll. 1–9.
[125] Ex. 120, p. 55, ll. 14-18 and p. 56, ll. 3-12.
[126] Exhibit 8, Ann E. Bulkley Rebuttal Testimony of, p. 11, ll. 2-6.

are summarized in her Figure 2.[127] Multiple model outputs, however, are persuasive only to the extent their assumptions are reasonable. Repeating a growth or risk-premium assumption in different models does not independently validate it.

First, Staff identifies a mismatch between the perpetual horizon of a constant-growth DCF model and the three-to-five-year earnings forecasts used as perpetual growth assumptions.[128] Near-term utility growth may be substantial without continuing indefinitely. Staff's recalculation using revised growth assumptions and proxy screening reduced the median average-growth DCF estimate from 10.56% to 9.75%.[129] That sensitivity illustrates why the Commission should examine inputs rather than accept an output solely because it falls within a witness's proposed range.

Staff does not rely on an obsolete proxy-group objection. Ms. Bulkley's rebuttal removes NextEra and Dominion following their announced merger transaction.[130] That revision addresses their continued inclusion; it does not resolve Staff's separate objection to using short-horizon earnings forecasts as perpetual growth inputs.

Second, Staff challenges the magnitude of Ms. Bulkley's market risk premiums. Her direct CAPM analysis used a total market return of 13.53% and premiums of approximately 8.88% to 8.93%.[131] Staff found that her market-return calculation incorporated companies lacking dividend information and used short-horizon growth inputs in a constant-growth framework.[132] Staff's recalculation produced a 10.44% total market

[127] *Id*, p. 11.
[128] Ex. 145, p. 13, ll. 1-17.
[129] *Id*., p. 15, ll. 1–6.
[130] Ex. 8, Bulkley Rebuttal, p. 10, ll. 12-21.
[131] Ex. 145, p. 15, ll. 8-15.
[132] *Id*., p. 17, ll. 5–16.

return and premiums below 6% using her three risk-free rates.[133] These are material input disputes, not minor preferences about rounding.

The ECAPM does not cure those inputs. Staff found its results were driven by the same overstated market-return procedures and recommended little weight for those estimates.[134] The Commission should decline to treat elevated CAPM and ECAPM outputs derived from shared assumptions as separate proof that 10.50% is reasonable and/or necessary.

Finally, a longer historical regression is not inherently superior to one directed at more recent conditions. Dr. Won explains Staff's choice of the 2014–2025 period and its separate regressions for A-rated and Baa-rated utility bonds.[135] The Commission should assess those choices with the market-model checks and current risk evidence; no goodness-of-fit statistic alone decides the appropriate return.

II. EMM's "risk evidence" does not establish a need for a premium

EMM points to its capital program, nuclear operations, fuel adjustment clause, and recovery risks.[136] Those are relevant considerations. The question is whether they establish incremental risk requiring a 10.50% equity return after considering the protections and comparable utility risks already reflected in the analysis.

Dr. Won identifies Plant in Service Accounting ("PISA") as a material protection against regulatory lag and explains that large capital investment programs are not unique to

[133] *Id*., p. 18, ll. 1–3.
[134] Ex. 145, p. 22, ll. 1-5.
[135] Ex. 165, p. 52, ll. 1-18.
[136] Exhibit 50, Rebuttal Testimony of Geoffrey Ley, p. 9, ll. 1-14.

EMM.[137] Staff found no evidence of significantly greater risk requiring an upward ROE adjustment and noted Ms. Bulkley's assessment that regulatory risk and timely recovery were generally consistent with the proxy utilities.[138] Staff also explains that credit assessments already consider nuclear-related risks.[139] Credit ratings are not a complete substitute for equity-risk analysis, but they provide a useful check on claims of exceptional enterprise risk.

Google witness Dr. Carolyn Berry's evidence supplies an additional reason to evaluate large-load growth in both directions. Dr. Berry identifies the revenue, collateral, and termination protections in Schedule LLPS as stabilizing features and explains that large-load growth can support cash flow and capital attraction.[140] That testimony rebuts an assumption that data-center growth necessarily requires a higher authorized return.

Mr. Ley responds that investment scale, customer concentration, collateral collection, and actual regulatory outcomes remain concerns and that the rating agencies have maintained stable, rather than positive, outlooks.[141] Staff need not deny those risks to reject EMM's requested premium. A stable outlook does not establish that LLPS protections have no mitigating value, and the existence of financing demands does not quantify an additional equity return. On balance, the evidence supports Staff's measured 9.73% recommendation without assuming either that large-load growth is risk-free or that it justifies 10.50%.

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[137] Ex. 145, p. 34, ll. 11-17 and p. 35, ll. 1-15.
[138] *Id*., p. 36, ll. 1–6.
[139] *Id*., p. 36, ll. 10–18.
[140] Exhibit 450, Direct Testimony (Revenue Requirement) of Carolyn Berry, p. 6, ll. 7-20; p. 7, ll. 1-12; p. 8, ll. 1-11; p. 9, ll. 3-21.
[141] Ex. 50, p. 10, ll. 3-21; p. 11, ll. 1-6.

III. The latest market update does not bridge the gap to 10.50%

Ms. Bulkley's true-up rebuttal reports that the 30-year Treasury yield increased from 4.91% on June 30 to 5.36% on September 15, 2026.[142] The Commission should consider that evidence, but the magnitude of a change in Treasury yields does not establish an equal change in the utility's required equity return, much less establish EMM's requested 10.50%.

Ms. Bulkley's own update of Staff's analyses is instructive. Using August data, she reports a DCF mean of 8.33%, a CAPM mean of 9.21%, and a BY+RP estimate of 9.75%.[143] She acknowledges that the BY+RP update increases Staff's result by only two basis points and that she did not fully update its historical regression.[144] Staff does not characterize her exercise as a complete re-estimation or an endorsement of Staff's recommendation. It does show that the later data, when applied in that exercise, do not produce an authorized-return estimate near 10.50%. The reported 9.75% remains within Staff's range and very close to its 9.73% recommendation.

IV. OPC's criticism of Ms. Bulkley does not establish that a 9.25% ROE is reasonable

Mr. Murray maintains a 9.25% ROE and criticizes Staff's reliance on prior authorized returns as circular.[145] Staff recognizes the analytical limitation: a regression using past authorized returns is not independent proof of investors' present required return. That is why Staff also estimates market-based returns and evaluates current conditions and relative risk.[146]

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[142] Exhibit 11, Ann E. Bulkley True-Up Rebuttal Testimony, p. 2, ll. 14-17.
[143] *Id*., p. 6, Figure 1.
[144] *Id*., p. 5, ll. 5–15.
[145] Ex. 165, p. 56, ll. 1–10.
[146] Ex. 120, pp. 8-9; *see also* Ex. 165, p. 63, Table 5.

Mr. Murray's objection therefore does not dispose of Staff's complete analysis. Nor does the historical observation that authorized returns changed less than bond yields establish the amount by which the Commission should reduce today's return. Dr. Won explains that equity premiums and other determinants can offset interest-rate changes, and that historical authorized-return behavior does not independently establish the level of market cost of equity.[147] The Commission should use Staff's 9.73% recommendation because the combined evidence supports it, rather than select 9.25% solely because it also exceeds some market-model results.

Authorized-return comparisons provide a reasonableness check, not a controlling national percentage. Dr. Won reports 2026 averages of 9.83% for electric utilities and 9.85% for vertically integrated electric utilities, both within Staff's recommended range.[148] Staff's 9.73% recommendation is reasonably situated against those comparators, while EMM's 10.50% request requires a stronger showing of incremental risk or financing need than that currently in the record.

Staff also notes that S&P currently assigns EMM an issuer credit rating of 'A-," which is one notch above the 'BBB+' rating commonly observed among U.S. electric utilities.[149] This would seem to indicate that EMM has lower credit risk than the average U.S. electric utility.

[147] Ex. 165, p. 57, ll. 20-29 and p. 58, ll. 10-16.
[148] *Id*, p. 3, ll. 3-13.
[149] *Id*, p. 8, ll. 3-5.

D. What is the appropriate rate of return to use for ratemaking in this proceeding?

The appropriate overall return is 7.25%, within a reasonable range of 7.12% to 7.38%. Dr. Won's final recommendation combines 52.19% common equity at 9.73% with 47.81% long-term debt at 4.54%.[150]

Component	Capital weight	Component cost	Weighted return
Common equity	52.19%	9.73%	5.0781%
Long-term debt	47.81%	4.54%	2.1706%
Total	100.00%		7.2487%

The weighted average rounds to 7.25%. Applying the same capital weights and debt cost to the 9.48% and 9.98% equity endpoints yields approximately 7.1182% and 7.3791%, respectively, which round to 7.12% and 7.38%. The calculation implements Staff's recommended components; it does not add a separate premium to them.

At the agreed true-up capital weights and debt cost, substituting EMM's 10.50% ROE for Staff's 9.73% increases the overall return by approximately 0.4019 percentage points, or 40.19 basis points. That is approximately $4.019 million in additional annual return per $1 billion of applicable rate base, before associated income-tax effects. This is an arithmetic comparison of the stated components, not a quantified case revenue requirement. The size of the difference underscores why the unsupported equity premium should not be passed through to customers.

[150] *Id*, p. 66, ll. 1-4; *see also* Schedule SJW-TD-2.

Conclusion

Staff requests that the Commission adopt (A) EMM's actual June 30, 2026, standalone capital structure of 52.19% common equity and 47.81% long-term debt, (B) an embedded long-term debt cost of 4.54%, (C) an authorized common equity return of 9.73% within a range of 9.48% to 9.98%, and (D) an overall rate of return of 7.25% within a range of 7.12% to 7.38%. Those determinations reasonably compensate EMM's capital while protecting customers.

Travie J. Pringle

Issue 3: Other Revenues

A. What is the appropriate level of net revenue to reflect in the cost of service and other models for Large Load Power Service ("LLPS") and other large customers?

i. What is the appropriate revenue adjustment for expected future revenues from Schedule LLPS customers in the cost of service model?

The issues before the Commission regarding "Other Revenues" involves the following issues: (A) What is the appropriate level of net revenue to reflect in the cost of service and other models for Large Load Power Service ("LLPS") customers, and (i) What is the appropriate revenue adjustment for expected future revenues from Schedule LLPS customers in the cost of service model?

As explained more fully in this initial brief, the Commission should reject the *LLPS Partial Stipulation and Agreement* ("LLPS Agreement" or "Stipulation V") entered into between EMM and Google, and order the following Staff recommendations as the proper resolution of the issues listed above:

A. The appropriate level of net revenue to reflect in the cost of service and other models for LLPS customers is *** [redacted] ***.[151] However, this is ultimately a policy matter for the Commission. The number used by Staff in its case, which included a 12-month annualization of Year 1 contract demand for Customer A of *** [redacted] ***. The record, though, supports higher values if the Commission decides an appropriate level of net revenue should be higher. The record supports approximately *** [redacted] *** if the Commission considered an annualization of *** [redacted] *** of revenue calculated using a Year 1 contract demand of *** [redacted] *** and *** [redacted] *** of revenue calculated using Year 2 contract demand of *** [redacted] ***.[152] Using the LLPS Agreement's own calculations, the correct value is approximately *** [redacted] ***, or the value could be as high as *** [redacted] ***.[153]

A.i. Staff recommends the LLPS class be ordered an equal percentage increase to each rate component based on the system average increase. Staff's recommended iterative approach, with an example, is provided in Exhibit 167, the Surrebuttal/True-up Direct Testimony Sarah L.K. Lange, at page 41 line 8, through page 42 line 16, and footnote 28.

Introduction

This proceeding presents the Commission with an important opportunity to address the treatment of revenues generated by some of the largest electric customers in EMM's service territory. Specifically, the Commission must determine how revenues associated

[151] Exhibit 167, Surrebuttal/True-Up Direct Testimony of Sarah L.K. Lange, p. 41, ll. 8-10 and p. 42, ll. 1-2.
[152] *Id*, pp. 39-40.
[153] Exhibit 3, Highly Confidential Attachment B to Staff Objection to LLPS Partial Stipulation and Agreement, On-the-Record Presentation, October 13, 2026.

with LLPS customers should be reflected in EMM's revenue requirement when those customers' electric usage is increasing significantly and their historical billing information does not necessarily reflect their anticipated operations during the period rates established in this case will be in effect.

Staff's position is straightforward. The Commission should establish rates using a reasonable and supportable calculation of the net revenues attributable to these customers, taking into account the revenues reasonably expected from their electric usage, the incremental costs associated with serving that usage, and the amounts already reflected in EMM's cost-of-service models.

The Commission should not adopt an adjustment merely because it represents the negotiated compromise of EMM and an individual large-load customer. Nor should it assume that annualizing one month of billing information necessarily produces a representative estimate of revenues attributable to customers whose demand and energy usage are changing materially.

The evidence establishes that Staff conducted an independent analysis of large-customer (LPS and LLPS) revenues, supported by the testimony of Staff witnesses Sarah L.K. Lange, Amanda Rucker, and J Luebbert. Staff's analysis recognizes both the financial benefits associated with additional customer revenues and the corresponding costs of serving additional load. Staff's methodology also accounts for the distinction between revenues already reflected in the cost of service and additional revenues that must be recognized through a separate adjustment.

By contrast, the LLPS Agreement entered into by EMM and Google proposes a $60 million revenue adjustment based on an annualization of June 2026 billing information. As EMM witness Darrin Ives acknowledged during the October 13, 2026, on-the-record presentation, the $60 million figure is a negotiated, rounded amount rather than the product of Staff's independent cost-of-service analysis.[154]

The Commission should adopt Staff's supported revenue adjustment rather than the amount agreed to between EMM and Google in the LLPS Agreement.

Argument

I. The Commission should recognize the net revenues associated with large load customers when determining EMM's revenue requirement.

The Commission is vested with the power of the state "to set 'just and reasonable' rates for public utility services..."[155] that provide the utility an opportunity to recover its reasonable cost of providing electric service, including an appropriate return on investment, without requiring customers to pay more than is reasonably necessary. The Commission is also entrusted to protect consumers. "[T]he dominant thought and purpose of the policy is to protect the public while the protection given the utility is merely incidental."[156]

This balancing act requires consideration of the utility's expected revenues as well as its expenses. When a utility begins serving substantial additional electric load,

[154] Unofficial Tr. Vol. 12 (Public), pp. 93-96. (The unofficial transcript does not contain page or line numbers. For citations purposes, the page numbers referenced are when reviewing the transcript in Adobe; the page number box would read "93 of 280" as the starting point).
[155] *St. ex rel. City of Harrisonville v. Pub. Serv. Comm'n of Missouri,* 291 Mo. 432, 236 S.W. 852 (1922).
[156] *State ex rel. Crown Coach Co. v. Public Service Com'n,* 238 Mo.App. 287, 179 S.W.2d 123, 126 (1944).

the revenues attributable to that load can materially affect the amount that must be recovered from its other customers.

Staff witness Sarah L.K. Lange explains that the annualization of large-load customers affects both EMM's revenues and the expenses associated with serving those customers. Accordingly, Staff's analysis does not treat all additional billing revenues as incremental net income. Instead, it considers the corresponding changes in the cost of service to determine the net effect on EMM's revenue requirement.[157] This distinction is particularly important in this rate case because of the substantial magnitude of the load associated with customers taking or expected to take service under Schedule LLPS.

Large-load revenues are material to the determination of rates for other customers. Indeed, the LLPS Agreement itself recognizes that additional revenues from large-load customers should reduce the Company's revenue requirement. Its signatories propose a $60 million adjustment for that purpose.

Thus, the principal disagreement is not whether large-load revenues should be recognized. Rather, it concerns the appropriate methodology and amount. The Commission should resolve that disagreement by adopting the adjustment supported by Staff's independent analysis of customer usage, billing determinants, and incremental costs.

II. Staff's individualized annualization methodology provides a reasonable basis for calculating large load customer revenues.

As explained by Ms. Lange, Staff ordinarily evaluates customer growth and usage changes by rate code and customer class. However, for particularly large customers,

[157] Exhibit 177, Conforming Testimony of Sarah L.K. Lange, p. 2, ll. 18-27 and p. 3, ll. 1-9.

including those served under large-power and special tariff arrangements, Staff may perform an individualized annualization based on the customer's specific circumstances.[158] Such individualized treatment is appropriate because the addition or expansion of a single large customer can produce changes in electric demand and energy usage that are disproportionate to ordinary fluctuations within a customer class.

Importantly, Staff's methodology does not depend upon assuming that every large customer will immediately consume electricity at its maximum contracted capacity. Rather, it uses available information concerning expected usage and the applicable rates to develop a reasonable annualized revenue estimate. The Commission should find that this individualized methodology is appropriate for determining the revenues attributable to large customers whose usage patterns are changing materially.

III. The appropriate revenue adjustment must account for incremental costs and avoid double counting.

An accurate calculation of large-load net revenues must consider the expenses associated with serving additional load. Incremental electric usage can produce additional energy costs and transmission-related expenses. Failure to recognize those expenses would overstate the net revenue attributable to large-load customers.

Ms. Lange's testimony addresses the treatment of incremental energy costs and the relationship between additional load, production-cost modeling, and EMM's revenue requirement.[159]

[158] Ex. 177, pp. 18, ln. 1 through p. 21, ln. 15.
[159] *Id*, p. 24, ll. 7 through p. 27, ll. 6.

Staff witness J Luebbert separately addresses incremental transmission-related expenses associated with additional electric load. His analysis uses applicable Southwest Power Pool ("SPP") transmission charges and demand- and energy-related billing determinants to estimate expenses attributable to additional load.[160] Mr. Luebbert's testimony supports the conclusion that the Commission should evaluate additional large-load revenues together with the identifiable transmission expenses associated with serving those customers.

Staff's methodology also addresses another essential consideration: avoiding the double counting of revenues already reflected in the cost of service. As Ms. Lange explains, certain annualized large-customer revenues and energy usage are already incorporated into Staff's underlying cost-of-service calculations. Consequently, a separate revenue adjustment must exclude amounts already accounted for in those models.[161] Without this adjustment, the same revenues could be credited more than once, distorting the resulting revenue requirement.

Conversely, excluding incremental revenues simply because the corresponding load cannot be represented with precision in every other cost-of-service model would fail to recognize a material financial benefit to the utility. The Commission should therefore adopt a methodology that recognizes additional revenues, deducts the associated incremental costs, and accounts for amounts already incorporated into the cost of service.

[160] Exhibit 109, Direct Testimony of J Luebbert, pp. 2-4.
[161] Ex. 177, p. 17, ll. 1-4.

IV. The absence of complete hourly load information does not justify disregarding reasonably supportable large load revenues.

The evidence demonstrates that large-load annualization presents challenges beyond the calculation of annual kilowatt-hour usage. Ms. Lange explains that production-cost modeling and jurisdictional allocation calculations require detailed information concerning customer load characteristics, including hourly consumption patterns, monthly demands, and the timing of peak usage.[162] A single annual load-factor assumption does not necessarily capture all of these characteristics. Indeed, two customers with similar annual energy usage may impose substantially different costs depending on when their electric demand occurs.[163]

Ms. Lange's testimony further explains that Staff's ability to incorporate certain additional large-load adjustments into production-cost modeling was limited by the availability of sufficiently detailed customer information.[164] The Commission should recognize the distinction between estimating annualized customer revenues and precisely modeling the hourly effect of additional load on every component of the utility's system.

Staff's inability to incorporate an adjustment into every model with equal precision does not mean that the additional revenue should be disregarded. Instead, the Commission should recognize the supported financial effects while avoiding unsupported assumptions concerning the timing and characteristics of future load. Only Staff's adjustment avoids unsupported assumptions and is the best reliable estimate in light of EMM's inability to

[162] *Id*, pp. 24, ll. 7 through p. 27, ll. 6.
[163] *Id*, pp. 25, ll. 3-17.
[164] *Id*, p. 23, ll. 5-15.

provide the relevant and sufficiently detailed customer information. This approach is consistent with Staff's broader objective of producing a reasonable and internally consistent cost of service calculation.

V. Staff's October 6 objection and supporting exhibits provide an evidentiary basis for rejecting the $60 million adjustment proposed by Evergy and Google.

On October 6, 2026, Staff filed its *Objection to the Non-Unanimous Partial Stipulation and Agreement Regarding Large Load Power Service Issues*. The objection challenged, among other matters, the revenue and energy quantities proposed in the agreement between EMM and Google. The disagreement over those quantities is material to the Commission's determination of the appropriate revenue requirement. The LLPS Agreement does not merely affect the allocation of costs among customer classes; it determines how much additional revenue from LLPS customers will be recognized in calculating the amount EMM must recover through rates. The Commission should therefore evaluate the underlying assumptions and calculations, rather than adopt the stipulated amount without independent examination.

Staff's objection was accompanied by Attachments A and B. During the October 13, 2026, on-the-record presentation, Staff offered those attachments as Staff Exhibits 2 and 3, respectively. The regulatory law judge confirmed their identification, considered objections, and admitted both exhibits into the evidentiary record.[165]

The admission of this evidence is significant. The Commission is not confined to considering only the information used by EMM and Google in negotiating their stipulated

[165] Unofficial Tr. Vol. 12 (Public), pp. 196–198

revenue adjustment. It may consider the additional evidence presented by Staff, including the information reflected in the admitted attachments, in determining the appropriate treatment of expected large-load revenues.

