BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

INITIAL POST-HEARING BRIEF OF EVERGY METRO, INC.

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INTRODUCTION AND ISSUES ROADMAP

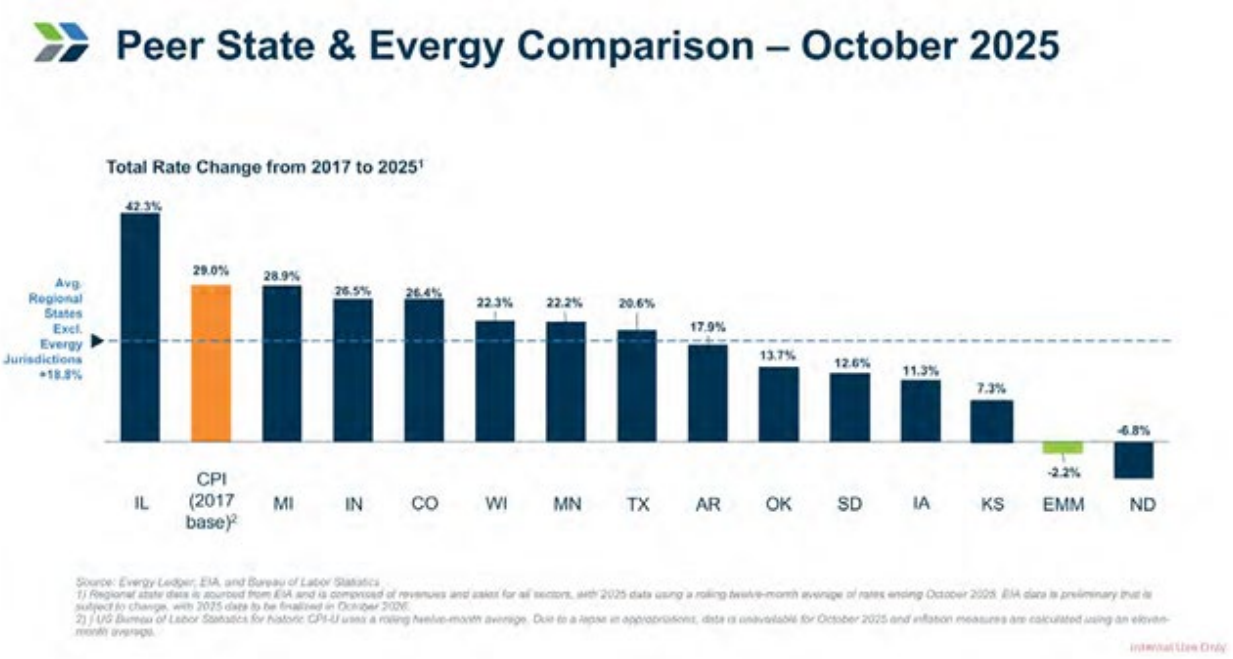
Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("EMM" or the "Company") respectfully submits this *Initial Post-Hearing Brief* ("Brief") to the Missouri Public Service Commission ("Commission").[1]

This rate case is about the affordable, reliable, and sustainable service the Company's customers expect and deserve. In 2025, the Company had the 16th lowest average residential bill among the 100 largest investor-owned electric utilities with bundled sales.[2] On February 6, 2026, the Company filed its first general rate case in four years, as required by the statute governing its fuel adjustment clause ("FAC").[3] In the four years since its last rate case, the Company has focused on affordability, reliability, and sustainability for all customers in its service territory. It continues to deliver that service through the investments in this case.

"Evergy Missouri Metro's total rates decreased by 2.2% over the period 2017 through October 2025, while the rates of electric utilities in peer states have increased by an average of 18.8%," during a period in which inflation increased by approximately 29%.[4] Figure 1, from the direct testimony of Kevin Gunn (Vice President, Regulatory and Government Affairs), shows that comparison state by state.