The fact that information was received after the true-up cutoff does not, by itself, establish that the information is irrelevant to evaluating the reasonableness of a forecast or annualization. Many aspects of the LLPS Agreement were provided well after the true-up cut off without factual support. The Commission may distinguish between using later information to test the reliability of an estimate and improperly expanding the true-up period.

The Commission's true-up cutoff does not, by itself, deprive it of authority to consider otherwise relevant evidence concerning subsequent events. Section 393.150 authorizes the Commission to determine the propriety of proposed rates after a full hearing, but "neither prescribes nor limits the methodology that the Commission may use in determining rates."[166] Section 393.270.4 further authorizes consideration of all facts bearing upon a proper determination of rates. Historical periods therefore serve the prospective ratemaking inquiry; they do not displace it. As *State ex rel. Missouri Power & Light Co. v. Public Service Commission* explains, the test year supplies a basis for projecting conditions during the period when rates will be effective.[167] Consistent with that purpose, post-test-year adjustments are evaluated according to whether they are known and

[166] *State ex rel. Associated Natural Gas Co. v. Public Service Commission*, 706 S.W.2d 870, 880 (Mo. App. W.D. 1985).
[167] *State ex rel. Missouri Power & Light Co. v. Public Service Commission*, 669 S.W.2d 941, 945 (Mo. App. W.D. 1984).

measurable, preserve the proper relationship among investment, revenues, and expenses, and represent anticipated conditions while rates are effective.[168]

The relevant distinction is between considering evidence and adopting a resulting adjustment. The Commission retains discretion to reject an adjustment whose financial effects are insufficiently known and measurable.[169] That discretion does not establish a categorical evidentiary prohibition based solely on the true-up date. Indeed, in *Office of Public Counsel v. Evergy Missouri West, Inc.*, the court recounted the Commission's finding that parties could have proposed an isolated adjustment outside both the test year and true-up date had they known of the generating plant's cessation of operations and impending retirement.[170] Accordingly, an objection resting solely on the timing of the underlying events should be rejected. The Commission may consider the evidence and determine its appropriate weight and ratemaking consequences in light of reliability, matching, and representative future conditions.

Staff submits that the Commission should evaluate the assumptions and calculations reflected in Staff Exhibits 2 and 3 from the on-the-record presentation alongside the testimony of Staff witnesses Lange and Luebbert in determining the appropriate net-revenue adjustment.

[168] *State ex rel. GTE North, Inc. v. Missouri Public Service Commission*, 835 S.W.2d 356, 368 (Mo. App. W.D. 1992).
[169] *In re Empire District Electric Co.*, 630 S.W.3d 887 (Mo. App. W.D. 2021).
[170] *Office of Public Counsel v. Evergy Missouri West, Inc.*, 609 S.W.3d 857 (Mo. App. W.D. 2020).

VI. The $60 million stipulated adjustment is a negotiated compromise, not an independently established measure of expected net revenues.

The testimony of EMM witness Darrin Ives confirms that the revenue adjustment proposed by EMM and Google resulted from a different methodology than the one employed by Staff. Mr. Ives explained that the stipulation's signatories relied upon June 2026 billing information and annualized that information to develop their proposed adjustment.[171]

However, the annualization of a single month of billing information does not necessarily provide a representative estimate of future revenues for customers whose demand and energy usage are increasing materially. Staff's methodology, by contrast, considers the customer-specific information necessary to estimate annualized revenues and the incremental costs associated with serving additional load.[172]

Mr. Ives also acknowledged that EMM's earlier calculation was approximately $43 million and that the $60 million figure was a rounded amount resulting from negotiations with Google.[173] He further confirmed that Staff's adjustment of *** [redacted] *** was closer to EMM's adjustment in testimony of approximately $43 million than the $60 million agreed to with Google in the LLPS Agreement.[174] In fact, Staff's adjustment is almost half-way between EMM's initial adjustment and the adjustment agreed to with Google.

The relevant question is not whether EMM and Google reached a compromise. The relevant question is whether the resulting adjustment reasonably reflects the net revenues expected from the additional load, consistent with the other components of the

[171] Unofficial Tr. Vol. 12 (Public), pp. 59–61.
[172] Ex. 161, pp. 1-3.
[173] Unofficial Tr. Vol. 12 (Public), pp. 93–96.
[174] *Id*, p. 95.

cost-of-service calculation. Staff's independent analysis, supported by the testimony of Ms. Lange and Mr. Luebbert and the evidence admitted as Staff Exhibits 2 and 3 during the on-the record presentation, provides the appropriate basis for that determination. The Commission should reject the stipulated $60 million adjustment on the basis that it is incorrect per the LLPS Agreements own terms.

As Ms. Lange stated during the evidentiary hearing, *** [redacted] ***[175]

As she further explained, *** [redacted] ***[176]

VII. Staff witness Sarah L.K. Lange's live testimony confirms that additional LLPS revenues must be evaluated in light of the risk of over-recovery and positive regulatory lag.

The Commission should also consider the testimony provided by Staff witness Sarah Lange during the October 13 on-the-record presentation concerning the financial

[175] Tr. Vol. 7 (Highly Confidential), p. 64, ll. 5-10.
[176] *Id*, p. 64, ll. 20 through p. 65, ll. 5.

consequences of large-load growth. In response to questions from the regulatory law judge, Lange addressed the consequences of establishing rates using an inaccurate estimate of future large-load revenues, explaining that the Commission should focus on mechanisms that mitigate the risk of over-recovery associated with additional LLPS revenues.[177]

Ms. Lange distinguished the risk of under-recovery from the risk of over-recovery. If EMM's actual revenues prove insufficient, the Company retains the ability to initiate another rate proceeding. However, when actual revenues exceed the amount recognized in rates, existing customers may continue paying rates that do not fully reflect the additional revenues generated by large-load customers.[178] Ms. Lange explained that this creates a concern involving positive regulatory lag. While regulatory mechanisms may protect a utility against increases in costs between rate cases, those mechanisms do not necessarily provide corresponding protection to customers when the utility experiences substantial additional revenues.[179] The interaction of mechanisms mitigating negative regulatory lag while preserving the utility's benefit from positive regulatory lag can cause non-LLPS customers to bear costs that should otherwise be reduced by the growth of LLPS customers.[180] Ms. Lange's testimony reinforces the importance of establishing a reasonable large-load revenue adjustment in this rate case.

The Commission should not ignore reasonably supportable additional revenues merely because their precise amount cannot be predicted with certainty. Doing so risks

[177] Unofficial Tr. Vol. 12 (Public), pp. 184–186.
[178] *Id*, pp. 185-186.
[179] *Id*.
[180] *Id*.

establishing rates that overstate the amount EMM must recover from existing customers. At the same time, Staff does not advocate for an unsupported or speculative adjustment. The appropriate response to forecast uncertainty is to adopt the most reasonable calculation supported by the record and to consider appropriate mechanisms for addressing subsequent changes.

The Commission should adopt Staff's net-revenue adjustment and reject an alternative methodology that does not adequately account for the expected financial benefits of large-load growth.

VIII. The Commission can establish rates using Staff's supported revenue adjustment notwithstanding limitations in class cost-of-service modeling.

Ms. Lange's October 13 testimony also clarifies the distinction between the information needed to establish EMM's overall revenue requirement and the information needed to perform a complete class cost-of-service study. During questioning by the regulatory law judge, Ms. Lange explained that limitations in available data may impede the completion of a class cost-of-service study without preventing the Commission from establishing rates.[181]

The addition of large-load customers can materially affect production, transmission, and administrative and general cost allocations. Lange expressly acknowledged the substantial effect of LLPS load on those components of a class cost-of-service analysis.[182] Ms. Lange also explained that Staff uses hourly customer load and applicable locational marginal prices when performing class cost-of-service analyses where sufficient data is

[181] *Id*, pp. 184–185.
[182] *Id*, pp. 194–195.

available.[183] These observations demonstrate that the cost of serving additional load depends upon more than the total annual amount of electricity consumed. The timing and characteristics of consumption are relevant to the associated costs.

Nevertheless, the absence of sufficient information to perform every allocation with precision does not establish that the Commission should disregard the revenues associated with additional load. Instead, the Commission should recognize the supported net revenues in determining the revenue requirement while avoiding unsupported adjustments to other models. Staff's recommended treatment reflects this distinction. It recognizes additional revenues and identifiable incremental costs without presuming that incomplete customer load information can support every possible adjustment to production-cost or class cost-of-service modeling.

IX. The Commission should distinguish the present revenue adjustment from mechanisms designed to address future LLPS revenue growth.

Finally, the Commission should distinguish the determination of the appropriate revenue adjustment in this proceeding from the separate question of how subsequent changes in large-load revenues and expenses should be addressed.

During the October 13 proceeding, Ms. Lange discussed the potential use of trackers and earnings-sharing mechanisms to address changes in financial results attributable to large-load customers.[184] She explained that Staff's position favored an earnings-sharing mechanism, similar to the mechanism employed for Ameren Missouri, rather than a literal tracker. Lange also identified other Staff witnesses as better positioned to address the

[183] *Id*, pp. 164–167.
[184] *Id*, pp. 186-189.

specific design of that mechanism.[185] The earning-sharing mechanism is more thoroughly argued later on in this brief.

This testimony illustrates the broader concern underlying Staff's position: large-load growth may materially change EMM's financial circumstances between general rate proceedings. That being said, the possibility of employing a future earnings-sharing mechanism does not eliminate the Commission's obligation to establish an appropriate revenue requirement in this case.

Conclusion

For the foregoing reasons, Staff requests the Commission issue an order identifying the appropriate level of net revenue to reflect in the cost of service and other models for LLPS customers is *** [redacted] ***. The Commission should also order that the LLPS class be ordered an equal percentage increase by class and rate component. Staff's recommended iterative approach, with an example, is provided in Exhibit 167, the Surrebuttal/True-up Direct Testimony Sarah L.K. Lange, at page 41 line 8, through page 42 line 16, and footnote 28. The record, though, supports higher values if the Commission decides an appropriate level of net revenue should be higher.

The record supports approximately *** [redacted] *** if the Commission considered an annualization of *** [redacted] *** of revenue calculated using a Year 1 contract demand of *** [redacted] *** and *** [redacted] *** of revenue calculated using Year 2 contract demand of *** [redacted] ***.[186] Using the LLPS Agreement's own calculations, the correct value is approximately *** [redacted] ***, or the value could be as high as *** [redacted] ***.[187]

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[185] *Id*.
[186] Ex. 167, pp. 39-40.
[187] Exhibit 3, Highly Confidential Attachment B to Staff Objection to LLPS Partial Stipulation and Agreement, On-the-Record Presentation, October 13, 2026.

Issue 5. Fuel and Purchased Power

A. What should be adopted as the variable fuel and purchased power cost for this case?

B. What fuel prices should be included in the cost of service?

C. What normalized market prices should be used to determine the revenue requirement in this case?

D. What level of Transmission Congestion Rights ("TCR") revenue, not TCR margin, should be included in the cost of service?

As a preliminary matter, EMM and Google submitted Stipulation V (LLPS) settling all of Issue 5 between the two parties.[188] Notably, EMM witness JP Meitner stated in hearing that as part of this stipulation, EMM and Google adopted Staff's modeling of the fuel prices.[189]

Issue 5(A) Staff Recommends the Commission Adopt Staff's Proposed Variable Fuel and Purchased Power Costs.

Staff witness Brodrick Niemeier's evaluation on this issue is based upon input from other Staff witnesses which Mr. Niemeier then applied to Staff's production cost model.[190] Based on this model, Mr. Niemeier recommended to the Commission that the variable fuel and purchased power expense be $268,858,956 and that this figure be reflected in the revenue requirement.[191]

EMM witness Hsin Foo asserted a number of concerns regarding Staff's production cost model – three of which are pertinent to the instant issue and will be addressed in this section.

Ms. Foo asserts that Staff's production cost model dispatches the Wolf Creek Nuclear Generating Station ("Wolf Creek") "as though it regularly increases and decreases

[188] LLPS Stipulation Docket Item No. 317, page 4.
[189] Unofficial Tr. Vol. 8, p. 67, l. 23 – p. 68, l. 2.
[190] Direct Testimony of Brodrick Niemeier, page 2, line 18 – page 3, line 3; page 4, lines 18 – 22.
[191] Surrebuttal True-Up Direct Testimony of Brodrick Niemeier, page 1, lines 20-22.

output in response to changing market conditions."[192] Ms. Foo posits that this is contrary to how Wolf Creek typically operates. According to Ms. Foo, Wolf Creek will generally operate at or near full capacity (notwithstanding scheduled outages or other operational limitations).[193]

Staff does not dispute that Wolf Creek typically operates at or near full capacity. However, as discussed at length by Mr. Niemeier, Wolf Creek does experience derates and "…does occasionally operate at a significantly reduced capacity."[194] Staff's production cost model reflected these considerations and was based upon the information Staff had at the time.[195] During the true-up period in this case, Staff updated its production cost model – including an increase to Wolf Creek's minimum capacity. This update better reflects EMM's operation of Wolf Creek.[196]

Ms. Foo next asserts "every coal-fired generating unit in Staff's model is dispatched below its five-year average."[197] Staff does not dispute that, compared to a five-year average, "Staff's coal generation was significantly lower."[198] But, the coal generation in Staff's direct production cost model – when compared with a four-year average – is "**much closer** to the **historical** average."[199] Thus, Staff's production cost model is reasonable.

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[192] Rebuttal Testimony of Hsin Foo, page 12, line 23 – page 13, line 1; Surrebuttal-True-Up Direct of Brodrick Niemeier, page 2, lines 15-16.
[193] Rebuttal Testimony of Hsin Foo, page 12, lines 11 – 17; Surrebuttal-True-Up Direct of Brodrick Niemeier, page 2, lines 13-14.
[194] Surrebuttal-True-Up Direct of Brodrick Niemeier, page 3, lines 1-7.
[195] Surrebuttal-True-Up Direct of Brodrick Niemeier, page 3, lines 7-10.
[196] Surrebuttal-True-Up Direct of Brodrick Niemeier, page 3, lines 10-12.
[197] Rebuttal Testimony of Hsin Foo, page 14, lines 3-4; Surrebuttal-True-Up Direct of Brodrick Niemeier, page 3, lines 15-16.
[198] Surrebuttal-True-Up Direct of Brodrick Niemeier, page 3, lines 19-20.
[199] Surrebuttal-True-Up Direct of Brodrick Niemeier, page 3, line 20 – page 4, line 6. [Emphasis added.]

Lastly, Ms. Foo argues that Greenwood Solar should not be included in Staff's fuel and purchase power expense calculation – stating that the unit belongs to Evergy Missouri West ("EMW").[200] Staff's approach regarding this issue accounts for the report and order issued by the Commission in Commission File No. EA-2015-0256. In this report and order, the Commission stated:

> The Commission is concerned that only GMO ratepayers will bear the cost of the [Greenwood Solar] project. The Commission will not make any specific ratemaking decisions in this case. Those will be reserved for GMO's pending rate case. However, the matter will once again come before the Commission when GMO seeks to add the plant to its rate base. At that time, the Commission will expect GMO to propose a means by which those costs will be shared with KCP&L's customers who will also benefit from the lessons learned from this pilot project.[201]

In light of the Commission's concerns above, in every rate case subsequent to this order, Staff has allocated Greenwood Solar to both EMM and EMW.[202]

In addition to the Wolf Creek true-up period update discussed above, Staff also "updated outages, renewable generation, load, market prices and fuel prices" in its production cost model during the true-up period.[203]

Issue 5(B) Staff Recommends the Commission Include Staff's Fuel Prices in the Cost of Service.

The fuel prices in dispute between Staff and EMM are natural gas and coal prices. Staff witness Antonija Nieto developed the prices for both abovementioned fuel types.

[200] Rebuttal Testimony of Hsin Foo, page 15, lines 10-12; Surrebuttal-True-Up Direct of Brodrick Niemeier, page 5, lines 10-11.
[201] Surrebuttal-True-Up Direct of Brodrick Niemeier, page 5, lines 12-16; Commission File No. EA-2015-0256, Docket Item No. 84, Report and Order, pages 16-17.
[202] Surrebuttal/True-Up Direct of Brodrick Niemeier, page 5, lines 16-17.
[203] Surrebuttal/True-Up Direct Testimony of Brodrick Niemeier, page 6, lines 2-4.

Staff recommends a 12-month weighted average ending June 30, 2026, for the natural gas price calculation.[204]

Natural Gas Price Calculation:

Staff's natural gas price calculation relies on known, historical data.[205] On the other hand, EMM's calculation relies on a combination of historical and forecasted, speculative data. Specifically, EMM witness JP Meitner proposes that the Commission adopt a natural gas price calculation which uses "actual prompt-month pricing from January 2025 through June 2026, and forward market prices as of July 1, 2026, for the remaining eighteen months of the three-year normalization period."[206]

By using a combination of past and forward-looking data, EMM's approach runs afoul of the Known and Measurable Principle and the Matching Principle. Ms. Nieto describes the Known and Measurable Principle below:

> The Known and Measurable Principle requires that any adjustment made to historical test year data must be certain in amount, verifiable, and the event causing the change must have occurred or be contractually/legally certain to happen within the true-up period.[207]

Simply put, EMM's use of forward market prices from June of 2026 to eighteen months past June 2026 uses data that is not "certain in amount;" it is not verifiable, and it is not "contractually/legally certain to happen within the true-up period."[208]

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[204] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 5, lines 20-22.
[205] In describing Staff's methodology, Ms. Nieto states, "[a] 12-month weighted average of natural gas prices through June 30, 2026, is based on actual commodity settlement prices and utility purchase costs realized during the true-up period. It is verified and mathematically measurable." Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 5, lines 5-8.
[206] True-Up Rebuttal Testimony of JP Meitner, page 2, lines 14-17.
[207] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 4, lines 6-9.
[208] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 4, lines 6-9.

Ms. Nieto also states, "[t]he Matching Principle requires that all components of ratemaking formula – rate base, revenues, operating expenses, and billing determinants – be synchronized over the same time-period and operating conditions."[209] She further specifies that this principle requires "revenues, operating expenses, and capital investments" to be "evaluated over the same operational period."[210]

Staff's approach adheres to this principle because, "[b]y using the 12-month period ending June 30, 2026, Staff aligns its natural gas commodity costs directly with the true-up period used across all cost components of this rate case."[211]

Coal Price Calculation:

For Staff's coal price calculation, Staff used the actual prices as of the 12-months ending June 30, 2026, for the coal price calculation.[212] Staff's coal price calculation also adheres to the Known and Measurable Principle and the Matching Principle.

Issue 5(C) Staff Recommends the Commission Adopt Staff's Normalized Market Prices to Determine the Revenue Requirement in This Case.

Staff witness Justin Tevie, whose testimony was adopted by Staff witness J Luebbert, used historical, raw data from the Southwestern Power Pool ("SPP") in order to construct the market prices inputted into Staff's production cost model.[213] Moreover, Mr. Tevie

[209] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 4, lines 4-6.
[210] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 5, lines 15-16.
[211] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 5, lines 16-18.
[212] Direct Testimony of Antonija Nieto, page 23, lines 1-6; Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 11, lines 9-20.
[213] Direct Testimony of Justin Tevie, page 2, lines 18-19 and page 3, line 10 – page 4, line 11.

updated these market prices during the true-up period in this case – using "two years of data ending June 30, 2026 for all nodes included" in Staff's production cost model.[214]

Thus, Staff used the most up-to-date data possible while still adhering to the Known and Measurable Principle and the Matching Principle discussed above in section 5(B).

Issue 5(D) Staff Recommends the Commission Include Staff's Recommended Level of Transmission Congestion Rights ("TCR") Revenue in the Cost of Service.

Historically, there are multiple methods by which TCR's have been included in the revenue requirement. This includes the approach Staff used in the current case. In the current case, Staff used a "historic TCR margin revenue for a given period." Specifically, Staff used the 12 months ending as of the true-up cutoff as the TCR margin to be used in developing the revenue requirement.[215]

This approach adheres to the Known and Measurable Principle as well as the Matching Principle (discussed at length in Section 5(B)). It is also worth noting that both Staff and EMM both used this methodology in EMM's most recent prior rate case, Commission File No. ER-2022-0129.[216]

Andrea B. Hansen

[214] Surrebuttal/True-Up Direct Testimony of Justin Tevie, page 3, lines 4-5.
[215] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 7, lines 7-8 and page 8, line 27.
[216] Surrebuttal/True-Up Direct Testimony of Antonija Nieto, page 7, lines 11-22.

Issue 15. Income Taxes

A. How much income tax expense should be included in rates?

i. Should income tax expense be reduced by a normalized disposition loss deduction?

Staff Position: Income tax expense should not be reduced by a normalized disposition loss deduction, which is a tax accounting mechanism used when a utility retires or sells an asset at a financial loss. Disposition losses are typically only reflected on a tax return and are not included in a utility's regulatory accounting records and as such, the retirement of an asset does not change EMM's net rate base even though the retirement is used as a deduction for tax purposes. The difference between EMM's book basis and tax basis regarding a retired asset is accounted for in the Accumulated Deferred Income Taxes (ADIT) deduction to rate base that effectively reduces the dollar amount included in rates for EMM's rate of return until the temporary difference unwinds.[217]

A disposition loss deduction should not be included because the deduction that resulted from the loss is included in the book to tax difference, commonly known as the ADIT, which is increased by the deduction. When ADIT is increased by that deduction, the rate base is reduced and reduces the net investment on which customers pay a rate of return. This difference will be reflected in the balance included in the cost of service, and over time will benefit customers through reductions in rate base.

C. What amount of net operating loss deferred tax assets should be included in rate base?

Staff Position: EMM's ADIT book balance on June 30, 2026, should be reflected in rate base. This includes the unamortized balance of EMM's deferred tax liabilities and net

[217] Young Rebuttal, Pg. 8, Lines 7-12.

operating loss carryforward (NOLC) tax assets that were remeasured with the implementation of the 2017 Federal Tax Cut and Jobs Act. The tax assets and liabilities were created by the same event and the accounting for the rate base values are inextricably linked. Also, this approach reflects the unopposed Stipulation and Agreement reached in EMMs prior rate case, No. ER-2018-0145.[218]

Carolyn H. Kerr

Issue 16. Income-Eligible Programs

E. Should the Commission approve the creation of a low-income rate or assistance program that waives EMM's customer charge for qualifying customers in this case, or should such a program continue to be developed in the Affordability Workshop?

Background: On October 7, 2026, EMM, Staff, and Renew Missouri filed Stipulation IV (Programs).[219] Stipulation IV resolves Issue 16 concerning Income-Eligible Programs, specifically sub-issues A-D and F-H.[220] Google and MECG did not oppose this agreement.[221] However, OPC objected solely to the non-enactment of a customer charge waiver program identified in Issue 16.E.[222] Pursuant to state regulation, the timely objection instructs the Commission to treat Stipulation IV and the issues it settles as the signatory parties' stipulated position, without binding those parties, and allows the Commission to decide remaining issues after the hearing.[223]

The Commission held an evidentiary hearing regarding this issue and others from October 5, 2026, through October 13, 2026. The Commission further held an on-the-record

[218] Young Rebuttal, page 5, line 7 through page 6, line 2.
[219] EFIS Item No. 320 *Non-Unanimous Programs Stipulation and Agreement* (Stipulation IV).
[220] *Id*.
[221] *Id* at 7.
[222] *Id*.
[223] 20 CSR 4240-2.115(2)(D).

presentation on October 13, 2026, so that the Commission could question the parties about the stipulations and agreements in this case.[224]

OPC witness Geoff Marke proffers "a placeholder recommendation for an income-eligible rate design that waives the customer charge for residential customers whose incomes are at or below 150% of the federal poverty line. . . ."[225] This placeholder recommendation is the foundation for OPC's objection to resolving Issue 16.E. as part of Stipulation IV in this case.

Staff Position: Staff supports Stipulation IV and the exclusion of the creation of a customer charge waiver program because Staff, EMM, and the Commission lacks the data required to establish eligibility criteria, determine the impacts of such a program design, and analyze the potential impacts to other EMM customers.[226] At this time, EMM does not have the necessary data or measurable parameters to justify the creation of a customer charge waiver program. The expansive program outline offered by Dr. Marke offers little more than a place holder for substantial work to be done in the affordability docket and provides no insight into the practical and financial impacts of the program. Dr. Marke identifies the program as "one option to move forward."[227] Absent customer eligibility parameters, financial limitations on the program, and the varying unknown costs such as administrative expenses, creating such a program is impracticable and places a heavy burden upon EMM. OPC's own witness agrees that utility companies cannot be social services, and that this

[224] Case No. ER-2026-0143, *Order Setting on-the-record Presentation*.
[225] Ex. 202, Direct Testimony of Geoff Marke, p. 52, lines 7-9, Confidential.
[226] Ex. 135, Direct Testimony of Tammy Huber, p. 3, lines 8-10.
[227] TR., Vol.8, p. 125, lines 3-4.

program would burden the company with sensitive information.[228] Further supported by the fact that the financial impact is uncertain.[229] Staff expert Tammy Huber identifies various factors that should be considered in creating a customer charge waiver program for EMM.[230]

Determining program parameters, consolidating the data, and recommending programs are exactly why the Commission ordered an affordability docket.[231] "As part of this working case, representatives from the Commission, the Office of the Public Counsel, and any other interested stakeholders will have the opportunity to review the currently existing utility affordability programs designed for low-income and senior residential customers and may work to make recommendations or engage in further dialogue[.]"[232]

Here, OPC would circumvent Commission orders by establishing a program based entirely on its own parameters. The parameters set out by Dr. Marke require coordination with outside government agencies and overlook the inherent privacy concerns of EMM customers.[233] Staff agrees, as Dr. Marke testifies, that the Commission cannot order this.[234] Staff recommends that EMM, Staff, and other stakeholders continue to work together through the Affordability Docket (OW-2026-0085) to develop cost effective and targeted approaches to the possible creation of low-income rates and/or assistance programs that benefit customers in need. Further, Staff recommends the Commission reject OPC's proposal for a customer charge waiver program.

[228] TR., Vol.8, p. 133.
[229] TR., Vol.8, p. 126-127.
[230] Ex. 135, Direct Testimony of Tammy Huber, p. 7, lines 10-16.
[231] Commission Order, Case No. OW-2026-0085.
[232] *Id*.
[233] Ex. 202, Direct Testimony of Geoff Marke, p. 52 -54, Confidential.
[234] Ex. 202, Direct Testimony of Geoff Marke, p. 54, lines 18-19, Confidential.

If the Commission approves an income-eligible rate design customer charge waiver, Staff recommends tariff language detailing the program. The tariff should include the purpose of the program including necessary definitions, defined eligibility requirements, a limit on the number of participants and budget parameters that detail how long the program will last, how the program will be evaluated and an explanation of how success of the program is determined, and any other necessary parameters.[235]

i. If such a program is approved, should late fees be waived for qualifying customers?

Staff Position: Staff is not opposed to an assistance program that would waive late fees. Staff requires the full details of a potential program to develop a position and would be happy to do so in the Affordability Docket.[236]

Ray Cunneen

ii. If such program is approved, how should the waived revenues be recovered?

Staff Position: As stated above, Staff recommends the Commission adopt Stipulation IV in its entirety. If the Commission chooses not to adopt this agreement and adopt the OPC's proposal to create a low-income rate or assistance program that waives EMM's customer charge for qualifying customers, Staff proposes that the waived revenue "recovery be treated similarly to the recovery for Economic Development Incentives ("EDI")" with the amount of avoided revenues to be incorporated into the revenues required from all

[235] Ex. 135, Rebuttal Testimony of Tammy Huber, p. 7, lines 10-16.
[236] Staff's Statement of Positions, p. 12.

classes as an equal percentage adjustment to the other-wise applicable class revenue requirement.[237,238]

Alternatively, it may "also be reasonable to treat the avoided revenue as a program expense that is included in the cost of service calculation and remove the revenue from the residential class revenue calculation".[239] In this case, and because Staff does not recommend reliance on a CCOS for class revenue requirement calculations, resolution of this issue would not be necessary.[240]

Andrea B. Hansen

Issue 17. Depreciation
A. Which depreciation rates should be used?

Background: Stipulation I (signed by EMM and Staff) resolves, among other issues in this case, Issue 17 concerning depreciation. OPC, Renew, and Google did not oppose this agreement. While not objecting, MECG did preserve Issue 17.A. for hearing.[241]

The Commission held an evidentiary hearing regarding this issue and others from October 5, 2026, through October 13, 2026. The Commission further held an on-the-record presentation on October 13, 2026, so that the Commission could question the parties about the stipulations and agreements in this case.[242]

The *Partial Stipulation and Agreement* resolves Issue 17, sub-issues B-E of depreciation. In part, the signatories agreed to adopt the depreciation and amortization

[237] Rebuttal Testimony of Sarah Lange, p. 71, lines 7-10.
[238] A description of EDI recovery is located in Rebuttal Testimony of Sarah L.K. Lange, p. 71, lines 11-15.
[239] Rebuttal Testimony of Sarah Lange, page 71, lines 16-19.
[240] Rebuttal Testimony of Sarah Lange, p. 71, Lines 16-19, Highly Confidential.
[241] EFIS Item No. 311 *Partial Stipulation and Agreement*, p. 1.
[242] Case No. ER-2026-0143, *Order Setting on-the-record Presentation*.

rates prepared by staff and reflected in Exhibit C[243]; to adopt the Company's General Plant Amortization in order to appropriately record the adjustment prospectively over the 5-year amortization period; and to exclude the earnings per share ("EPS") portion of short-term incentives capitalized from Plant. The Parties further agree the short-term incentive disallowance will be amortized over 20 years.[244] MECG preserved Issue 17.A. based on MECG witness Brian Andrew's life estimate adjustments. Specifically, Andrew disagrees with the retirement dates of Iatan Unit 1 and La Cygne Unit 2.

Staff Position: Staff supports the approval of Stipulation I and rejects MECG witness Brian Andrew's life estimate adjustments. Pursuant to state regulation, MECG's objection instructs the Commission to treat the *Partial Stipulation and Agreement* and the issues it settles as the signatory parties' stipulated position, without binding those parties, and allows the Commission to decide any remaining issues after the hearing.[245]

Here, Mr. Andrews disagrees with the projected retirement dates of Iatan Unit 1 and La Cygne Unit 2, thus the depreciation rates agreed to in Stipulation I. Brian Andrews recommends that the Commission extend the retirement date used for Iatan Unit 1 from March 2040 to June 2045, and extend the retirement date used for La Cygne Unit 2 and La Cygne Common from March 2040 to June 2045, as provided in EMM's most recent Integrated Resource Plan (IRP).[246]

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[243] EFIS Item No. 328 *Notice of Depreciation and Amortization Rates*, Filed October 13, 2026*;* (Paragraph 12 of the Agreement referenced Exhibit C, which contained erroneous depreciation and amortization rates. Staff and EMM provided *Corrected Exhibit C*).
[244] EFIS Item No. 311 *Partial Stipulation and Agreement,* p. 4-5.
[245] 20 CSR 4240-2.115(2)(D).
[246] Ex. 302, Direct Testimony of Brian Andrews, p. 28, Lines 3-5.

The selection of future service lives for a given account considers analysis of historical data and other factors that could influence the future life of the property along with professional judgment. Staff experts reviewed historical plant, retirement, salvage, and cost of removal data provided by EMM to estimate the average service life for each account.[247] Staff considered the anticipated retirement dates with those used in prior rate cases (ER-2022-0130) and EMM's IRP (EO-2026-0188).[248] Staff's analysis and the resulting depreciation rate schedule is sound. Therefore, the Commission should approve Stipulation I, reject MECG's life estimate adjustments, and adopt the depreciation and amortization rates prepared by staff and reflected in Exhibit C to Stipulation I.[249]

Ray Cunneen

Issue 18. Plant in Service Accounting
B. What amount of PISA deferral should be reflected in rate base?

Staff Position: Using the PISA statute, §393.1400, RSMo, as a guideline, Staff determined this amount. Staff's position is reflected in Exhibit B of Stipulation I. The asset and liability schedule attached to Stipulation I reflects a PISA asset of $216,315,876.

Carolyn H. Kerr

Issue 19. Distribution Investment
A. What level of distribution capital investment should be reflected in rate base?

Staff Position: Staff takes no position on OPC's recommended disallowance.

[247] Ex. 100, Direct Testimony of Amanda Arandia, P. 4, Lines 7-10.
[248] Ex. 100, Direct Testimony of Amanda Arandia, p. 4, footnote 2.
[249] https://efis.psc.mo.gov/Document/Display/892644

B. Is EMM's asset prioritization methodology a reasonable basis for the investment reflected in this case?

Staff Position: Staff cannot conclude whether EMM's asset prioritization methodology is reasonable without access to the underlying analysis.[250] In rebuttal, Mr. Bowman testified that the AssetLens analysis was unavailable for Staff's review.[251] He also testified that EMM did not retain the benefit-cost ratios on which it based its decisions.[252]

Staff, therefore, cannot conclude whether the methodology is reasonable on the material it could review.[253] Staff also did not recommend a disallowance of previous distribution investment.[254] The Commission should not treat the absence of a Staff disallowance recommendation as Staff's endorsement of EMM's methodology.

Eric T. Vandergriff

Issue 20. Rate Base Components

B. What amount of construction work in progress is appropriate to reflect in rate base?

The Commission should not include CWIP in rate base. The statute (393.135, RSMo) authorizing the Commission to include CWIP requires the Commission to establish limitations in a CCN case before it can include CWIP in base rates; that statute (393.135) specifically states, "The commission shall determine, in a proceeding under section 393.170 [the CCN statute], the amount of construction work in progress that may be included in rate base." Due to the timing of the EMM's CCN in Case No. EA-2026-0154 and

[250] Malachi Bowman, hearing testimony, Unofficial Transcript, Volume 9, EFIS Item No. 342, p. 75, at line 8-25.
[251] Malachi Bowman, Rebuttal Testimony, EFIS Item No. 153, p. 11, at line 8-10.
[252] *Id.*, p. 12, at line 1-4.
[253] Malachi Bowman, hearing testimony, Unofficial Transcript, Volume 9, EFIS Item No. 342, p. 75, at line 8-25.
[254] Malachi Bowman, Rebuttal Testimony, EFIS Item No. 153, p. 13, at line 3-8.

the current rate case, the Commission has not yet had the opportunity to determine the amount of CWIP to be included in rates for the 0154 project.[255] Under the plain reading of the statute, the Commission must determine the CWIP to be used in the rate base in the associated CCN proceeding first. It has not done that yet, and so cannot include it in this rate case until it does.

If CWIP is included in rate base, the Commission should not include unsupported amounts from affiliate, Transource Missouri, and should be subject to the overall rate of return ordered by the Commission and set forth in the Staff's Accounting Schedules filed in this case. See also further below, *Staff's Initial Post-Hearing Brief* addressing Issue 32.D: *Rates and Revenue Responsibility – Revenue Apportionment and Implementation – How should revenue responsibility for construction work in progress by assigned or allocated among the customer classes?*

C. How much of EMM's current rate base has been retired, and should a rate of return be applied to this amount?

Mass property or mass assets refer to a large volume of homogeneous, low-cost physical assets that are grouped together for tracking, depreciation, and tax valuation, rather than being accounted for individually, like utility poles, transformers, overhead lines, and smart meters. EMM applies mass asset accounting to this type of property that is large in quantity but small in individual value, the advantage being to avoid complexity of tracking

[255] Young, True-Up Rebuttal, p. 3, Line 20 through p. 4, Line 5.

accumulated depreciation on a large quantity of small -value items by applying a depreciation rate to a plant account instead of individual retirement units.[256]

Between June 1, 2022, and June 30, 2026, EMM retired $160 Million of Missouri-jurisdictional mass property which left a net $50 Million of rate base value as of the true-up date. EMM's current rate base contains an amount related to plant that is no longer in service. It is not equitable to charge ratepayers a rate of return on plant that no longer provides electric service. The Commission should adopt Staff's adjustment to remove retired plant from the rate of return calculation.[257]

E. If construction work in progress is included in rate base, what rate of return should be applied to it?

If CWIP is included in rate base, it should be subject to the overall rate of return ordered by the Commission and set forth in the Staff's Accounting Schedules filed in this case.[258]

F. What amount of transmission investment since EMM's last rate case should be included in rate base?

Staff takes no position at this time but reserves the right to do so in its Reply Brief.

H. Should rate base be reduced to remove Evergy Kansas Central's investment in transmission to serve Panasonic allocated to EMM?

Staff takes no position on this issue, more specifically Staff takes no position on OPC's recommended disallowance, but reserves the right to do so in its Reply Brief.

Carolyn H. Kerr

[256] Young Direct, p. 35, ll. 4-9.
[257] Young Surrebuttal, p. 9, Lines 7-14.
[258] See Staff Accounting Schedules, Schedule 1.

Issue 22. Fuel Adjustment Clause – Structure and Base Factor

A. Should the Commission authorize EMM to continue its FAC?

Staff Position: Yes. Staff recommends the Commission approve, with modifications, the continuation of EMM's FAC. Ms. Stacy Henderson's direct testimony demonstrates the appropriateness of continuing EMM's FAC. Specifically, the charts and discussion that EMM's ANEC continues to be relatively large and volatile.[259]

B. Should the general construct of EMM's FAC be changed?

Staff Position: No. The Commission should retain the existing FAC structure, with modifications necessary to properly address LLPS customers. EMM proposed in rebuttal testimony more substantial changes to the FAC. Staff witness Brooke Mastrogiannis explained that the Company's proposal would fundamentally alter the existing relationship between base rates and the FAC without the information and supporting tariff modifications necessary to evaluate its consequences.[260] Commission rule 20 CSR 4240-20.090(2) requires that when an electric utility wishes to establish, continue, or modify a rate adjustment mechanism, or "RAM", it must raise the issue in its direct testimony, and provide supporting documentation on 19 delineated issues. Not only did EMM fail to raise this issue in its direct testimony, but it also wholly failed to provide the supporting documentation required by the rule. Without this information, the Commission cannot reasonably determine whether the proposed change in structure will produce just and reasonable rates

[259] Direct Testimony of Stacy Henderson, page 7.
[260] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pg. 3-7.

without understanding how it would affect base rates, the accounting and recovery of eligible costs, and the allocation of financial risk between customers and shareholders.

That being said, the subsequent LLPS Stipulation and Agreement entered into by EMM and Google narrows that proposal. Paragraph 6 provides that FAC operations will not be modified because of LLPS customers, subject to the changes described in the agreement. Paragraphs 7 through 10 then establish a different treatment of LLPS costs, incentive sharing, and the FAC base factor.[261] Staff opposes these modifications.

The stipulation would exclude LLPS annualized energy costs and load from the base factor calculation while allowing actual LLPS actual energy costs to flow through the FAC. This creates an inconsistency between the costs reflected in the base factor and the costs included in subsequent accumulation periods. Staff identified this concern in its October 6 objection, explaining that the proposed treatment would permit EMM to recover LLPS energy expenses through the FAC while continuing to collect energy-related charges under its LLPS tariff.[262]

Staff recommends a more consistent approach. Under Staff's Option 1, the FAC would include appropriate LLPS energy consumption and associated expenses in both the normalized calculation and subsequent accumulation periods. Under Staff's Option 2, LLPS customers would be excluded from the FAC to the extent practicable. Either approach addresses the relationship between the costs reflected in the base calculation and the costs recovered through the FAC more directly than the EMM–Google settlement.

[261] Stipulation V (LLPS), paragraphs 6–10.
[262] Staff Objection to Stipulation V (LLPS), paragraphs 7–9

As further discussed in Issue 22.C, the [EMM/Google stip] sets out a base factor of $0.01742 per kWh, much lower than Staff's proposed FAC Option 1 of $0.02030 per kWh or FAC Option 2 of $0.01901 per kWh. Staff's FAC Option 1 or FAC Option 2 base factors must be appropriately paired with the Commission's decision on whether LLPS is included or excluded from the FAC.

As such, EMM's recommendations pertaining to a change in the construct of its FAC should be disregarded.[263]

C. At what value should the FAC Base Factor be set at the conclusion of this case?

Staff Position: The Commission should adopt the base factor calculated by Staff, consistent with its determination concerning the treatment of LLPS customers. Staff witness Brooke Mastrogiannis calculated a true-up base factor rate for FAC Option 1 of $0.02030 per kWh, which would include large load customers in the FAC (Customer A) with an annualized load and estimated annualized energy expenses. Staff calculated the true-up base factor for FAC Option 2 of $0.01901, which does not include any large load customers (Customer A).[264] Ms. Mastrogiannis provided these values using normalized net system inputs and Staff's net fuel and purchased power costs, updated through the June 30, 2026, true-up period.[265] Although either could provide a reasonable outcome, Mastrogiannis explained that Staff prefers Option 2 because it requires fewer assumptions concerning the consumption and costs attributable to large-load customers.[266]

[263] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pgs. 5-7.
[264] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pg. 19, ll. 1-13.
[265] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, at pg. 18, line 12 through pg. 19, line 13.
[266] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pg. 2, line 17 through pg. 3, line 2.

EMM originally recommended a base factor of $0.01931 per kWh. However, its subsequent settlement with Google proposes a factor of $0.01742 per kWh.[267] Paragraph 9 excludes LLPS fuel costs from the base factor calculation while requiring that those costs flow through the FAC as actual net energy costs. Paragraph 10 then relies upon Staff's fuel model and net system inputs to calculate the proposed $0.01742 factor.[268]

Staff objects because the resulting calculation does not use the same assumptions as either of Staff's recommended alternatives.

As Staff explained in its October 6 objection, using selected inputs from Staff's model does not establish that the resulting base factor represents Staff's recommended calculation. The appropriate factor depends upon the scope and operation of the FAC in which it will be used.[269]

Should the Commission adopt either FAC option 1 or 2, Staff asks the Commission to include the appropriate true-up base factor as calculated by Staff.

D. What sharing ratio between EMM and its customers should the Commission order as an incentive mechanism in EMM's FAC?

Staff Position: The Commission should retain the existing 95%/5% sharing mechanism. EMM proposed in rebuttal testimony a change to the FAC sharing mechanism from 95%/5% to 100%/0%. Staff filed testimony in opposition to this proposal.[270] However, as part of the LLPS Stipulation and Agreement between EMM and Google, they propose to

[267] Stipulation V (LLPS), paragraph 10; EMM's Statement of Positions pg. 21.
[268] Stipulation V (LLPS), paragraphs 9–10.
[269] Staff Objection to LLPS Partial Stipulation and Agreement, *supra* note 6, paragraphs 7–9.
[270] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pgs. 8-14.

keep the sharing mechanism at 95%/5% for the non-LLPS portion,[271] which is consistent with Staff's position, and consistent with the sharing mechanism for all other utilities. However, the LLPS portion would be subject to 90%/10% sharing. The resulting customer-responsibility amounts would then be combined to establish the FAC rate.[272]

Staff does not dispute that applying a 90% sharing percentage to part of the incremental FAC balance could increase the Company's financial participation in that balance.