[1] 20 CSR 4240-2.080; Order Setting Procedural Schedule and Directing the Filing of Dates for Local Public Hearings at ¶ 3(D) (Mar. 18, 2026) ("Procedural Order").
[2] See Ex. 31, Ives Surrebuttal at 3 (Energy Information Administration Form EIA-861 data).
[3] See Section 386.266.5(3) (Rate schedules for interim energy charges or periodic rate adjustment); 20 CSR 4240-20.090(10). All statutory citations in this Brief are to the Revised Statutes of Missouri (2016), as amended.
[4] See Ex. 21, Gunn Direct at 12–13.

Figure 1. Total Rate Change, 2017 through October 2025[5]



The Company filed this case originally requesting a revenue requirement increase of $140.4 million, or 15.19%.[6] By the June 30, 2026, true-up date, the request stood at $162.6 million.[7] As a result of the six stipulations and agreements detailed in Subsection A, the Company now asks for $88.9 million, down to a little over half of that true-up request and an increase of less than 10%.[8] Subsection B shows how the Company's $88.9 million figure is comprised. If approved, the $88.9 million increase in the revenue requirement would result in a cumulative 9.6% change since the end of 2017, equal to a 2.3% annual increase since the 2022 rate case and a 1.0% annual increase since 2017.[9] This is well below regional peer utilities and far below inflation over the same periods.

If granted, the requested increase recovers the cost of new infrastructure investments that enhance reliability and customer service. These new infrastructure investments are needed to replace aging distribution assets, meet the Southwest Power Pool's ("SPP") heightened planning

[5] Id. at 12 (Figure 2).
[6] Ex. 33, Jaynes Direct at 47.
[7] See Ex. 43, Klote Surrebuttal/True-Up Direct at 17.

reserve margin requirements, and serve growing demand. As the record demonstrates, reliability and affordability are inseparable. Deferring necessary investment creates a cycle of reactive, more expensive maintenance and outage costs that, ultimately, burden customers with higher rates. The Company's cost recovery mechanisms ensure timely cost recovery, reduce rate volatility, and support prudent long-term planning for the benefit of all customers. Those mechanisms include plant in service accounting ("PISA") treatment, critical infrastructure protection and cyber security tracker, and construction work in progress ("CWIP"). Affordable, reliable, and sustainable service also depends on a financially sound utility. The Company must raise capital for its investment plan as inflation and interest rates rise, as Section III explains. Without an adequate return on equity ("ROE"), the Company cannot build the infrastructure its customers need, fund its customer programs, or carry out the balanced large load framework the Commission approved in November 2025.

In this Introduction and Issues Roadmap, Subsection A describes the six stipulations and agreements the Company negotiated with the other parties in this case. Subsection B describes the Company's requested revenue requirement increase at the June 30, 2026, true-up date as compared to the adjusted amount and positions to which the Company then agreed, to promote reasonable settlement. Subsection C summarizes the contested issues, unresolved by any stipulation, that remain for the Commission to decide based on the record evidence as a whole.

[8] On the revenue base implied by Mr. Jaynes's 15.19% ($140,353,035 ÷ 0.1519, or $924.0 million), $88,902,805 is 9.6%. On Staff's true-up non-LLPS revenues of $902,389,146, it is 9.9%. See Partial Stipulation and Agreement at ¶ 2.

[9] See supra note 8. Annualized, a 9.6% increase is about 2.3% a year over the four years since rates from the Company's 2022 rate case took effect and about 1.0% a year over the nine years since the end of 2017.

The contested issues are then further detailed in this Brief's subsequent Argument sections, including responses to questions from the Commissioners and the Regulatory Law Judge ("RLJ") during this case's evidentiary hearing of October 5-9 and 13, 2026.