The relevant question, however, is whether that adjustment adequately addresses the broader concerns created by excluding LLPS costs from the base factor while including those costs during accumulation periods.

It does not.

Staff asks that the Commission reject the settlement's proposed sharing modification and order the current sharing mechanism not be changed.

Douglas W. Hennon

Issue 23. Fuel Adjustment Clause – Included Costs

A. What SPP transmission costs should be included in the FAC?

Staff Position: Staff witness Brooke Mastrogiannis calculated the pass-through percentage of SPP transmission costs at 31.8%.[273] EMM initially proposed a percentage of 27.78%. However, EMM and Google have agreed to use Staff's recommended percentage in their LLPS Partial Stipulation and Agreement which was filed on October 5, 2026

[271] Stipulation V (LLPS), paragraph 7.
[272] Id.
[273] Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pg. 20, l. 2.

(Stipulation V).[274] While Staff objected to several provisions of Stipulation V, Staff did not oppose the transmission cost provision. However, Staff's support for the agreed transmission percentage should not be construed as support for the remaining FAC provisions of the EMM–Google settlement.

The Commission should adopt the 31.8% transmission percentage as an independent determination supported by Staff's calculation.

C. What FAC subaccounts should be included in the FAC?

Staff Position: There are several subaccounts that are listed as to either be included or not be included in the FAC. In Stipulation I the parties agree on most of these issues.[275] However, Staff does oppose FAC subaccounts 447016 and 555006. This ties directly into issue 23D.

D. Should EMM include long-term capacity purchases and sales for recovery in its FAC?

Staff Position: Staff objects to the inclusion of the subaccounts identified in paragraph 11 of Stipulation V (LLPS) as improper. EMM's long term capacity sales will fall off after the expected rates of this case, and EMM will add in long term capacity purchases after the expected rates of this case. If only one aspect is added in the base factor it is disproportionate to the reality of expected long-term capacity in the future.[276]

It is Staff's position that these two accounts should not be included in the FAC, as it appears these long-term capacity and sales specifically relate to large load customers.

[274] Stipulation V (LLPS), paragraph 12.
[275] Stipulation I (Auditing), paragraph 15
[276] Official Tr., Vol. 7, pgs. 252-253

EMM has provided a projected increase in customer demand through 2028.[277] It appears to Staff that a majority of the volume in capacity purchases is based on an estimate of what EMM expects to pay for capacity specific to large load customers, and if the projected increase in demand is due to large load customers, those customers should be paying for the capacity they need.

The large load tariff case[278] includes a provision for Interim Capacity which addresses this. The provision provides that if EMM determines that that a customer's load cannot be serviced by EMM's existing capabilities, then they may enter into specific market contract agreements to provide for the necessary capacity requirements of the specific customer until sufficient capacity may be supplied. The provision also states that customers shall be subject to an additional demand charge calculated according to the terms of the Interim Capacity Agreement, with the customer responsible for the full costs thereof. If EMM does not prudently pursue recovery through an LLPS interim capacity charge, then EMM's failure to recover should not be borne by EMM legacy ratepayers.

Staff has proposed that EMM be required to provide electric service agreements, (ESAs) and capacity and demand forecasts both with and without LLPS customers.[279] These issues are more fully addressed in the portion of this brief on Issue 31. If this recommendation was approved by the Commission, then it would help clarify whether EMM's capacity and demand forecasts required more capacity to serve its large load customers.

[277] Rebuttal Testimony of Brooke Mastrogiannis, pg. 2, line 18 through pg. 3, line 5.
[278] EO-2025-0154, Non-Unanimous Global Stipulation filed on September 25, 2025, page 9.
[279] Direct Testimony of Claire Eubanks, pg.12, lines 10-13; pgs. 17, line 3 through pg. 18, line 7

It is Staff's position that if the additional projected capacity volumes are driven by large load customers, the cost of those contracts should be borne by those customers. Further, inclusion of long-term capacity contracts in the FAC related to load growth would result in double-recovery through the existing rates for service.

Staff's recommendation is consistent with the approach taken by Ameren Missouri. In Ameren Missouri's Direct testimony in Case No. ER-2026-0291 they state: "Under the large load tariff, the cost of interim capacity is to be paid by the large load customer pursuant to an additional demand charge as part of their electric service bill, and including those same costs in the FAC would negatively impact existing customers and result in the double recovery of capacity costs".

Douglas W. Hennon

Issue 25: Fuel Adjustment Clause – Large Load Power Service

History and Operation of Missouri Fuel Adjustment Clause

The Fuel Adjustment Clause ("FAC") allows an electric utility to adjust what it charges customers for certain electricity-supply costs without having to file a new general rate case every time those costs change. It is authorized under § 386.266.1, RSMo., and implemented through Commission Rule 20 CSR 4240-20.090.

For EMM, these costs include more than the fuel burned at power plants. They also include certain costs of purchasing electricity, associated wholesale-market transactions, and revenues from selling electricity.

The underlying idea is that electricity-supply costs fluctuate much more frequently than the rates approved in a traditional rate case. For example, EMM operates a variety

of generation assets which burn coal, use nuclear fuel, or use natural gas. EMM also participates in a regional wholesale electricity market operated by the Southwest Power Pool ("SPP").

The costs and revenues discussed above together are referred to as Net Base Energy Costs ("NBEC"). In a general rate case, these costs and revenues are estimated, based on a normalized or annualized level as of the update period and revised again at true-up. The base factor is calculated as the NBEC divided by the Net System Input ("NSI"). NSI is an estimate of the normalized amount of electricity required to meet the energy demands of both the company's customers and its own needs at the generation level. During a rate case, with proper information, the relationship of the FAC base factor and permanent rates can be aligned. The base factor then gets used in the subsequent Fuel Adjustment Rate ("FAR") filings, and it calculates the difference between the actual net energy costs ("ANEC") and the NBEC.

For example, assume the Commission approves electric rates assuming it will cost EMM $100 million annually, net of certain revenues, to produce and purchase electricity. The $100 million dollars would be considered the NBEC and is based upon the NSI included in the determination of fuel and purchased power expense during the test period used to determine the revenue requirement. Following the Commission's order, coal prices increase, natural gas becomes more expensive, and wholesale electricity prices change, resulting in EMM's actual net energy costs being $150 million. Without an FAC, EMM would have to absorb that additional $50 million expense until it could seek recovery through another permissible ratemaking process. With an FAC, EMM can recover an authorized

portion of the difference between the net base energy costs and the actual net energy costs through a separate charge on customers' bills. A key point to highlight: the process works in both directions. If actual net energy costs are lower than the amount reflected in base rates, customers receive the applicable portion of the benefit through a lower FAC charge.

A common misunderstanding of the FAC is that it is the only way a utility like EMM recovers all of its fuel costs; this is not accurate. Customers already pay for an expected level of fuel and purchases power costs through their regular electricity rates based upon the energy consumption reflected in the calculation of net fuel and purchased power expense in the revenue requirement. The FAC generally adjusts for the difference between that expected level and actual eligible net energy costs.

In a general rate case like this one, the Commission sets new base rates and establishes the level of eligible net energy costs to be reflected in those rates; in essence, the Commission is rebasing those costs. The new base rates will incorporate those eligible net energy costs, and future FAC adjustments will measure eligible differences relative to the newly approved base factor and the actual net energy costs. The base factor only represents the fuel and purchased power expense of the energy consumed during the test period in the rate case.

Introduction

The Commission should adopt Staff's Option 2, which removes LLPS customers and its energy and transmission expenses attributable to their service from EMM's FAC base factor calculation and future FAC fuel adjustment rate ("FAR") filings. Alternatively, the Commission should adopt Staff's Option 1 as a complete package: retain LLPS customers

in the FAC and adjust the base factor to recognize the associated annualized energy and expense. The Commission should order Staff's additional reporting under either approach.

The Commission should reject the hybrid option in the LLPS Agreement because it excludes LLPS load and expense from the base-factor calculation but includes LLPS expense in actual net energy cost going forward. This mismatches the FAC base factor calculation and what is included in the FAC FAR going forward, which will cause EMM to under-recover a substantially higher amount between rate cases which will later be recovered from all ratepayers through the FAR. It exposes non-LLPS customers to the cost of serving new LLPS load while EMM also receives the retail revenues generated by that load. However, an increased shareholder sharing percentage,[280] applied to a prorated portion of net FAC differences, does not correct the underlying mismatch. Said another way, the LLPS agreement does not reflect LLPS load in the net base energy cost, but will result in all ratepayers paying the increases in costs through the FAR.

Staff offers two reasonable alternatives, rather than demand that the Commission choose one particular option that mismatches large load and its related load and expense. Its surrebuttal identifies Option 2 as preferable because it depends less on assumptions about Customer A's annualized consumption.[281] The Commission should preserve that distinction: Option 2 is Staff's preferred disposition, while Option 1 remains an acceptable alternative.

[280] The LLPS Agreement offers a 90/10 sharing percentage that is explained more later in this initial brief.
[281] Exhibit 156, Surrebuttal/True-Up Direct Testimony of Brooke Mastrogiannis, pp. 2-3.

Section 386.266.1, RSMo, authorizes periodic adjustments for changes in prudently incurred fuel and purchased-power costs, including transportation. Subsections 5 and 6 permit the Commission to approve, modify, reject, or discontinue an adjustment mechanism through the prescribed general-rate or complaint proceeding. The statute requires consideration of all relevant factors, an opportunity to earn a fair return, annual reconciliation, and periodic prudence review. These requirements do not make an existing allocation method permanent or require automatic recovery of every claimed cost through the FAC.

The Commission must also apply § 393.130.1 and .3, RSMo, which require reasonable charges and prohibit undue preferences and disadvantages. Section 393.130.7 specifically directs large-load tariffs to reflect a representative share of service costs and protect other classes against unjust or unreasonable costs arising from service to large customers. The FAC must be evaluated together with the LLPS tariff to give that protection practical effect. EMM bears the burden of proving its proposed increased rates are reasonable, pursuant to § 393.150.2, RSMo.

Commission Rule 20 CSR 4240-20.090(2) requires rebasing of base energy costs in a general rate proceeding in which an FAC is continued or modified. The accompanying supporting-information requirements reinforce the need to evaluate the design, intended operation, and tariff language together. The Commission should select a coherent mechanism supported by the record, rather than pair the starting point of one approach with the recovery provisions of another.

In EMM's LLPS tariff case, Case No. EO-2025-0154, the Commission reserved FAC modification for a general rate case and declined to require separate commercial pricing nodes.[282] This proceeding provides the required forum. Staff considered the Commission's order in developing its recommendation in this case and offers Option 2 as an alternative method of separating LLPS costs and revenues from the FAC.[283] Staff's current proposal also uses EMM's existing load node; it does not depend on obtaining separate LLPS settlement nodes from SPP.[284]

A. Should changes be made to the FAC to address LLPS customers?

The FAC compares actual net energy costs against the base energy costs recognized in the revenue requirement from base rates. Its operation depends on a reasonable relationship between the costs, sales determinants, and revenues reflected at the starting point and those subsequently reconciled. Staff witness Brooke Mastrogiannis explains that an understated base factor can produce larger subsequent fuel adjustment rates ("FARs"), particularly when substantial new load is served after the underlying rate-case snapshot and not incorporated into the FAC base factor calculation.[285]

The concern is not simply that new customers consume energy; they also pay retail energy, demand, and other charges as their operations expand. If the FAC recognizes additional supply expense without appropriately accounting for the corresponding retail recovery, EMM can receive the benefit of load-growth revenues while distributing additional

[282] Case No. EO-2025-0154, Report and Order, pp. 40-42 (November 13, 2025).
[283] Exhibit 123, Notice of Corrected Testimony of Claire M. Eubanks, PE, p. 8.
[284] Exhibit 111, Direct Testimony of Brooke Mastrogiannis, pp. 10-11; see also Exhibit 167, Surrebuttal/True-Up Direct Testimony of Sarah L.K. Lange, pp. 9-11.
[285] Ex. 111, pp. 3-7.

energy expense through the common rider. Ms. Lange's analysis addresses this interaction, rather than treating incremental revenues and incremental costs in isolation.[286]

Ms. Lange examined available April–June 2026 hourly LLPS load and day-ahead energy values, together with the associated AP 22 FAR calculation. Her analysis identifies positive regulatory lag from energy charges alone and excludes the additional revenues associated with demand, grid, and customer charges.[287] Her illustrative Option 2 calculation would lower the AP 22 FAR by approximately $0.00028 per kWh; because that period produced an overall credit, the adjustment would increase the credit. That illustration covers hourly energy expense and does not quantify all additional benefits of the monthly load-side adjustments.[288]

Staff does not claim that every future month will reproduce that relationship. Nor does it claim that fixed tariff rates guarantee a perfect hedge against future market prices. The point is that the common FAC can transfer a portion of LLPS-related expense to other customers while growth revenues remain with EMM. Observed results make that concern concrete. Uncertainty over its future magnitude is a reason to adopt a more reliable mechanism, not a reason to disregard it.

I. Staff Option 2 provides the stronger protection and can be implemented using existing data.

Under Staff Option 2, LLPS customers are exempt from the common FAC and the major incremental energy and transmission expenses associated with those customers

[286] Exhibit 138, Rebuttal Testimony of Sarah L.K. Lange, pp. 24-26; see also Ex. 167, pp. 4-8.
[287] Ex. 167, pp. 5-8.
[288] *Id*, p. 7.

are removed from the common base factor calculation and future FAR filings. Staff initially described the base-factor adjustment as recognizing the difference between Customer B load at the update and true-up cutoffs.[289] By Staff's true-up filing, the fuel model already included annualized Customer B load and excluded Customer A, so no further Option 2 base-factor adjustment was required on that account.[290]

Customer B must not be confused with the LLPS class. Ms. Mastrogiannis specifically explains that Customer B was taking service under LPS rates and would remain in the FAC under Staff's recommendation. Option 2 follows the applicable service classification; it does not exempt every customer described in the record as a large load.[291]

Staff identifies three principal deductions from Missouri-jurisdictional FAC expense. First, EMM calculates the hourly LLPS energy amount using each LLPS customer's hourly load and the settled day-ahead locational marginal price ("LMP") at the existing EMM load node. Second, it prorates load-side, energy-based SPP transactions using LLPS monthly energy relative to Missouri-jurisdictional monthly energy. Third, it prorates load-side, demand-based SPP transactions using LLPS demand coincident with the relevant jurisdictional demand determinant.[292]

Implementation should align the load and price units, applicable losses, jurisdictional treatment, and billing determinants. The approved tariff and supporting calculations should remove the LLPS amounts consistently from the cost and sales

[289] Ex. 111, pp. 9-12.
[290] Ex. 156, p. 18, ll. 11-18.
[291] Ex. 111, p. 12, ll. 5-11.
[292] Ex. 111, pp. 11-12 and Ex. 167, pp. 9-11.

components in the FAC to which the exemption applies. These implementation requirements preserve the symmetry of Staff's recommendation; they do not authorize a new deduction or recovery category.

II. The integrated-system objections.

EMM and Google argue that the system is centrally dispatched, that generation revenues offset wholesale purchases, and that the cost of serving customers is predominantly the cost of operating EMM's own fleet; Google witness Dr. Berry therefore objects to assigning day-ahead LMP values to LLPS while using production-cost modeling for other customers.[293] EMM witness Darrin Ives maintains that individual-customer fuel-cost separation is infeasible and that Staff's proposal assigns system-level expenses through proxies.[294] EMM witness J.P. Meitner likewise disputes monthly energy-based allocation of integrated SPP charges.[295] These arguments ignore the reality of participation in the SPP integrated market. Each Megawatt hour of energy used by EMM ratepayers is purchased at the LMP price of the EMM load node.[296]

EMM and Google's objections do not establish that all LLPS-related expense must remain in the FAC. Staff does not propose assigning a particular generator to Customer A, changing SPP dispatch, or registering a separate commercial pricing node; Staff allocates the value of load-side transactions at the existing EMM node by actual hourly LLPS load, with

[293] Exhibit 452, Rebuttal Testimony of Dr. Carolyn Berry, pp. 7-11.
[294] Exhibit 30, Darrin R. Ives Rebuttal Testimony, pp. 4-7.
[295] Exhibit 63, JP Meitner Rebuttal Testimony, pp. 8-9.
[296] Ex. 177, p. 51, ll. 3-21.

separate treatment of energy-based and demand-based charges.[297] Aggregate settlement and retail allocation answer different questions. The former does not eliminate the latter.

Google witness Dr. Berry recognizes that EMM sells its generated energy and buys the energy needed for load through SPP markets at LMPs.[298] Staff accepts the importance of generation costs and revenues to total-company net energy cost. Its proposal addresses how the expense associated with the expanding LLPS class should be separated for the retail FAC or alternatively reflect the costs within the calculation of the FAC base factor (i.e. Option 1 discussed below). The Commission can preserve integrated system operation while declining to socialize the principal load-side expenses of that class through the FAC.

EMM witness Hsin Foo's production-cost testimony reinforces the need to keep distinct issues distinct. Her true-up direct identifies updated coal prices, gas prices, and net system input as model inputs, and explains how changed prices alter dispatch and market purchases.[299] That evidence supports normalization; it does not show that a modeled annual total can eliminate uncertainty about the hourly shape of a customer still ramping operations. Ms. Mastrogiannis explains why Staff could use an annualized load-factor estimate for Option 1 without treating that estimate as a reliable hourly load shape for production-cost modeling.[300]

[297] Ex. 167, pp. 10-11.
[298] Ex. 452, p. 7, ll. 3-17.
[299] True-Up Direct Testimony of Hsin Foo, EFIS Item 226, pp. 2-3 (no exhibit number for Foo's true-up direct testimony in the 3rd Updated Exhibit List of EMM).
[300] Ex. 156, p. 18, ll. 1-10.

Ms. Foo also criticizes the use of generalized demand and energy ratios.[301] Staff's response is more specific than that characterization: use actual hourly load for energy, monthly energy for energy-billed charges, and coincident demand for demand-billed charges.[302]

The Commission should require transparency about those determinants and exclude generation-side transactions from the load-side proration. A disagreement over the precision of allocation warrants disciplined reporting, not an assumption that no defensible allocation is possible.

III. Option 1 remains a reasonable alternative if the Commission retains LLPS customers in the FAC.

If the Commission retains LLPS customers in the existing FAC, it should adopt Staff's Option 1 with the corresponding load and expense adjustments in the FAC base factor calculation. Ms. Lange calculated incremental day-ahead expense using Staff's true-up market prices and an annualized consumption assumption. The adjustment adds both annualized expense to the Missouri-jurisdictional numerator and annualized energy to the denominator.[303] Staff's September true-up recommendation produces a base factor of $0.02030 per kWh for Option 1, compared with $0.01901 per kWh for Option 2.[304]

Those are alternative options for treatment in the FAC, not interchangeable dollar figures. The Commission should use the base factor belonging to its selected treatment of

[301] Exhibit 16, Hsin Foo Rebuttal Testimony, p. 23, ll. 10-19.
[302] Ex. 167, pp. 9-10.
[303] *Id*, pp. 43-44.
[304] Ex. 156, p. 19.

large load customers and maintain consistency with its final determinations on recoverable costs. Option 1 protects other customers against the level of LLPS growth reflected in its annualized calculation; it does not fully insulate them from later growth beyond that level.[305]

EMM witness Linda Nunn objects that Staff annualizes revenues while declining to model all associated costs, and emphasizes that LLPS energy charges recover more than fuel alone.[306] Staff agrees that consistency matters. That is precisely why Option 1 adds both the associated energy and expense in both the base factor calculation and future FAR, and why Option 2 removes both the class and the principal related expenses from the common FAC FAR rider and base factor calculation. Neither approach rests on a claim that all retail energy revenue is permanently identical to hourly market cost. Ms. Nunn's criticism does not justify including LLPS expense in actual net energy cost while excluding its contribution from the base-factor calculation. In fact, the LLPS Agreement fails to include the associated costs of Customer A in the calculation of the FAC base factor while allowing for costs increases in future periods to be recovered through the FAR.

IV. Flaws in the LLPS Agreement.

Google and EMM propose to leave LLPS in the FAC, exclude LLPS fuel costs from the base-factor calculation, and permit those costs to enter actual net energy cost. They propose a $0.01742 per kWh base factor which reflects long-term capacity purchase and sales subaccounts. Staff's objection identifies why those elements do not implement either of Staff's alternatives.

[305] Ex. 111, p. 10, ll. 1-10; *see also* Ex. 167, pp. 18-19.
[306] Exhibit 72, Linda J. Nunn Rebuttal Testimony of, pp. 3-7.

Mr. Ives confirmed the distinction at the October 13 on-the-record presentation. He explained that the stipulated factor does not use LLPS net system input or cost, instead it uses the components from Staff's runs with adjustments for long-term capacity transactions, and maintains LLPS inclusion in the FAC.[307] His general assertion that there is no double recovery because LLPS customers are also paying for any adjustment that flows through due to changes in net fuel and purchased power by participating in the FAC must be assessed against that specific design.[308] Staff's objection is to the absence of alignment in the proposed starting point, not to the abstract proposition that a correctly matched FAC reconciles against base costs.

The LLPS Agreement settlement's 90/10 treatment is also narrower than a promise that EMM will absorb ten percent of all incremental LLPS service costs. Paragraph 7 of the LLPS Agreement first allocates the net FAC difference and applies a ratio using the LLPS kWh over total NSI, then applies the different sharing percentage to that allocated net FAC difference, and combines the results into one FAR. Ives described that operation at the on-the-record presentation.[309]

The 90%/10% LLPS sharing mechanism does not provide real value for ratepayers. The 10% share would not be calculated as the total cost of energy for the LLPS class, or the difference between the energy expense included in the FAC base factor and that actually incurred. Instead, it would simply be a prorated share of the accumulated NET energy expense. At a 50 percent LLPS share over total NSI, customers bear 92.5 percent and

[307] Unofficial Tr. Vol. 12 (Public), p. 96.
[308] *Id*, pp. 73-74.
[309] Id, p. 75.

EMM bears 7.5 percent. The five-percentage-point change applies only to the LLPS allocation of the net difference. It does not establish a separate LLPS cost account or remove LLPS-related expense from the common FAR.[310] A larger shareholder share may reduce a charge, but it cannot establish that the remaining charge belongs to the customers that caused it. As shown in the example within Attachment A to the *Staff Objection to LLPS Partial Stipulation and Agreement*, the change for LLPS customers from a 95/5 to 90/10 sharing ratio for LLPS customers results in only $5,000 extra EMM is contributing for LLPS customers.[311]

Long-term capacity eligibility is separately listed elsewhere in the case. For present purposes, adding capacity subaccounts does not cure the LLPS energy mismatch. Ms. Nunn says customer-specific interim capacity would remain excluded to avoid duplicate recovery but there is no commitment from the Company to ensure that.[312] Staff's concern also encompasses demand-charge revenue and the loss of wholesale capacity sales as capacity is redirected to growing retail load.[313] The Commission should preserve a coherent treatment across the related issues without using this issue to authorize a general expansion of FAC eligibility.

B. What new FAC reporting requirements should the Commission order?

I. <u>Require the hourly and monthly data needed to implement and audit LLPS treatment.</u>

The Commission should order EMM to provide each LLPS customer's hourly load and the settled day-ahead LMP at the EMM load node for each corresponding hour. For the SPP

[310] See Exhibit 2 from the On-the-Record Presentation, Attachment A to the Staff Objection to LLPS Partial Stipulation and Agreement, October 13, 2026.
[311] *Id*.
[312] Exhibit 74, Linda J. Nunn True-Up Rebuttal Testimony, p. 8.
[313] Exhibit 142, Rebuttal Testimony of Brooke Mastrogiannis, pp. 6-8.

energy-based transactions, it should also require total LLPS energy per calendar month and the total EMM Missouri-jurisdictional energy for each calendar month, together with the SPP charges calculated on monthly energy usage without regard to generation sold. For the load-side of SPP demand-based transactions, EMM should provide LLPS demand for each calendar month coincident with the total and applicable Missouri-jurisdictional demand per calendar month and the total SPP charges calculated on EMM's demand per calendar month, without regard to generation sold.[314]

The reporting[315] has value even if the Commission adopts Option 1 or a separate LLPS FAC. It allows Staff to test the reasonableness of annualized assumptions, monitor actual growth, and determine whether costs and sales determinants continue to be treated consistently. A decision to retain integrated recovery should not make the effects of LLPS growth unobservable. OPC witness Angela Schaben likewise supports imposition of Staff's additional reporting if the FAC continues.[316]

II. Require separate CHILLS tracking and prompt notice.

The Commission should require separate monthly tracking and reporting to Staff of all SPP costs related to future Conditional High Impact Large Load Service ("CHILLS") customers. If an EMM customer becomes a CHILLS customer, EMM should notify Staff within three business days and provide a copy of its filing to SPP or FERC.[317]

[314] Ex. 111, p. 11, ll. 12-25.
[315] This FAC reporting is separate from the LLPS reporting recommended by Ms. Eubanks in her direct testimony. FAC reporting as recommended by Stacy Henderson and Krishna Poudel was resolved in the Partial Stipulation between Staff and EMM. If the Commission does not approve the Partial Stipulation it should order the FAC reporting recommended by Staff witnesses.
[316] Exhibit 219, Angela Schaben Surrebuttal Testimony, p. 20, ll. 10-22.
[317] Exhibit 125, Staff Rate Design Report, p. 49, ll. 16-20.

The same report explains Staff's understanding that CHILLS service carries transmission-related responsibilities that must be distinguished from ordinary FAC recovery.[318] Separate tracking and prompt notice will allow Staff to examine the service arrangement when it begins, rather than discover it after costs have entered an accumulation period.

III. Require comparable reporting for the identified capacity and energy contract.

EMM should include in its monthly FAC report, tab 5(K)2, the specific details of the confidential capacity and energy contract identified in Ms. Mastrogiannis' rebuttal, comparable to the information supplied for other power purchase agreements in that tab.[319]

Ms. Mastrogiannis identifies concerns about the capacity pricing basis, accreditation risk, and energy price, and explains that Staff was pursuing discovery.[320] That evidence supports ongoing visibility into the contract; it is not a request to decide prudence in advance. Requiring comparable information for comparable transactions supplies a practical basis for subsequent review.

C. Should EMM have a separate FAC base factor for LLPS customers?

Staff's preferred outcome is Option 2. Its alternative is Option 1. Staff did not initially propose a third mechanism, but Ms. Mastrogiannis states that Staff does not oppose separate FACs as an alternative, provided the supporting reporting is required.[321]

[318] *Id*, ll. 8-15.
[319] Ex. 142, p. 12, ll. 7-12.
[320] *Id*, pp. 10-12.
[321] *Id*, pp. 8-10.

OPC likewise recommends exclusion of LLPS from the common FAC or, alternatively, a separate LLPS class factor to prevent cross-subsidization.[322]

If the Commission chooses a separate LLPS FAC, it must actually separate the class's reconciled expense and recovery. Assigning two labels to portions of a common net difference and recombining them into one FAR does not accomplish that purpose. The LLPS factor should reflect LLPS energy expense and a reasonable proration of FAC-recoverable transmission expense. It should exclude fuel expense for EMM generation and the revenues produced by selling that generation, together with the generation-related ancillary-service and transmission revenues identified by Ms. Lange.[323]

That treatment is symmetrical. The LLPS mechanism would recover the load-side expense identified for that class without also allocating it the cost and revenue streams associated with generation excluded from that mechanism. Meitner argues instead that a separate factor should use the same production-cost methodology as other customers.[324] The Commission should reject an approach that preserves the disputed common-system allocation inside a nominally separate factor. The numerator, sales denominator, and subsequent reconciliation must all correspond to the adopted class-specific treatment.

Ms. Lange's rebuttal testimony calculated an illustrative LLPS-only factor of $0.030965 per kWh. She expressly stated that she could not calculate LLPS responsibility for real-time variations and required ancillary services from the available information.[325]

[322] Ex. 219, p. 20, ll. 14-21.
[323] Ex. 138, p. 28, ll. 4-15.
[324] Exhibit 65, JP Meitner Surrebuttal Testimony, pp. 6-7.
[325] Ex. 138, p. 27, ll. 13-21.

The Commission should treat that number as a supported rebuttal calculation with stated limitations, not a fully trued-up final tariff factor. If it selects this alternative, it should require a compliance calculation using its final cost determinations, the matched LLPS sales determinants, and explicit treatment of those limitations.[326]

The absence of a separate commercial pricing node does not justify silently filling data gaps with unrelated costs or revenues. It requires the Commission to define the allocation it approves and the reports that will permit review. If the Commission concludes that the record does not support the additional determinations needed for a separate mechanism, Staff's Option 2 supplies the more developed and preferred alternative.

Conclusion

The Commission should adopt Staff's Option 2 and the associated reporting. Alternatively, it should adopt Staff's Option 1 in full. It should reject the proposed mismatched combination of an LLPS-excluding base factor and LLPS-including actual expense, and should not treat the proposed 90/10 sharing adjustment as a substitute for correcting that mismatch. Any separate LLPS FAC should contain only the matching LLPS energy and reasonably prorated recoverable transmission components, supported by transparent compliance calculations and ongoing reporting.

Travis J. Pringle

[326] Ex. 142, p. 10, ll. 1-3.

Issue 28 Residential Rate Design

B. Should EMM be required to inform customers on specified Time-of-Use rate schedules of billing issues and remove customers from such specified rate schedules if EMM has estimated their monthly billing?

Although this issue was not attributed to any specific proposed settlement offered during this case, it became moot because of the associated settlement of Issue 27 by Stipulation I (Auditing). As a result, it was not included in the amended list of issues filed with the Commission on October 5, 2026,[327] and does not need to be addressed at this time in this case.

Tracy D. Johnson

Issue 29. Non-Residential Rate Design

A. Should the rates of the non-residential non-lighting customers be restructured in this case?

i. What are the appropriate periods for each time-related element?

ii. Should the Large General Service ("LGS") and Medium General Service ("MGS") classes be subject to reactive demand charges?

iii. What are the appropriate charges for each rate element for each class?

iv. Should EMM be ordered to promptly conduct a billing determinants and customer impact study?

v. What customer education is appropriate?

vi. What date should restructured rates take effect?

B. Should the non-residential non-lighting opt-in time based rates proposed by EMM be implemented?

Issue 29(A) Staff is Generally Supportive of EMM's Proposed Restructuring for Non-Residential Non-Lighting Customers.

Staff is generally in support of EMM's proposed restructuring – with some modifications.[328] Staff's support for EMM's restructuring (as modified by Staff) is to give EMM the opportunity to promptly begin work on the Customer Migration and Determinants

[327] Docket Item No. 315.

[328] Staff Rate Design Report, page 24, line 8.

Study,[329] which is discussed below in Issue 29(A)(iv). Taking time to ensure a smooth transition is essential to mitigate risk. As clarified by Ms. Lange in hearing, Staff's recommended delay in rate restructuring to November 1, 2027, does ***not*** mean EMM will not get a rate increase until November 1, 2027.[330] As stated by Ms. Lange in hearing, Staff's recommendation is to increase rates based on the current structures starting on January 2, 2027.[331]

Issue 29(A)(i) Appropriate Periods for Each Time-Related Element in EMM's Proposed Restructuring.

In one of the attachments to Staff's objection to (Docket Item No. 313), Staff stated the following:

> Staff recommends that customer migrations be established using the highest 15 minute interval demand of the customers as it coincides with the on-peak demand period for summer demand in EMM's direct filing, and the period for winter demand set out in [Docket Item No. 313] which begins at 7:00 am. [332]

As discussed, Staff objects to (Docket Item No. 313). However, Staff indicated in hearing that its flexibility regarding the issue of on-peak demand time period is for the purpose of EMM promptly conducting a Customer Migration and Determinants Study.[333]

[329] Docket Item No. 322, page 1.
[330] Unofficial Transcript, Volume 12, PDF page 163.
[331] Unofficial Transcript, Volume 12, PDF page 163 – 164.
[332] Docket Item No. 322, Staff's Demonstrative Exhibit 5 from the On-the-Record presentation on October 13, 2026.
[333] Unofficial Transcripts, Volume 12, PDF page 193.

Issue 29(A)(ii) The Large General Service ("LGS") and Medium General Service ("MGS") Rate Classes Should be Subject to Reactive Demand Charges.

In (Docket Item No. 313), EMM and MECG agree to remove reactive demand from the MGS and LGS rate classes.[334] Staff disagrees for the reasons discussed below.

Staff recommends the Commission order LGS and MGS rate classes to be subject to reactive demand charges. This is necessary because, as the regional generation fleet changes, there will be an increased need for investment in order to address the reactive demand requirements brought about by these changes to the regional generation fleet.[335]

In general, Staff recommends the application of a system average rate increase "to the reactive demand charges currently tariffed by EMM. Staff calculated annualized and normalized reactive demand charge revenue from the rates as currently structured as $644,648 per year."[336] In light of EMM's proposal to change demand measurement from 30-minute increments to 15-minute increments,[337] Staff recommends that the applicable EMM tariff language defining the applicability of the reactive demand rate be revised from:

> Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.xx per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.[338]

[334] Docket Item No. 313, page 2.
[335] Rebuttal Testimony of Sarah Lange, page 68, lines 18-19.
[336] Staff Rate Design Report, page 33, lines 8-11.
[337] Direct Testimony of Graham A. Jaynes, page 16, lines 19-21.
[338] Staff Rate Design Report, page 33, line 16 – page 34, line 1.

To the following:

> Company shall determine the customer's monthly maximum 15-minute reactive demand in kilovars. In each month a charge of $0.xx per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's highest 15-minute demand occurring at any time in that month.[339]

This modified tariff language changes the computation of reactive demand (measured in kilovars (kV)) and relative customer demand (measured in kW) to a 15-minute basis instead of a 30-minute basis.[340] The modified language proposed by Staff results "in a change in the determinants for the charge."[341] As discussed above, Staff recommends that EMM conduct a Customer Migration and Determinants Study. Once EMM has completed this study, Staff recommends that EMM calculate rates which recover about $668,113 from reactive demand across the MGS, LGS, and LPS customer rate classes.[342] In doing this, Staff recommends that EMM maintain "the general proportionality of reactive demand rates" that currently exists across the customer classes. Additionally, Staff recommends that "the rate determined for LPS customers…also be applied to LLPS customers."[343]

Issue 29(A)(iii), Issue 29(A)(iv), and Issue 29(A)(v)

Implementation of the new rate structure should not occur without addressing this issue consistent with Staff's recommendations in its direct testimony concerning inter- and

[339] Staff Rate Design Report, page 34, lines 2-6.
[340] Staff Rate Design Report, page 34, lines 7-9.
[341] Staff Rate Design Report, page 34, line 9.
[342] Staff Rate Design Report, page 34, lines 13-15.
[343] Staff Rate Design Report, page 34, lines 15-17.

intraclass pricing relationships, provided in the Staff Rate Design Report at pages 32 – 39. More discussion relating to Staff's position on these issues is found in Staff's objection.[344]

Issue 29(A)(iv) EMM Should be Ordered to Promptly Conduct a Customer Migration and Determinants Study.

As touched on above, Staff's general support for EMM's proposed restructuring is to give EMM the opportunity to begin immediate work on Staff's proposed Customer Migration and Determinants Study – so that rates can be calculated expeditiously.[345] Ms. Lange clarified in hearing that Staff does not anticipate it will take EMM a year to complete such a study.[346] In fact, as stated by Ms. Lange in response to questioning from Commissioner Coleman, "I would think this should take less than a week to do if people devote the time to it at Metro."[347] Staff's request that EMM perform a customer and migration study in the middle of a rate case is not a novel one; Staff has made this request to at least two other companies regulated by the Commission.[348]

This study is essential for setting rates in this case.[349] At this point in the case, there is a dearth of critical information needed in order to set rates. Ms. Lange pointed this out when questioned about the importance of such a study:

> We have to know how much money is supposed to be recovered, and we have to know how many units are being sold to do that. There is no information in this case about on-peak and super off-peak energy by class. There is no information in this case about 15-minute on-peak demand.[350]

[344] Docket Item No. 322.
[345] Docket Item No. 322, page 1.
[346] Unofficial Transcripts, Volume 12, PDF page 177.
[347] Unofficial Transcripts, Volume 12, PDF page 177.
[348] Unofficial Transcripts, Volume 12, PDF page 191.
[349] Staff Rate Design Report, page 26, lines 2-4; Unofficial Transcripts, Volume 12, PDF page 195.
[350] Unofficial Transcripts, Volume 12, PDF page 196.

Issue 29(A)(v) Staff Recommends the Commission Implement the Customer Education Recommendations Proposed by Staff.

The Staff-proposed Customer Education Plan, necessitated by EMM's proposed rate class restructuring, is included in Staff's objection to (Docket Item No. 313):

> Staff recommends that EMM inform its non-residential customers of the restructured rates and provide reasonable education to those customers. This should include a statement of the rate schedule the customer has been billed on, the rate schedule the customer will be billed on, simple and clear education concerning the time-based periods ordered in this case, an explanation of the recommended delay in restructuring until November 2027, and a one-time report of the following:
>
> 1. A statement of the total energy and 30-minute demand for 12 historic billing months,
>
> 2. A statement of the total energy, energy by time-based period, 15-minute NCP demand, and 15 minute on-peak demand for the same 12 historic billing months,
>
> 3. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the increased non-restructured rates that are ordered in this case, and
>
> 4. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the restructured rates that are ordered in this case and effectuate the rate increase. The Commission should also order EMM to test its billing system's ability to accurately bill the restructured rates, and to inform the Commission and the parties of any shortcomings or delays in its ability to bill through a filing in this docket.
>
> The Commission should also order EMM to test its billing system's ability to accurately bill the restructured rates, and to inform the Commission and the parties of any shortcomings or delays in its ability to bill through a filing in this docket.[351]

[351] Docket Item No. 322, Attachment A, Staff's Demonstrative Exhibit 4 from the On-the-Record presentation on October 13, 2026.

Issue 29(A)(vi) Staff Recommends that the Restructured Rates not Take Effect Until After the Summer 2027 Billing Season.

As it pertains to SGS, MGS, LGS, and related standby rates, Staff proposes that the Commission order EMM to take the following actions:

1. File one set of tariff sheets as currently numbered and paginated, with each rate increased by [system average increase] and with a heading indicating that the rates are applicable to service prior to November 1, 2027, including the frozen "All Electric" SGA, MGA, and LGA rate schedules, and the "Large Power Service Off-Peak Rider."
2. File additional tariff sheets on new tariff sheet numbers, setting out restructured rates as recommended above, which are denominated as applicable to service on and after November 1, 2027.
3. Staff does not recommend creation of highly-differentiated time-based non-residential rate schedules at this time.
4. Staff recommends that LLPS, Clean Charge Network, Electric Vehicle Charging rates, Lighting, and Time Related Pricing rates each be increased by the applicable [system average increase] increase, without limitations on the timing of applicability, and without revision on November 1, 2027.
5. For standby rate schedules for service on and after November 1, 2027, Staff recommends the following:
    a. Alignment of paragraph 11, "Standby Service Demand," with the 15-minute demands, demand bright lines, and peak demand periods established for the SGS, MGS, LGS, and LPS restructured schedules.
    b. Alignment of the rates for service structures and rates with those established for the SGS, MGS, LGS, and LPS restructured schedules.[352]

[352] Rate Design Report, page 26, line 9 – page 27, line 5.

Issues 29(B) Staff Recommends the Commission Reject the non-residential non-lighting opt-in time-based rates proposed by EMM.

As stated above, EMM and MECG entered into (Docket Item No. 313), resolving this issue between the two parties. Staff objects to this agreement as a whole and specifically to the provision in this agreement which deals with this issue. Staff provided its reasoning for its objection to how this issue was dealt with in this agreement in its objection filed on October 7, 2026.[353]

Andrea B. Hansen

Issue 30. Other Rate Schedules

A. How should all other applicable rates in this case be increased, including lighting, Large Load Power Service, Electric Vehicle Charging, and Time Related Pricing, if applicable?

i. Should the TRP (Time Related Pricing) rate schedule be eliminated?

Issue 30(A) Staff Recommends the Commission Adopt its Position Regarding Rate Increases Including Lighting, LLPS, Electric Vehicle Charging, and Time Related Pricing.

As stated in Staff's objection to (Docket Item No. 313), "no reliable CCOS study is available in this case to support a result other than an equal percentage increase to all classes."[354]

Issue 30(A)(i) Should the Time Related Pricing ("TRP") Rate Schedule be Eliminated?

As Staff stated in its objection to (Docket Item No. 313):

> Staff does not object to the freezing of the TRP rate for current customers in the non-residential class as contemplated by page 3 of [Docket Item No. 313], Staff does object to increasing the components of this rate by 1.1 times the system average rate increase. Staff objects because this provision is being utilized to provide additional avoidance of applicable rate increases to LPS customers.[355]

Andrea B. Hansen

[353] Docket Item No. 322.
[354] Docket Item No. 322, page 2.
[355] Docket Item No. 322, paragraph 14.

Issue 30(A)(ii) Should Schedule LLPS rates be increased in this proceeding and by how much?

The Commission should increase Schedule Large Load Power Service ("LLPS") rates by the same percentage applied to other customer classes.

Staff recommends an equal percentage increase because the class cost-of-service ("CCOS") studies in this proceeding do not provide a reliable basis for shifting revenue responsibility among customer classes. As explained in Staff's Rate Design Report, those studies cannot adequately account for the migration of customers resulting from EMM's proposed rate restructuring or the significant new load being added to the system without sufficient information concerning that load's usage characteristics. Staff therefore recommends maintaining the existing relative revenue responsibilities while the Company transitions to its restructured rates.[356]

Staff witness Sarah Lange identified additional deficiencies in EMM's CCOS study, including its classification of distribution costs, allocation of production costs, and treatment of transmission expenses.[357] Those deficiencies are particularly relevant to the proposed treatment of LLPS customers. As Lange explained, EMM's CCOS studies do not adequately reflect the substantial changes in demand and energy requirements associated with new large loads. Consequently, the studies cannot reliably establish the costs attributable to the customer classes that will exist following restructuring.[358]

The October 5, 2026, Non-Unanimous Partial Settlement between EMM and MECG nevertheless proposes increasing LPS rates, including LLPS, by only 94% of the system-

[356] *Staff Rate Design Report* at pg. 4, lls. 7–19; pg. 5, lls. 1–7, EFIS Item 124.
[357] Rebuttal Testimony of Sarah L.K. Lange at pg. 53, line 9 through pg. 54, line 12, EFIS Item 163.
[358] *Id.* at 54, lls. 13–21.

average percentage increase, while SGS and MGS customers would receive 112.44%.[359] The settlement does not cure the deficiencies Staff identified. Indeed, Lange explained that MECG witness Jessica York's CCOS analysis retains the problematic production and distribution allocation methodologies underlying EMM's study.[360] The resulting analysis therefore does not provide a reliable basis for assigning LLPS customers a comparatively smaller rate increase.