A. Stipulations and Agreements

The Company and other parties—principally Commission Staff—filed six stipulations and agreements in this case from October 2 through October 7, 2026.[10]

Pensions Stipulation and Non-C & I Rate Design Stipulation: On October 2, 2026, the Company and the Commission Staff ("Staff") filed the Non-Unanimous Stipulation and Agreement Regarding Pensions and Other Post-Employment Benefits ("*Pensions Stipulation*").[11] No party objected. The same day, the Company and Staff filed the Partial Stipulation and Agreement – Non-C&I Rate Design ("*Non-C&I Rate Design Stipulation*"), which keeps the residential customer charge at $12.00, among other provisions.[12] No party objected to this stipulation either. The Commission should therefore treat both as unanimous and approve them.[13]

Partial Stipulation and Agreement: Also on October 2, 2026, the Company and Staff filed a partial stipulation ("*Partial Stipulation*"), resolving a multitude of issues "in exchange for a $46 million increase in Staff's revenue requirement."[14] Renew Missouri Advocates d/b/a Renew Missouri ("Renew Missouri"), the Office of the Public Counsel ("OPC"), and Google LLC ("Google") did not object to it. Midwest Energy Consumers Group ("MECG") objected only to

[10] Under the Commission's rules, a party has seven days to object to a nonunanimous stipulation, and the objection must identify each provision objected to and give a reason. If no party objects in time, the Commission may treat the stipulation as unanimous. If a party objects in time, the stipulation becomes a position of its signatories, and all issues remain for determination after hearing. See 20 CSR 4240-2.115(2)(B)–(D).
[11] See Pensions Stipulation at ¶¶ 1–19 (Oct. 2, 2026).
[12] See Non-C&I Rate Design Stipulation at ¶¶ 1–17 (Oct. 2, 2026).
[13] See 20 CSR 4240-2.115(2)(C); Order Shortening Time to Object to Stipulation and Agreements at ¶ 1 (Oct. 5, 2026).
[14] See Partial Stipulation at ¶ 1.

the depreciation rates for Iatan Unit 1 and La Cygne Unit 2 under Issue 17.A, which is addressed in Section XII.[15]

Programs Stipulation: On October 7, 2026, the Company, Staff, and Renew Missouri filed the Non-Unanimous Programs Stipulation and Agreement ("*Programs Stipulation*"), which resolves the Company's customer programs portion of this case. OPC objected only to the absence of a customer charge waiver program under Issue 16.E, which is addressed in Section IX.[16]

Rate Design Settlement: On October 5, 2026, the Company and MECG filed the Non-Unanimous Partial Settlement – Rate Design ("*Rate Design Settlement*"). Staff and OPC objected to most of its terms.[17] However, one provision obtained no objection: the elimination of the Hours Use rate structure, with a winter on-peak demand period beginning at 7:00 a.m. The Company therefore requests the Commission to adopt that provision which resolves Issues 29.A and 29.A.i.[18] The implementation date, which Staff contests, is addressed in Section X.

LLPS Stipulation: The same day, the Company and Google filed the LLPS Stipulation and Agreement ("*LLPS Stipulation*"). It addresses the Company's Large Load Power Service ("LLPS") tariff ("Schedule LLPS"), as well as the revenue requirement and FAC, among other provisions.[19] Staff and OPC objected to the LLPS Stipulation, and MECG objected only to

[15] See Amended Joint List and Order of Issues and Witnesses, and Order of Cross-Examination (Oct. 5, 2026) ("Amended Joint List"); MECG Response at ¶ 5.
[16] See Programs Stipulation at ¶¶ 1–18.
[17] See Rate Design Settlement at 1–5 & ¶ 11 (Oct. 5, 2026); Staff Objection to Non-Unanimous Partial Settlement – Rate Design (Oct. 7, 2026) ("Staff Rate Design Objection"); Public Counsel's Opposition to Non-Unanimous Partial Settlement – Rate Design at ¶¶ 1–4 (Oct. 7, 2026) ("OPC Rate Design Opposition").
[18] See Rate Design Settlement at 2; Staff Rate Design Objection at ¶ 4; OPC Rate Design Opposition at ¶ 4; Ex. 33, Jaynes Direct at 18, 19, 23, 24; Ex. 138, Sarah Lange Rebuttal at 62; Tr. Vol. 12 at 170:13–171:9 (Sarah Lange). Official transcripts of the October 13, 2026 hearing (Vol. 11) and on-the-record presentation (Vol. 12) had not been filed as of 3:00 p.m. on November 6, 2026. Citations to those volumes are to the unofficial transcripts, EFIS Items 334 and 335, filed October 26, 2026. If the official transcripts differ in substance from the passages cited, the Company will file an errata correcting the affected citations.
[19] See LLPS Stipulation at ¶¶ 1–13 (Oct. 5, 2026).