Nor does the separate EMM–Google LLPS stipulation resolve this concern. Although that agreement proposes recognizing $60 million in LLPS revenues, the treatment of those revenues in determining EMM's revenue requirement is distinct from the question of how the authorized rate increase should be apportioned among customer classes.[361] Staff's Rate Design Report expressly recognizes this distinction by accounting for new net revenues from large loads separately from its recommended equal percentage increase to existing customer classes.[362]

The Commission should therefore reject the proposed preferential increase for LLPS customers and apply the same percentage increase to Schedule LLPS as to other applicable customer classes. This approach recognizes the limitations of the available CCOS evidence, avoids unsupported shifts in revenue responsibility, and maintains reasonable rate relationships while EMM implements its restructured non-residential rates.

Mark Johnson

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[359] *Non-Unanimous Partial Settlement—Rate Design*, paragraph 2, EFIS Item 313.
[360] *Lange Rebuttal*, at pg. 56, lls. 1–18.
[361] *LLPS Partial Stipulation and Agreement,* paragraph 13, EFIS Item 314; *Staff Objection to LLPS Partial Stipulation and Agreement*, EFIS Item 318.
[362] *Staff Rate Design Report*, at pg. 4, lls. 13-19.

Issue 30(B) Staff Recommends that the Commission Adopt (Docket Item No. 311) as a Whole. If the Commission Chooses not to Adopt (Docket Item No. 311), Staff Still Recommends that Obsolete Rate Schedules and Riders be Removed from the EMM Tariff Book.

Staff recommends the Commission adopt (Docket Item No. 311) as a whole. If the Commission chooses not to adopt (Docket Item No. 311), Staff recommends the Commission eliminate obsolete rate schedules and riders as discussed on page two, section 28 of (Docket Item No. 311).

Andrea B. Hansen

Issue 31: Large Load Power Service Tariff and Reporting

Introduction

The Commission should order EMM to include construction power within the optional five-year ramp period, expressly prohibit demand above the applicable contract demand, protect non-LLPS customers from costs caused by an exceedance, and use an exceeded demand level as the new basis for minimum demand charges. It should also make explicit that energy charges and other charges cannot offset the minimum demand-based obligation. Finally, it should order the annual, agreement-specific, rate-case, and monthly reporting described below.

These measures give practical effect to the tariff's protections. A contractual demand commitment provides little protection if the customer can exceed it without an accompanying financial responsibility. A minimum demand provides little protection if energy sales offset. And neither protection can be evaluated reliably without timely agreements, forecasts, engineering information, and interval load data. Staff's

recommendations connect the customer's service commitment, the utility's planning obligations, and the information necessary to verify compliance.

The LLPS Agreement (Stipulation V) reached between EMM and Google does not dispose of these questions. Its minimum-demand provision supplies a useful point of agreement, but Staff objected to treating the package as a resolution of the disputed LLPS issues, including its omission of reporting and contract-demand protections.

Authority

Section 393.140(5), RSMo, authorizes the Commission, after hearing, to prescribe just and reasonable rates, charges, acts, and regulations when existing ones are unjust or unreasonable. Section 393.140(11) addresses filed schedules governing rates, service, and agreements. Those provisions support prospective clarification of the LLPS service and billing requirements. Sections 393.140(8) and (9) separately authorize examination of utility contracts and records, specific answers to Commission inquiries, and periodic reports.

Argument

A. What tariff changes or clarification, if any, should be made to the Large Load Power Service tariff?

I. The five-year ramp period should include construction power.

EMM's Tariff Sheet No. 76 provides for an optional transitional load ramp period of up to five years plus twelve years of service, with the term beginning when permanent service begins or as specified in the service agreement. It also permits load below 75 MW during the

ramp. Staff recommends clarifying that construction power falls within that ramp period, preventing an effective transition longer than the five years contemplated by the tariff.[363]

EMM witness Brad Lutz responds that construction power is separate from LLPS service. In his account, construction commonly precedes the customer's business use and is undertaken by a third party that controls the site until completion. He regards the ramp as the period when the large-load customer takes control and outfits and commissions the facility.[364] The distinction explains EMM's practice, but it does not answer Staff's concern: the same large-load project can receive electric service during construction without fulfilling its minimum demand obligations.

The Commission should define the relevant service milestone in the tariff itself. Reliance on a service agreement's characterization of service as temporary, construction, or permanent leaves the timing of a public tariff protection dependent on labels negotiated for an individual project. The tariff already anticipates service below the ultimate LLPS threshold during transition; the fact that the project is not yet operating at full business load therefore does not establish that electric service supporting its construction must be excluded from the transition.[365]

Staff requests a Commission order stating that the ramp period includes provision of construction power for the LLPS project. The compliance tariff should state the commencement event clearly and carry that date consistently into the service agreement and reporting. Staff further notes that this request does not depend on a finding about the

[363] Exhibit 124, Direct Testimony of Sarah L.K. Lange (Rate Design), p. 5, ln. 10-14 through p. 6, ll. 1-16.
[364] Exhibit 55, Bradley D. Lutz Rebuttal Testimony, p. 26, ll. 1-10 and p. 37, ll. 7-22.
[365] Ex. 124, p. 5, ln. 10-14 through p. 6, ll. 1-16.

identity or conduct of any particular customer or contractor. This recommendation is a ***clarification*** of the Commission's previous decision in Evergy's LLPS tariff case, Case No. EO-2025-0154.

II. Contract demand must be an enforceable limit with corresponding cost responsibility.

While the Commission was aware of the SPP revision request to implement Conditional High Impact Large Load Services ("CHILLS"), the Report and Order nor the stipulation addresses how, or if, EMM will charge LLPS customers utilizing CHILLS. FERC approval occurred with SPP's tariffs to be effective on July 1, 2026. [366]

The tariff should expressly provide that the applicable contract demand may not be exceeded and that EMM must take reasonable steps to prevent exceedance, including during the ramp period. If exceedance nevertheless occurs, non-LLPS ratepayers must be held harmless from every cost attributable to it, and the exceeded demand level must become the new basis for minimum-demand charges. These are the three protections Ms. Lange recommends in her testimony.[367]

Each protection serves a different purpose. The prohibition establishes the operational obligation. The hold-harmless requirement assigns the financial consequences when the obligation is breached. The increased minimum demand prevents a customer from continuing to receive service at a demonstrated higher demand while retaining a minimum payment obligation based on a lower commitment. An increased minimum demand alone

[366] Exhibit 123, Notice of Corrected Testimony of Claire M. Eubanks, PE, p. 13, ll. 2-4.
[367] Ex. 124, p. 8, ll. 1-8.

would leave open recovery from other classes of costs incurred because the customer exceeded its commitment; a hold-harmless requirement alone would leave the future minimum-demand basis unresolved.[368]

Transmission service concerns delivery; generation capacity concerns available resources; resource adequacy requires both sufficient resources and deliverability. The availability of conditional, non-firm transmission under SPP's CHILLS provisions therefore does not itself establish that all resource-adequacy consequences of higher retail demand have been addressed. The Commission need not regulate SPP's wholesale tariff to define the retail customer's demand commitment and protect EMM's other retail customers from exceedance costs. The hold harmless provision shields other retail customers from those costs.

The need to plan for load before a mature operating history exists is a reason to define the obligation now. Waiting until a large customer has exceeded its commitment leaves the utility and the Commission to address costs after the event. Staff's proposal establishes the governing responsibility in advance. The Commission should direct EMM to submit compliance language implementing all three elements. It should require the language to identify the applicable contract-demand measure during the ramp, the resulting minimum-demand basis after an exceedance, and EMM's obligation to demonstrate that exceedance costs are not assigned to non-LLPS customers. These implementation details should make the ordered protection enforceable. This recommendation is a ***development*** since the Commission's previous decision in Evergy's LLPS tariff case, Case No. EO-2025-0154.

[368] *Id*.

III. The minimum demand obligation must be collected in addition to energy charges.

Staff identifies a concrete billing problem: EMM's calculation offsets energy, DSIM, and FAC charges against the minimum bill instead of preserving the minimum demand-related charges. Ms. Lange reproduces the tariff's list of minimum monthly bill components and explains how the offset diminishes the amount collected for the demand commitment.[369] Staff requests clarification that the demand-based minimum uses 80% of contract demand, without reduction for energy charges or any other amount used as an offset against that obligation.

Mr. Lutz describes EMM's calculation in three steps. EMM first determines a threshold using minimum demand, then computes the bill from actual usage, and finally adds a Contract Minimum Balance if the actual-usage bill falls below the threshold.[370] That description makes the dispute substantive rather than merely a matter of bill presentation. If additional energy charges reduce the balance needed to reach a fixed total threshold, energy consumption can displace part of the minimum demand-related payment.

Google witness Dr. Carolyn Berry disagrees with Ms. Lange's characterization of EMM's method, but her own tariff analysis supports the critical billing instruction. She explains that Billing Demand is the higher of measured monthly demand or Minimum Demand, and that Minimum Demand is 80% of annual Contract Capacity. She concludes that EMM should have used the higher minimum demand in computing the demand charge

[369] Exhibit 138, Rebuttal Testimony of Sarah L.K. Lange, p. 9, ll. 13 through p. 12, ll. 2.
[370] Exhibit 57, Bradley D. Lutz Surrebuttal Testimony, p. 11, ln. 12 through p. 14, ll. 8.

on the actual bill. She further explains that minimum demand charges protect other customers from cost shifts.[371]

The LLPS Agreement reflects the same operative distinction. Paragraph 4 of the LLPS Agreement specifies billing demand equal to the higher of measured demand or 80% of annual Contract Capacity, in addition to the other LLPS charges, including energy-based charges; paragraph 5 provides for tariff redlines. EMM witness Darrin Ives likewise testified that the stipulated revenue calculation used Dr. Berry's clarification applying energy charges on top of minimum demand.[372]

The Commission should order that result directly. Each monthly bill must preserve the applicable demand-based minimum calculated from 80% of contract demand and separately assess energy-based charges under the tariff. Where measured demand is higher, the higher billing-demand provision governs. Energy, DSIM, FAC, or another charge cannot operate as a credit that reduces the minimum demand-based obligation. This disposition implements Staff's requested clarification while addressing the billing defect identified by Dr. Berry as well. This recommendation is ***implementation of*** the Commission's previous decision in Evergy's LLPS tariff case, Case No. EO-2025-0154.

B. What reporting requirements are appropriate concerning new large loads and load growth?

Staff witness Claire M. Eubanks, PE explains that Staff must understand whether, when, and how fully new load will materialize, and how it uses electricity over time. IRP

[371] Exhibit 453, Surrebuttal Testimony of Dr. Carolyn Berry, pp. 7-9.
[372] Unofficial Tr. Vol. 12 (Public), p. 57, ll. 13-22.

information does not arrive on a schedule aligned with Staff's rate-case work. She therefore recommends annual reporting, prompt delivery of executed agreements and related information, and prescribed rate-case load data.[373] Ms. Eubanks' recommendation is simply for the Commission to order the same reporting that Ameren Missouri agreed to, and the Commission ordered in ET-2025-0184 when it approve the Amended Non-Unanimous Global Stipulation and Agreement. The recommended reporting conditions are outlined in paragraphs 37, 51, and 52 of that agreement. Ms. Lange separately recommends continued monthly reporting of LLPS hourly loads apart from LPS customers, as required by existing Commission rule Chapter 3.190.[374]

This is not a request based solely on the possibility of future discovery difficulties. Ms. Eubanks testifies that, despite discovery beginning March 6, 2026, EMM had not provided hourly load for Customer A, estimated or actual, by the time her testimony was filed on June 30, 2026. She identifies single-customer annualization, class-load annualization, production cost modeling, and jurisdictional allocation as uses for granular information.[375] That evidence establishes both the information gap and its regulatory consequence.

EMM's witnesses dispute Staff's substantive conclusions about LLPS costs, revenues, and forecasts. Mr. Gunn invokes the approved framework's safeguards and future review;[376] Mr. Ives contends that extensive changes are premature;[377] Ms. Nunn cautions that projected customer ramp rates, market prices, transmission costs, and usage may differ

[373] Exhibit 123, Notice of Corrected Testimony of Claire M. Eubanks, PE, p. 14, ll. 19 through p. 20, ln 2.
[374] Exhibit 167, Surrebuttal/True-Up Direct Testimony of Sarah L.K. Lange, p. 9, ll. 1-6.
[375] Ex. 123, p. 19, ll. 10-19.
[376] Exhibit 22, Kevin D. Gunn Rebuttal Testimony of, pp. 2, ln. 17-19.
[377] Exhibit 30, Darrin R. Ives Rebuttal Testimony of, p. 3, ll. 6-9.

from actual outcomes.[378] Those disputes strengthen the case for a common, timely information record. Reporting enables the Commission to compare assumptions against performance without resolving those broader disputes.

I. Annual compliance reporting will help keep the Commission better informed and drive a collaborative process.

The Commission should direct EMM, Staff, OPC, and other interested parties in this case to meet and determine the contents and confidentiality of an annual compliance report. At a minimum, the report should identify the number of new or expanded customers taking LLPS and the total estimated LLPS load. Energy usage information should be confidential and anonymized.[379]

Mr. Lutz points to paragraph 35 of the stipulation in EMM's LLPS tariff case, Case No. EO-2025-0154, which already provides for stakeholder development of an annual report containing new or expanded customer counts and estimated enrolled load, with confidential and anonymized energy usage information and at least annual meetings with Staff and OPC.[380] That existing commitment supports the practicality of Staff's requested process. The Commission can incorporate and implement the existing commitment in this order; Staff's request need not result in duplicative annual reports.

An annual overview serves a different purpose from agreement-specific information. The overview lets the Commission track the scale and development of the LLPS class. It does not disclose, by itself, the contractual commitments, capacity implications, or facilities

[378] Exhibit 72, Linda Nunn Rebuttal Testimony of, pp. 11-12.
[379] Ex. 123, p. 16, ll. 7-15.
[380] Ex. 55, p. 27, ll. 11-28.

associated with a particular addition. The Commission should require both forms of information.

II. Executed agreements and supporting information should be provided within 30 days of execution.

Within 30 days after execution of any agreement relating to LLPS with an LLPS customer, EMM should provide Staff the executed agreement(s) and the following information, protected at a confidentiality level commensurate with this docket: (1) updated capacity and demand forecasts with and without the new customer; (2) the boundary of EMM's serving facilities in a format supported by the State's GIS software; (3) evidence of completed internal engineering studies, descriptions of needed interconnection upgrades and facilities, and the complete interconnection study; (4) the construction agreement documenting estimated interconnection costs and the proposed recording of those costs on EMM's books; and, to the extent known to EMM, (5) the customer's full corporate name and registration information and that of all parent companies.[381]

Ms. Eubanks ties these materials to defined functions. Agreements permit tariff-compliance review. Forecasts reveal the customer's capacity implications. Facility boundaries support emergency-response work and service-quality inquiries. Engineering studies, construction estimates, and accounting information support timely rate-case audits.[382] The comparison of forecasts with and without a customer is

[381] Ex. 123, p. 17, ll. 1 through p. 18, ll. 2.
[382] *Id*, p. 18, ll. 3-13.

especially useful because an aggregate forecast can conceal the assumptions attributable to one large addition.

Mr. Lutz objects that much of the information is premature outside a rate case, unnecessary to examine the ESA itself, or an attempt to manage LLPS implementation. He nevertheless accepts that executed ESAs can be provided, subject to confidentiality protections.[383] His objection defines the regulatory purpose too narrowly. Staff is not reviewing only whether the agreement contains the right words. It must also examine tariff compliance, demand and capacity consequences, facility costs, and the accounting that can affect future rates.

The proposed trigger is execution of an agreement. Staff does not request approval authority over the utility's negotiations or construction management. EMM retains those responsibilities. The order supplies a prompt, predictable disclosure obligation after the commitment is made. Confidentiality concerns are addressed by applying protections commensurate with those already in this docket, rather than withholding information needed for oversight.

III. Rate-case workpapers must contain actual interval loads and updates through true-up.

In each rate case after an LLPS customer begins permanent service, which Ms. Eubanks identifies with commencement of the ramp, EMM should provide actual hourly customer load in its direct-case workpapers. The reporting period should begin with the later of the month following commencement of permanent service or the end of the test year of a

[383] Ex. 55, pp. 28-30.

previous rate case in which that customer's load was reported, and continue through the test year used in the current case.[384]

EMM should update information included in its direct-case through the date agreed with Staff for calculating billing units for Staff's initial responsive filing. In every event, EMM should update information included in its direct-case through the true-up cutoff when providing true-up data. It should provide hourly load and 15-minute demand intervals upon request, subject to confidentiality protections commensurate with this docket.[385] This follows the actual rate-case process and prevents the filed load information from becoming obsolete during the audit.

EMM witness JP Meitner objects that Evergy's models and SPP submissions use hourly data, and that greater granularity is unnecessary and quickly becomes infeasible.[386] Hourly information may suffice for particular production-cost or SPP settlement functions, but those functions do not exhaust Staff's work. Specifically, 15-minute demand data is needed for customer revenue annualization.[387] Ms. Eubanks identifies the tariff's Monthly Maximum Demand as the highest demand in a 15-minute interval during the month across all meters.[388] Hourly averages cannot independently verify that interval maximum.

The Commission should therefore retain the distinction in Staff's proposal: routine hourly load data, supplemented by 15-minute demand information upon request. That approach supports energy analysis and demand-charge verification without asserting

[384] Ex. 123, p. 18, ll. 14 through p. 19, ll. 9.
[385] *Id*, pg. 19, ll. 11-19.
[386] Exhibit 63, JP Meitner Rebuttal Testimony, p. 7, ll. 1-20.
[387] Ex. 167, p. 19, ll. 1-2.
[388] Ex. 123, p. 19, footnote 19.

that every modeling exercise requires 15-minute resolution. It also directly supports the demand-limit and minimum-billing protections addressed earlier in this section of the brief under Issue A.

IV. Monthly reporting must preserve LLPS as a separate class.

The Commission should order EMM to continue including LLPS hourly loads in its monthly reporting under Commission Rule 20 CSR 4240-3.190, separately from LPS hourly loads. Ms. Lange recommends separate rate codes for the applicable voltage levels and seeks the express reporting directive out of caution.[389]

Conclusion

Staff requests that the Commission resolve Issue A by directing compliance tariff language that includes construction power within the optional five-year ramp; prohibits exceedance of the applicable contract demand and requires EMM to take reasonable preventive steps, including during the ramp period; holds non-LLPS customers harmless from all exceedance costs; resets the minimum-demand basis to the exceeded demand level; and preserves the 80% contract-demand minimum without offsets from energy or other charges, applying higher measured billing demand where required.

Staff requests that the Commission resolve Issue B by ordering the collaborative annual-report process; rate case related minimum contents, including executed LLPS agreements and supporting information within thirty days of execution; actual hourly rate-case load data with the specified updates through true-up and 15-minute demand data upon request; and continued monthly LLPS hourly-load reporting separate from LPS under 20 CSR 4240-3.190. Confidentiality should be maintained as specified above. The order should

[389] Ex. 167, p. 9, ll. 1-6.

implement these requirements expressly, regardless of the disposition of the LLPS Agreement's other LLPS provisions.

Travis J. Pringle

Issue 32. Revenue Apportionment and Implementation
A. How should revenue responsibility, including any net revenues from LLPS customers and any reduction to revenues from any income-eligible customer discounts, be apportioned among the customer classes, if at all?
i. What is the appropriate classification of customer-classified distribution system cost of service for any class cost of service study relied upon in this case?
ii. What is the appropriate allocation of production-related cost of service for any class cost of service study relied upon in this case?
B. How should customer affordability, including for low- and moderate-income households, be reflected in the rates ordered in this case?

Issue 32(A) - 32(B) Staff Recommends the Commission Adopt its Position Regarding Revenue Apportionment and Implementation.

Because no party in this case was able to perform a meaningful CCOS study in this case, Staff recommends an equal percentage increase "to the classes as currently constituted, subject to adjustment for finalization of the impacts of economic development incentives and the offset of new net revenue from large loads."[390] However, "[t]his adjustment is not applicable to revenues from charges such as solar block charges, and net metering credits."[391] For several reasons discussed in Ms. Lange's Rebuttal Testimony, The EMM and derivative CCOS studies neither reasonably classify and allocate distribution-related cost of service, nor do they reasonably allocate production and energy-related cost of service.[392] Customer affordability (including for low and moderate income households) should be reflected in rates in accordance with Staff's position regarding Issue 16(E)(ii).[393]

[390] Docket Item No. 295, page 33; Staff Rate Design Report, page 4, lines 7-15.
[391] Docket Item No. 295, page 33; Staff Rate Design Report, page 4, lines 15-16.
[392] Docket Item No. 295, page 34; Sarah Lange Rebuttal page 35 line 12 – page 51 line 15; Sarah Lange Rebuttal, page 30 line 1 – page 35 line 12.
[393] Docket Item No. 295, page 35.

C. Should EMM's surrebuttal proposal to implement the rate increase by bill cycle in this case be permitted?

Issue 32(C) Staff Recommends the Commission Reject EMM's Proposal to Implement the Rate Increase by Bill Cycle.

In its objection to (Docket Item 313), Staff stated its opposition to immediate implementation of new rates by bill cycle for the following reasons:

1. Immediate implementation will result in a rate increase and a significant change in rate structure in the peak winter billing months, without the benefit of any meaningful customer education. This runs unnecessary and unreasonable risk of rate shock and customer disgruntlement, as opposed to providing an opportunity for customers to understand the purposes behind the pricing of the new rate structure, and to modify usage, if applicable, accordingly.
2. This proposal was not brought forth until surrebuttal testimony, and no party has had an opportunity to address the impacts of its interaction with riders such as Fuel Adjustment Clause ("FAC") and Missouri Energy Efficiency Investment Act ("MEEIA") riders.
3. Staff's recommended customer education plan was provided in the Staff Rate Design Report beginning at page 27 and is attached for reference as Attachment A.[394]

D. How should revenue responsibility for construction work in progress be assigned or allocated among the customer classes?

Issue 32(D) Staff Recommends the Commission Implement Staff's Proposed Revenue Responsibility Class Allocation for Construction Work in Progress.

As discussed in Issue 20(B), if CWIP is included in rate base, the Commission should not include unsupported amounts from affiliate, Transource Missouri, and should be subject to the pre-tax overall rate of return ordered by the Commission and set forth in the Staff's

[394] Docket Item No. 322, page 3.

Accounting Schedules filed in this case. This results in an annual recovery associated with Mullin Creek 2 CWIP of ** [redacted] **.[395]

To calculate for proportionate recovery of Mullin Creek 2 CWIP from LLPS customers, multiply the annual CWIP recovery, ** [redacted] **, by the current LLPS share of Mullin Creek 2 capacity,[396] 46.14%, and divide by the annual LLPS demand.[397] Resulting in an addition to the $/kW rate of $0.93.

To calculate full allocation to the LLPS class, the Commission would simply divide ** [redacted] ** by the annual LLPS demand.[398] Resulting in an addition to the $/kW rate of $2.01.

Andrea B. Hansen

Issue 33. Critical Peak Rate
A. Should the Critical Peak Rate recommended by Staff be implemented?
i. If not implemented, are other accommodations needed to address high market cost events and establish offsetting revenues to be applied through the FAC?

Issue 33(A)(i) If [CPR is] not implemented, are other accommodations needed to address high market cost events and establish offsetting revenues to be applied through the FAC?

Possibly. Staff takes no position at this time but reserves the right to do so in its Reply Brief.

[395] $64 million (Young true-up rebuttal page 2, line 6) less ** [redacted] ** (Young true-up rebuttal page 3, line 10) equates to ** [redacted] ** Apply Staff's mid-point pre-tax rate of return of 7.708% (Staff Accounting Schedules- Revised True-Up Rebuttal).
[396] LLPS monthly demand is *** [redacted] *** (conforming direct testimony of Sarah L.K. Lange, page 35, line 1) and Mullin Creek 2 accredited capacity is ** [redacted] ** (footnote 19, page 19 of Sarah L. K. Lange Rebuttal testimony). *** [redacted] *** divided by ** [redacted] ** is 46.14%.
[397] *** [redacted] *** times 12 months per year equates to *** [redacted] ***.
[398] *** [redacted] *** times 12 months per year equates to *** [redacted] ***.

B. Should EMM have a separate line on its fuel adjustment rate tariff to account for critical peak pricing?

Issue 33(B) Staff Recommends the Commission Order EMM to Include a Separate Line on its Fuel Adjustment Rate Tariff to Account for Critical Peak Pricing.

If the Commission adopts the CPR (either Option 1 or Option 2), Staff recommends the Commission include "a new line in the proposed 5th Revised Sheet No. 50.10, with a description of Critical Peak Rate Revenue."[399] This proposed line would be located beneath "the current line 10 Prudence Adjustment Amount and above the current line 11, Fuel and Purchased Power Adjustment."[400]

Andrea B. Hansen

Issue 36. Critical Infrastructure Protection and Cyber Security

A. What level of critical infrastructure protection ("CIP") and cyber security expense should be included in the revenue requirement?

The Commission should include Staff's recommended test-year level of $4,491,745 for CIP and Cyber-Security costs.[401] This is comparable to the level experienced by EMM historically.[402] Staff included the test year amount of these costs as cybersecurity costs have not fluctuated significantly in recent years.[403]

EMM witness Ronald A. Klote proposes including $4,492,878 in CIP and cybersecurity operation and maintenance expenses on a total-company basis.[404]

[399] Staff Rate Design Report, pg. 48, lines 12-15. (Internal quotations omitted).
[400] Staff Rate Design Report, pg. 48, lines 15-17. (Internal quotations omitted).
[401] Ex. 140 Rebuttal Testimony of Karen Lyons, pg. 10, ln. 16 – pg. 11, ln. 2, Case No. ER-2026-0143, EFIS Item No. 165 as modified by EFIS Item No. 330 *Notice of Karen Lyons Errata Sheet* at p. 1.vii.
[402] Id.
[403]Ex. 168 Surrebuttal/True-Up Direct Testimony of Keith Majors, pg 15, lns. 1-7, Case No. ER-2026-0143, EFIS Item No. 253.
[404] Direct Testimony of Ronald A. Klote, pg. 36, lines 21-22.

There is little substantive disagreement concerning the appropriate methodology for establishing these costs in base rates. Both Staff and EMM recommend using the actual expenses incurred during the twelve-month test year ending June 30, 2025.[405] The parties differ slightly concerning the resulting amount.

Staff's recommendation is supported by the Company's historical expenditures. Staff witness, Karen Lyons examined EMM's actual cybersecurity expenses and determined that they had remained relatively consistent over the period examined. The Company's annual expenses were $3,909,748 in 2023, $4,613,752 in 2024, and $4,216,892 in 2025.[406]

Those expenditures demonstrate that cybersecurity is an established and recurring component of EMM's cost of providing electric service. They also demonstrate that the Company has historically managed those costs without the substantial year-to-year fluctuations it now anticipates.

The Commission should therefore adopt Staff's recommended test-year level of $4,491,745 on a total-company basis, subject to the applicable jurisdictional allocation.

B. Should EMM implement a tracker for CIP and cyber security costs?

The Commission should reject EMM’s proposed tracker for CIP and cyber security costs because the fundamental reasons for the use of trackers are not present for this issue in this case.

Staff does not dispute that protecting EMM's critical infrastructure is necessary. Nor does Staff dispute that cybersecurity threats continue to evolve or that the Company

[405] Ex. 140, pg. 11, lines 5-6.
[406] Ex. 140, pg. 10, lines 16-29, as corrected by *Notice of Karen Lyons Errata Sheet* at pg. 1i.

must remain capable of responding to those threats. The question is whether the possibility of increased future costs justifies departing from ordinary ratemaking principles and authorizing a mechanism that would allow EMM to defer differences between its actual cybersecurity expenses and the amounts included in rates.

While Staff does not oppose the use of trackers across the board, the record does not support that departure in this instance.

Under traditional ratemaking, the Commission establishes rates based upon a representative level of operating expenses. The utility bears the risk that actual expenses may exceed those reflected in rates, while retaining the benefit when expenses are lower. A tracker changes that relationship by allowing differences between actual expenses and the amounts included in rates to be recorded for potential recovery or refund in a subsequent rate proceeding.[407]

As Staff witness Karen Lyons explained, Staff generally supports trackers only when expenses are material and exhibit significant, unpredictable fluctuations; involve substantial new costs with little historical experience; or result from newly promulgated Commission rules.[408] None of those circumstances has been demonstrated here.

EMM's historical cybersecurity expenses have been relatively stable. Staff's review identified annual expenditures of $3.91 million in 2023, $4.61 million in 2024, and $4.22 million in 2025.[409] These figures demonstrate that cybersecurity expenses are established, recurring costs that EMM has historically managed through its ordinary

[407] Ex. 140, Lyons Rebuttal, pg. 2, line 13 through pg. 3, line 2.
[408] *Id.* at pg. 3, lines 14-20.
[409] *Id.* at pg. 10, line 16 through pg. 11, line 16, as corrected by *Notice of Karen Lyons Errata Sheet* at pg. 1i.

operations. Indeed, as stated above, both Staff and EMM propose including essentially the same test-year level of cybersecurity expenses in base rates.

EMM nevertheless argues that cybersecurity costs may increase because of evolving threats, changes in technology, and additional regulatory requirements. Company witness Charles King identified the growing sophistication of cyberattacks, the increasing use of subscription-based cybersecurity software, and potential federal compliance obligations as reasons for authorizing the tracker.[410]

Staff does not dispute that these developments may affect EMM's future expenses. However, the possibility that costs may increase is not a sufficient reason to authorize a tracker. Nearly every category of utility expense is subject to changing market conditions, regulatory requirements, or technological developments. If those possibilities alone justified tracking, the exception would swallow the rule.

Moreover, the Company's historical experience undermines its argument. As OPC witness Angela Schaben explained, cybersecurity threats and regulatory requirements have continued to evolve for years, yet EMM's actual expenditures have remained relatively consistent.[411] EMM has not established that future changes will produce expenses so substantial or unpredictable that they cannot reasonably be addressed through ordinary ratemaking.

Nor is a tracker necessary for EMM to respond to cybersecurity threats. A tracker does not provide immediate funding or eliminate the Company's responsibility to protect its

[410] *Rebuttal Testimony of Charles King*, pgs. 3-6.
[411] *Surrebuttal Testimony of Angela Schaben,* pgs. 23-31.

system. It merely records differences in expenses for potential treatment in a future rate proceeding.[412] EMM remains responsible for maintaining the security and reliability of its infrastructure regardless of whether the Commission authorizes the requested accounting mechanism.

EMM also points to the Kansas Corporation Commission's approval of a similar tracker for its Kansas utilities. But the treatment approved in another jurisdiction does not establish that EMM's Missouri expenses warrant a departure from traditional ratemaking.[413] The Commission must make that determination based upon the evidence presented here.

The Commission has previously recognized that trackers should be used sparingly because they diminish the incentives inherent in traditional ratemaking.[414] Staff's recommendation is consistent with that principle. EMM has demonstrated that cybersecurity is an important and ongoing responsibility, but it has not demonstrated that the associated expenses possess the characteristics necessary to justify a tracker.

The Commission should therefore reject EMM's proposed CIP and cybersecurity tracker and continue recovering these expenses through base rates.

Mark Johnson

Issue 37: Revenue Sharing Mechanism

Should the Commission implement a mechanism to review or share earnings attributable to Schedule LLPS customers, and if so, how should it be designed?

[412] Ex. 140, *Lyons Rebuttal* at pg. 2, line 13 through pg. 3, line 2.
[413] *King Rebuttal* at pg. 7, lines 3-9.
[414] *In re Union Electric Co. d/b/a AmerenUE*, No. ER-2010-0036, Report and Order at 65–68 (Mo. Pub. Serv. Comm'n 2010) (discussing the limited circumstances warranting expense trackers).

Staff recommends the Commission design the earnings sharing mechanism to be identical to the earnings sharing mechanism established in Case No. ET-2026-0184 for Ameren Missouri.[415]

Introduction

The Commission should implement an earnings review and sharing mechanism for EMM using the mechanism established for Ameren Missouri in Case No. ET-2025-0184 and reproduced in Staff witness Kimberly Bolin's Surrebuttal Testimony, Schedule KKB-s2.[416] The mechanism should preserve Ameren Missouri's substantive design: an LLPS base-rate-revenue growth trigger; a companywide earned-return test; sharing of 65 percent of positive, tax-grossed-up earnings above the applicable ROE benchmark; limited surveillance adjustments; a regulatory liability for customers; and subsequent Commission determination of amortization. It should not include the additional 20-basis-point retention allowance proposed in EMM's LLPS Agreement with Google.

The revenues and costs of customers ramping onto Schedule LLPS can change materially after the true-up cutoff and before the next rate case. Ms. Bolin explains that significant post-true-up revenue growth could permit EMM to over-earn until its next rate case. EMM acknowledges that same uncertainty. An annual review using actual companywide results protects customers against that outcome while accounting for the expenses and investment necessary to serve growth.[417]

[415] Exhibit 150, Surrebuttal Testimony of Kim Bolin, p. 3, ll. 1-3.
[416] *Id*.
[417] Ex. 150, p. 2, ll. 14-22; *see also* Exhibit 42, Ronald A. Klote Rebuttal Testimony, p. 3, ll. 8-22.

Staff's recommendation is conditional in the precise manner stated in its position: if the Commission adopts a sharing mechanism, its design should be identical in substance to Ameren Missouri's.[418] Staff expressly maintained its Ameren Missouri-based recommendation when it objected to the LLPS Agreement.

Argument

Ms. Bolin identifies the risk that large-user revenues will increase substantially after the true-up period.[419] EMM witness Ronald A. Klote acknowledges that the case coincides with a large customer's ramp phase and that revenues and expenses may change between true-up and implementation of rates.[420] His surrebuttal further recognizes that the proposals arise from concern that Schedule LLPS growth could produce earnings beyond those contemplated in this proceeding.[421]

EMM's own witnesses accept earnings review as a regulatory tool. EMM witness Darrin Ives recommends evaluating total revenues, expenses, capital investments, and other factors affecting overall earnings if the Commission adopts a mechanism.[422] EMM witness Kevin Gunn agrees that an overall earned-ROE measure captures interactions with the FAC and construction accounting.[423] Mr. Klote states that EMM is not opposed in principle to an appropriately designed mechanism.[424]

[418] Ex. 150, p. 3, ll. 1-20.
[419] *Id*, p. 2, ll. 14-20.
[420] Ex. 42, p. 3, ll. 8-22.
[421] Exhibit 43, Ronald A. Klote Surrebuttal and True-Up Direct Testimony, p. 2, ll. 5-22.
[422] Exhibit 30, Darrin Ives Rebuttal Testimony, p. 10, ll. 1-10.
[423] Exhibit 23, Kevin D. Gunn Surrebuttal Testimony, p. 2, ll. 13-21 through p. 3, ll. 1-18.
[424] Ex. 43, p. 3, ll. 1–21.

A prospective mechanism permits the Commission to establish the review conditions now, rather than leaving customers dependent solely on later litigation about whether rates have become unreasonable. Staff does not contend that every dollar of additional LLPS revenue is excessive profit or that the authorized ROE guarantees a particular annual result. The recommended calculation tests actual companywide earnings before any customer share is recorded.[425]

I. The Ameren Missouri Mechanism directly answers EMM's principal design objection.

EMM argues that earnings cannot be measured by isolating one customer class because total financial performance reflects revenues, operating expenses, depreciation, taxes, financing costs, and investment across the utility.[426] The Ameren Missouri mechanism accommodates that concern. LLPS revenue growth is the threshold condition; the company's overall earned ROE determines the amount subject to sharing.[427]

The distinction matters. Actual LLPS base-rate revenues must first exceed the LLPS base-rate revenues reflected in the revenue requirement used to establish applicable base rates. If they do not, no sharing occurs. If they do, the mechanism compares companywide earned ROE with its specified benchmark, multiplies the positive difference by the equity portion of rate base, grosses that amount up for income taxes, and assigns 65 percent to customers through a regulatory liability. Additional LLPS revenues alone do not create the

[425] Ex. 150, p. 3, ll. 6-17 and Schedule KKB-s2.
[426] Ex. 42, Klote Rebuttal, pp. 3–5.
[427] Ex. 150, p. 3, ll. 6-17 and Schedule KKB-s2.

liability. Nor does the mechanism require proof that each dollar of excess companywide earnings can be traced exclusively to a particular LLPS customer.[428]

Mr. Ives confirmed the common structure at the October 13 on-the-record presentation. He described the LLPS Agreement and Ameren Missouri mechanisms as having "a two-trigger approach."[429] He also acknowledged that both use surveillance reporting, compare earned returns against a benchmark, and provide a 65/35 split once sharing begins.[430] The existence of that common structure supports Staff's proposal; it does not establish that the settlement's departures are warranted.

The Commission should preserve both tests. Google previously objected to conditioning sharing on LLPS revenues exceeding the amount reflected in base rates.[431] Staff's recommendation retains that condition because it is part of the Ameren Missouri design and ties this temporary protection to the large-load growth concern presented here. At the same time, the second test answers EMM's concern that growth may bring costs that offset additional revenues.[432]

II. The Commission should retain the 65 percent customer share without adding an unnecessary deadband.

Ms. Bolin identifies two material differences between Ameren Missouri's mechanism and the Kansas approach: Kansas returns only 50 percent of overearnings and permits eleven adjustment items, while the Ameren Missouri mechanism uses a larger customer

[428] Ex. 150, Schedule KKB-s2.
[429] Unofficial Tr. Vol. 12, p. 76, ll. 2-22.
[430] *Id*.
[431] Exhibit 454, True-Up Rebuttal Testimony of Dr. Carolyn Berry, p. 7, ll. 1-15.
[432] Ex. 150, p. 3, ll. 6-17.

share and narrowly limited adjustments.[433] She recommends Ameren Missouri's design to provide consistency between Missouri's two largest electric utilities.[434]

Mr. Klote put forward a proposal on behalf of EMM calling for a 50/50 sharing ratio.[435] Dr. Berry's proposal called for a 75 percent customer share above a 25-basis-point allowance.[436] The LLPS Agreement instead uses a 65 percent customer share but permits EMM to retain all earnings up to 20 basis points above the authorized ROE. These are distinct proposals. A familiar sharing ratio does not make the settlement identical to Ameren Missouri's mechanism.

The added allowance has a direct economic effect. Even after LLPS revenues exceed the base-rate amount, customers receive nothing under the settlement until earned ROE exceeds the authorized ROE by more than 20 basis points. EMM retains that entire first increment. Above the threshold, customers share only in earnings beyond the increment; they do not recover the withheld share when the threshold is crossed. That follows from the express calculation within Exhibit D attached to the LLPS Agreement.

For illustration only, assume both alternatives use the same 10 percent benchmark, EMM earns 10.20 percent, and the LLPS revenue trigger is satisfied. Staff's design shares 65 percent of the tax-grossed-up 0.20 percentage-point return on the equity portion of rate base. The LLPS Agreement shares zero.

[433] Ex. 150, p. 4, ll. 1-11.
[434] *Id*.
[435] Ex. 43, p. 8, ll. 10–22.
[436] Ex. 453, Surrebuttal Testimony of Dr. Carolyn Berry, p. 4, ll. 14–20.

Mr. Ives described the 20-basis-point allowance as a negotiated term and explained that EMM sought to avoid undue incentive differences among its jurisdictions. He also acknowledged that EMM had earlier advanced a different sharing percentage without a deadband.[437] Those explanations establish how the parties reached their bargain. They do not demonstrate why Missouri customers should surrender otherwise shareable earnings.

The Ameren Missouri design already preserves an incentive: EMM retains 35 percent of earnings subject to sharing. It also accommodates negative cost and revenue developments through the companywide earnings calculation.

III. The Commission should preserve limited adjustments and future control over amortization.

The Ameren Missouri mechanism begins with the familiar surveillance reporting framework and permits removal of capital investment or expense the utility has committed not to recover or the Commission has disallowed, together with reclassification of out-of-period items. It expressly excludes updates, removal of one-time or nonrecurring expenses, weather normalization, and other ordinary test-period normalization or annualization adjustments. This keeps the annual calculation focused on actual results instead of turning it into another general rate case.[438]

Mr. Klote proposed reliance on existing surveillance reports and actual historical financial results, with narrowly limited adjustments and no ordinary normalization or

[437] Unofficial Tr. Vol. 12, p. 77, ll. 5 through p. 78., ll. 6
[438] Ex. 150, Schedule KKB-s2.

annualization, in his testimony.[439] Thus, Staff's recommendation does not impose an unfamiliar administrative framework on EMM.

The LLPS Agreement adds separate PISA-related amortization treatment and an express CWIP provision. Mr. Ives defends the PISA provision as aligning customer credits with recovery of the associated deferrals and defends the CWIP provision as aligning surveillance calculations with Commission-approved treatment of qualifying natural-gas construction.[440]

Staff recommends retaining the Ameren Missouri language. It already leaves the reasonable amortization period for the regulatory liability to the Commission in a future rate case. That reservation allows the Commission to consider the actual balance and relevant recovery circumstances on a developed record, rather than binding a future Commission to the settlement's separate PISA alignment rule. Likewise, the Commission should use the surveillance-based rate-base definition adopted for the Ameren Missouri mechanism and preserve legally required treatment of Commission-approved investments. It should not add a separate category of assumed or projected CWIP merely because a project may qualify for future recovery. The statutory eligibility of a project and the amount properly included in a particular year's earned-return calculation are separate questions. The Commission can resolve implementation disputes through the mechanism review process without importing Exhibit D's additional substantive language into Staff's proposal.

[439] Ex. 43, pp. 9–11.
[440] Tr. Vol. 12, p. 78, ln. 7 through p. 80, ll. 18.

Conclusion

The Ameren Missouri precedent is persuasive because it addresses the same kind of growth-related uncertainty through a concrete, administrable design. Staff does not assert that approval of another utility's settlement automatically dictates the outcome here. Ms. Bolin independently recommends that design in this record.[441]

The Commission should order EMM to implement Schedule KKB-s2 with the substitutions necessary to apply it to EMM and Schedule LLPS. The order should expressly identify EMM's applicable ROE benchmark and use the same continuing-benchmark convention stated in footnote 1 of Schedule KKB-s2. It should not transplant Ameren's numerical ROE or its unrelated rate-case number into an EMM compliance calculation.

The order should retain the following operative requirements: annual ERS filings by March 31; discovery and review rights; Staff and OPC identification of disagreements by May 31, subject to good-cause extensions; EMM responses by June 30 with corresponding extensions; and Commission resolution of remaining disputes with an intended August 31 resolution date. The filing should identify the LLPS base-rate revenues actually received and the corresponding LLPS revenues reflected in the rate case or cases establishing base rates in effect during the review year.[442]

If the revenue trigger is satisfied, the positive difference between EMM's earned ROE and the specified benchmark should be multiplied by the equity portion of rate base, grossed up for income taxes, and multiplied by 65 percent. EMM should record that

[441] Ex. 150, pp. 2-4 and Schedule KKB-s2.
[442] Ex. 150, Schedule KKB-s2.

customer share as a regulatory liability. The portion above 50 percent should benefit low-income customers and should exclude funding of MEEIA low-income programs. The subsequent rate case should establish a reasonable amortization period. No additional 20-basis-point allowance should apply.[443]

The order should preserve the Ameren Missouri mechanism's limited adjustments, its treatment of the sharing deferral in surveillance reporting, and its termination after new rates become effective following the next general rate case unless the Commission extends it. It should also retain the opportunity to request reinstatement upon notice of a new qualifying large-load customer, with the notice reference conformed to EMM's applicable requirements. The order should identify the first covered period expressly so that its prospective operation and the treatment of any partial calendar year are unambiguous.[444]

Travis J. Pringle

Issue 42. MEEIA Margin Rates

A. What methodology should be used to calculate the net marginal rate for each rate class?

The Commission should adopt the methodology employed by EMM in its direct filing to calculate the net marginal rates for each applicable rate class, with the final calculations updated to reflect the rates approved by the Commission in this proceeding. Staff does not oppose EMM's proposed methodology. The remaining task is to ensure that the resulting net

[443] *Id*.
[444] *Id*.

marginal rates reflect the Commission's final rate determinations rather than the proposed rates used in EMM's initial calculations.[445]

Net marginal rates are used in connection with the Missouri Energy Efficiency Investment Act ("MEEIA") to determine the contribution to utility margins associated with customers' electricity consumption. Because energy efficiency programs reduce electricity consumption, the applicable net marginal rate is relevant to determining the margins associated with those reductions. Accordingly, the calculation should reflect the rates customers will actually pay, rather than rates that may change during the course of a general rate proceeding.

EMM witness Graham Jaynes provided net marginal rate calculations in Schedule GAJ-12 to his direct testimony. Those calculations were based on EMM's proposed rates and included monthly and annual values for the Small General Service, Medium General Service, Large General Service, and Large Power Service classes.[446] However, Jaynes acknowledged that net marginal rates have traditionally been updated at the conclusion of a rate case, after final rates have been determined.[447] Thus, while Schedule GAJ-12 provides the basis for the calculation, its results are necessarily preliminary.

The inclusion of these calculations in EMM's direct filing is also consistent with the approach established in EMW's prior rate case, Case No. ER-2024-0189. In that

[445] Staff's Statement of Positions at 39, Case No. ER-2026-0143 EFIS Item 295.
[446] Ex. 33, Direct Testimony of Graham A. Jaynes, pg. 53, lns. 16–19 & sched. GAJ-12, Case No. ER-2026-0143, EFIS Item 13.
[447] Id. at 53:20–54:4.

proceeding, the parties agreed that EMW would provide net marginal rate calculations in future rate cases through operable spreadsheets, with an explanation in direct testimony.[448] Although Jaynes acknowledged that this agreement did not directly obligate EMM, the Company voluntarily provided the calculations in this case.[449] This approach permits the methodology to be reviewed during the proceeding while preserving the established practice of calculating final net marginal rates after the Commission has determined the applicable rates.

Staff does not oppose EMM's methodology, and no modification to that methodology is necessary to resolve this issue. The Commission should therefore direct EMM to recalculate the net marginal rates for each applicable rate class, using the methodology reflected in Schedule GAJ-12 and the final rates approved in this proceeding. This will provide a consistent basis for calculating MEEIA-related margins while ensuring that those calculations reflect the rates ultimately authorized by the Commission.

Mark Johnson

CONCLUSION

Staff recommends that the Commission adopt Stipulations I-IV and accept Staff's positions and recommendations contained in the Remaining Issues section of this brief. Such an order will be aligned with past Commission decisions, and be consistent with the Commission's treatment of similar issues for the other regulated electric utilities.

[448] Id. at 53:20–54:2 (describing the settlement provision in Case No. ER-2024-0189).
[449] Id. at 54:1–4.

WHEREFORE, on account of all the foregoing, Staff prays that the Commission will issue its findings of fact and conclusions of law, determining just and reasonable rates and charges for EMM as recommended by the Staff herein; and granting such other and further relief as is just in the circumstances.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been transmitted by electronic mail to counsel of record on this 6th day of November 2026.

/s/ Tracy D. Johnson

ISSUES BY STIPULATION

I. Auditing Stipulation: Signed by EMM and Staff.[1] Not opposed by OPC, Renew, or Google.

MECG opposed for the limited purpose of preserving (in part) Issue 17 A *Depreciation – Which depreciation rates should be used?*[2]

2. Revenues and Billing Determinants

A. What level of billing units and normalized revenues should be used in calculating rates?
   i. What update period adjustment should be used in calculating normalized billing units, revenues, and rates?
   ii. What rate switcher and Large Power Service customer annualization adjustment should be used?
   iii. What weather normalization adjustment should be applied?
   iv. Should the blocking percentage for the actual blocks and the weather normalized blocks be the same?
   v. What 365-day adjustment should be used?
   vi. What energy efficiency adjustment should be used?
   vii. What growth adjustment should be used, and what counts should be used to calculate normal use per customer and customer growth?
   viii. What non-Missouri kilowatt hour ("kWh") adjustment should be used in calculating normalized billing units?
   ix. Should the definitions of bill count and customer charge counts be added to EMM's tariff?
   x. For normalization of retail revenues and billing determinants, should customer charge count or bill count be utilized?
   xi. Should the Company be compelled to provide both bill count and customer charge count in future rate cases.
   xii. What is the normalized revenue and kWh for Large Power Service ("LPS") customers?

3. Other Revenues

B. What level of forfeited discount, commonly referred to as late payment revenue, should be included in the cost of service?
C. Should late payment fee revenue be increased by a proportionate amount of the revenue requirement increase authorized by the Commission in this case, commonly referred to as a "late payment fee factor-up"?

[1] EFIS Item No. 311 Partial Stipulation and Agreement.
[2] EFIS Item No. 325 MECG Response to Commission's Order Shortening Time to Object to Stipulation and Agreements.

4. Wholesale Transmission Revenue Credit

A. Should the Commission accept EMM's revenue reduction to adjust utility transmission revenues in its cost of service to reflect Commission-authorized versus Federal Energy Regulatory Commission ("FERC") authorized returns on equity?

6. Transmission Expense

A. Should the requirement for the Transource adjustment be discontinued?

7. Payroll, Benefits, and Incentive Compensation (includes OPEB Stipulation)

A. What is the appropriate ratio of Operations and Maintenance ("O&M") expense to be used in calculating payroll, benefits, and payroll tax expense?
B. What level, if any, of long-term stock-based incentive compensation should be included in the cost of service?
C. What level of capitalized short-term incentive compensation based on earnings should be removed from plant in service?
D. What level of severance payments should be included in the cost of service?
E. What level of pension and other post-employment benefit ("OPEB") expense should be included in the cost of service?
F. What level of supplemental executive retirement plan ("SERP") expense should be included in the cost of service?

8. Maintenance and Operating Expense

A. What level of meter replacement O&M costs should be included in the cost of service?
B. What level of outside services expense should be included in the cost of service?
C. What level of affiliate transaction expenses should be included in the cost of service?

9. Amortizations and Expired Amortization Tracker

A. What level of Demand Side Management pre-MEEIA opt-out amortization should be included in the cost of service?
B. What level of prospective tracking amortization should be included in the cost of service?

10. Advertising, Dues, and Donations

A. What level of Edison Electric Institute ("EEI") dues should be included in the cost of service?

11. Customer Accounts Expense

A. Should bad debt expense be increased by a proportionate amount of the revenue requirement increase authorized by the Commission in this case, commonly referred to as a "bad debt factor-up"?

12. Regulatory Assessments, Rate Case Expense, and Local Taxes

A. What level of rate case expense, if any, should be allowed in the revenue requirement?

13. Common Use Billings

A. Should the Uplight software be billed to Evergy's Kansas regulated entities?

B. What Uplight costs, including plant, reserve, amortization expense, and common use billings, should be included in the revenue requirement, and how should those costs be allocated and recovered?

14. Property Tax

A. What is the appropriate level of Missouri property tax to be included in rates?
B. What base level of property taxes should the Commission approve for tracking purposes?
C. What level of property tax tracker rate base amount and amortization should be included in the cost of service?

15. Income Taxes

A. How much income tax expense should be included in rates?
   ii. What amount of research and development tax credits should be included in income tax expense?
   iii. What amount of ongoing nuclear production tax credit benefits realized should be included in income tax expense?
B. Should the Commission approve a tracker for Inflation Reduction Act tax benefits?
   i. If a tax tracker should be approved, should the differences between actual tax benefits and tax benefits included in income tax expense be subject to carrying costs, and if so, what is the appropriate carrying cost to accrue?
D. Should an Accounting Authority Order ("AAO") be issued to defer the sale of tax benefits after the true-up date but prior to the effective date of rates?

17. Depreciation

A. Which depreciation rates should be used? (in part, part went to hearing)
B. Should terminal net salvage be included in depreciation rates?
C. What general plant amortization reserve deficiency adjustment should be made?
D. Should rates reflect the ongoing amortization of a cost of removal asset?
E. Should EMM recover future retirement costs in current rates?

18. Plant in Service Accounting

A. What projects should be reflected as eligible for plant in service accounting ("PISA")?
C. What amount of PISA amortization should be included in expense?
D. Should EMM's plant-in-service reporting requirements be modified from those in the Stipulation and Agreement approved in Commission Case No. ER-2022-0129, and if so, what modifications should be made?

19. Distribution Investment

C. Is EMM in compliance with the Commission's vegetation management rule, and if not, what should the Commission order?
D. Should EMM be required to compare the benefit of increased vegetation management against additional investment in its lateral improvement program?

20. Rate Base Components

A. What level of EEI prepayments should be included in rate base?

D. What treatment should apply to the pension asset in rate base?
G. What level of coal inventory should be included in rate base?

21. Jurisdictional Allocations

A. What jurisdictional demand and energy allocation factors should be used?
B. How should the allocations be determined for the various elements of the cost of service?
C. Should a portion of plant, reserve, and depreciation expense of the Greenwood solar facility be allocated to EMM?

22. Fuel Adjustment Clause — Structure and Base Factor

A. Should the Commission authorize EMM to continue its FAC?

23. Fuel Adjustment Clause — Included Costs

B. What SPP charge types should be included in the FAC?

24. Fuel Adjustment Clause — Tariff Language

A. Should EMM include a new definition in the FAC tariff sheets for retail revenue and accounts 440 through 444?
B. Should the definition of fuel residuals under FERC subaccount 501400 in the FAC tariff sheets be changed?
C. Should the extraordinary costs language proposed by Staff be reflected in EMM's FAC tariff?
D. Should EMM change the Emissions definition Factor R to Emissions and Environmental credit accounts, subaccounts 411.8, 411.9, 411.12 and 411.13?
E. Should language be added to the FAC tariff sheets to address fuel hedging?

26. Rules and Regulations Tariff

A. Should the Commission approve EMM's proposed tariff changes regarding its Rules and Regulations inclusive of modifications identified in the error log?

27. Estimated Billing and Interval Data

A. What updates, if any, to EMM's tariffs should occur to address energy interval estimation?
B. What interval estimation threshold is appropriate for designation of an estimated bill and how should intervals be estimated?
C. What records should be retained for missing or estimated interval data?
D. What reporting requirements should be implemented for missing or estimated interval data?
E. Should EMM's estimation procedure defined in the EMM tariff, include thresholds for automated and manual reviews of estimations?

30. Other Rate Schedules

B. Should obsolete residential rate schedules and the Underutilized Infrastructure Rider be removed from the EMM tariff book?

34. Storm Reserve

A. Should a storm reserve be established in this case?
B. If approved, how much should be included in the cost of service?

35. Injuries and Damages

A. Should an injuries and damages reserve be established in this case?
B. If approved, how much should be included in the cost of service?

II. <u>OPEB Stipulation</u>: Signed by EMM and Staff. Not opposed by OPC, Renew, Google, or MECG. [3]

7. Payroll, Benefits, and Incentive Compensation (includes Auditing Stipulation)

A. What is the appropriate ratio of Operations and Maintenance ("O&M") expense to be used in calculating payroll, benefits, and payroll tax expense?
B. What level, if any, of long-term stock-based incentive compensation should be included in the cost of service?
C. What level of capitalized short-term incentive compensation based on earnings should be removed from plant in service?
D. What level of severance payments should be included in the cost of service?
E. What level of pension and other post-employment benefit ("OPEB") expense should be included in the cost of service?
F. What level of supplemental executive retirement plan ("SERP") expense should be included in the cost of service?

III. <u>Non-C&I Stipulation</u>: Signed by EMM and Staff. Not opposed by OPC, Renew, Google, or MECG.[4]

2. Revenues and Billing Determinants

A. What level of billing units and normalized revenues should be used in calculating rates?
   xiii. What Economic Development Rider discount annualization should be applied?
   xiv. What amount of gross up for revenue requirement should be applied to Economic Development Rider discount amount.

28. Residential Rate Design

A. What should the residential customer charge be set at in this case?

29. Non-Residential Rate Design

C. How should standby service rates be modified to include a minimum demand alternative or modified as appropriate?

[3] EFIS Item No. 310 Non-Unanimous Stipulation and Agreement Regarding Pensions and Other Post-Employment Benefits.
[4] EFIS Item No. 312 Partial Stipulation and Agreement - Non-C&I Rate Design.

IV. <u>Programs Stipulation</u>: Signed by EMM, Staff and Renew. Not opposed by Google or MECG. OPC opposed (in part) specifically to Issue 16 E *Income-Eligible Programs – Should the Commission approve the creation of a low-income rate or assistance program that waives EMM's customer charge for qualifying customers in this case, or should such a program continue to be developed in the Affordability Workshop? – i. If such a program is approved, should late fees be waived for qualifying customers? – ii. If such program is approved, how should the waived revenues be recovered?*[5]

16. Income-Eligible Programs

A. What level of Critical Medical Needs and Rehousing Programs expense should be included in the revenue requirement?
B. What level of economic relief pilot program ("ERPP") expense should be included in the revenue requirement?
C. Should the pilot designation be removed from EMM's ERPP tariff?
D. Should EMM be required to provide a summary of the Rehousing Program administration, reporting, and evaluation by email to Staff and the Office of the Public Counsel at the conclusion of each year of the Program as described in its currently approved tariff?
E. Should the Commission approve the creation of a low-income rate or assistance program that waives EMM's customer charge for qualifying customers in this case, or should such a program continue to be developed in the Affordability Workshop?
   xiii. If such a program is approved, should late fees be waived for qualifying customers?
   xiv. If such program is approved, how should the waived revenues be recovered?
F. Should EMM be required to file quarterly Rehousing Program reports in EFIS in addition to the existing year-end report?
G. What changes, if any, should be made to the ERPP tariff to permit broader enrollment or to allow unused program funding to be transferred to other income-eligible programs?
H. What level of Low-Income Weatherization Program expense, if any, should be included in the revenue requirement?

[5] EFIS Item No. 320 Non-Unanimous Programs Stipulation and Agreement.

38. Energy Burden Analysis

A. Should the Commission order a 3rd party energy burden analysis for EMM that does not exceed $150K in costs?

39. Green Button Connect

A. Should the Commission order EMM to implement Green Button Connect ("GBC") in this rate case?

B. If the Commission orders EMM to implement GBC, should the Commission order the tariff proposed by Renew Missouri related to GBC?

C. If the Commission orders EMM to implement GBC, should the Commission adopt Renew Missouri's revenue requirement recommendation?

D. If the Commission orders EMM to implement GBC, should Renew Missouri's recommended revenue requirement for studying a regional data hub be ordered by the Commission?

40. Customer Battery Programs

A. Should the Commission order the adoption of Renew Missouri's proposed battery programs?

41. Income-Eligible Solar Program

A. Should the Commission order the adoption of Renew Missouri's proposed evaluation and expansion of the Income-Eligible solar program?

V. <u>LLPS Stipulation</u>: Signed by EMM and Google.[6] Opposed by Staff[7] and OPC[8]. Opposed by MECG for the limited purpose of preserving the right to take a position on the issues included within its post-hearing briefs.[9] Renew remained silent in response to this stipulation.

3. Other Revenues

A. What is the appropriate level of net revenue to reflect in the cost of service and other models for Large Load Power Service ("LLPS") and other large customers?

i. What is the appropriate revenue adjustment for expected future revenues from Schedule LLPS customers in the cost of service model?

[6] EFIS Item No. 314 (Highly Confidential) and 317 (Public) LLPS Partial Stipulation and Agreement.
[7] EFIS Item No. 318 Staff Objection to LLPS Partial Stipulation and Agreement (Public and Highly Confidential).
[8] EFIS Item No. 324 Public Counsel's Opposition to LLPS Settlement (Public and Highly Confidential).
[9] EFIS Item No. 325 MECG Response to Commission's Order Shortening Time to Object to Stipulation and Agreements.

5. Fuel and Purchased Power

A. What should be adopted as the variable fuel and purchased power cost for this case?
B. What fuel prices should be included in the cost of service?
C. What normalized market prices should be used to determine the revenue requirement in this case?
D. What level of Transmission Congestion Rights ("TCR") revenue, not TCR margin, should be included in the cost of service?

22. Fuel Adjustment Clause — Structure and Base Factor

B. Should the general construct of EMM's FAC be changed?
C. What value should the FAC base factor be set at the conclusion of this case?
D. What sharing ratio between EMM and its customers should the Commission order as an incentive mechanism in EMM's FAC?

23. Fuel Adjustment Clause — Included Costs

A. What SPP transmission costs should be included in the FAC?
C. What FAC subaccounts should be included in the FAC?
D. Should EMM include long-term capacity purchases and sales for recovery in its FAC?

25. Fuel Adjustment Clause — Large Load Power Service

A. Should changes be made to the FAC to address LLPS customers?
B. What, if any, new FAC reporting requirements should the Commission order?
C. Should EMM have a separate FAC base factor for LLPS customers?

37. Revenue Sharing

A. Should the Commission implement a mechanism to review or share earnings attributable to Schedule LLPS customers, and if so, how should it be designed?

VI. <u>Rate Design Stipulation</u>: Signed by EMM and MECG.[10] Google did not oppose.

Opposed by Staff[11] and OPC.[12] Renew remained silent in response to this stipulation.

29. Non-Residential Rate Design

A. Should the rates of the non-residential non-lighting customers be restructured in this case?
   i. What are the appropriate periods for each time-related element?
   ii. Should the Large General Service ("LGS") and Medium General Service ("MGS") classes be subject to reactive demand charges?
   iii. What are the appropriate charges for each rate element for each class?

[10] EFIS Item No. 313 Non-Unanimous Partial Settlement - Rate Design.
[11] EFIS Item No. 322 Staff Objection to Non-Unanimous Partial Settlement - Rate Design.
[12] EFIS Item No. 323 Public Counsel's Opposition to Non-Unanimous Partial Settlement - Rate Design.

iv. Should EMM be ordered to promptly conduct a billing determinants and customer impact study?
v. What customer education is appropriate?
vi. What date should restructured rates take effect?

B. Should the non-residential non-lighting opt-in time based rates proposed by EMM be implemented?

30. Other Rate Schedules

A. How should all other applicable rates in this case be increased, including lighting, Large Load Power Service, Electric Vehicle Charging, and Time Related Pricing, if applicable?
   i. Should the TRP (Time Related Pricing) rate schedule be eliminated?
   ii. Should Schedule LLPS rates be increased in this proceeding, and if so, by how much?

32. Revenue Apportionment and Implementation

A. How should revenue responsibility, including any net revenues from LLPS customers and any reduction to revenues from any income-eligible customer discounts, be apportioned among the customer classes, if at all?
   i. What is the appropriate classification of customer-classified distribution system cost of service for any class cost of service study relied upon in this case?
   ii. What is the appropriate allocation of production-related cost of service for any class cost of service study relied upon in this case?

B. How should customer affordability, including for low- and moderate-income households, be reflected in the rates ordered in this case?

C. Should EMM's surrebuttal proposal to implement the rate increase by bill cycle in this case be permitted?

D. How should revenue responsibility for construction work in progress be assigned or allocated among the customer classes?