preserve its ability to take positions on these issues in its post-hearing briefs.[20] Velvet Tech Services, LLC ("Velvet Tech") did not object to the LLPS Stipulation or to any other agreement. Similarly, one provision obtained no objection: the use of Staff's 31.8% pass-through percentage for SPP transmission costs in the FAC.[21] The Company therefore requests the Commission to adopt that term, which resolves Issue 23.A of the Amended Joint List.

In an effort to organize and simplify, the Company has summarized the stipulated and remaining issues below. Table 1 lists the issues each agreement resolves as well as the remaining contested issues (addressed fully in Sections I–XII below).[22] Table 1A states in plain terms what each agreement accomplishes. Additionally, Appendix A provides a summary of each issue resolved by agreement, alongside the positions of other parties and the outcome the Company requests. The Joint List of Status of Issues, filed concurrently with this Brief under the Commission's October 27, 2026, order, states the status of each issue in the same terms.

Table 1. Stipulations and Agreements

Stipulation and Agreement	Not Contested	Contested (Sections I–XII)
Pensions Stipulation Company and Staff, Oct. 2, 2026	Pension and other post-employment benefit costs and trackers (lists no issues from the Amended Joint List)[23]	None

[20] See Staff Objection to LLPS Partial Stipulation and Agreement (Oct. 6, 2026) ("Staff LLPS Objection"); Public Counsel's Opposition to LLPS Settlement (Oct. 7, 2026) ("OPC LLPS Opposition"); MECG Response at ¶ 2. The Commission's rule does not provide for an objection made merely to preserve the ability to take positions in post-hearing briefs; it requires an objection to identify each provision objected to and give a reason. See 20 CSR 4240-2.115(2)(B) (Stipulations and Agreements). To the extent MECG advances in post-hearing briefing new arguments or positions not identified in its objection or supported by the record, such arguments would likely be improper under the rule, and the Company reserves all rights to object, move to strike, and otherwise respond.

[21] See LLPS Stipulation at ¶ 12; OPC LLPS Opposition at ¶¶ 8, 12; Staff LLPS Objection at ¶¶ 3–15; Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 19–20; Tr. Vol. 8 at 21:21–25 (Staff counsel).

[22] See Procedural Order at ¶ 3(D); Amended Joint List, Part I. The parties' statements of position are cited as Staff's Statement of Positions (Sep. 25, 2026) ("Staff Positions"), Public Counsel's Positions on Listed Issues (Sep. 25, 2026) ("OPC Positions"), MECG's Statement of Positions (Sep. 25, 2026) ("MECG Positions"), and Google LLC's Position Statement (Sep. 25, 2026) ("Google Positions").

[23] See Pensions Stipulation at ¶¶ 1–19.

Stipulation and Agreement	Not Contested	Contested (Sections I–XII)
Unopposed (may be treated as unanimous)		
Non-C&I Rate Design Stipulation Company and Staff, Oct. 2, 2026 Unopposed (may be treated as unanimous)	Issues 2.xiii–xiv, 28.A, and 29.C[24]	None
Partial Stipulation Company and Staff, Oct. 2, 2026 Opposed in part	Issues 2–4, 6–15, 17–24, 26–27, 30, and 34–35, in whole or in part, except the issues in the last row[25]	Issue 17.A, as to Iatan Unit 1 and La Cygne Unit 2 (MECG)[26]
Programs Stipulation Company, Staff, and Renew Missouri, Oct. 7, 2026 Opposed in part	Issues 16 and 38–41, except as noted	Issue 16.E (OPC)[27]
LLPS Stipulation Company and Google, Oct. 5, 2026 Opposed in part	Issue 23.A (31.8% SPP transmission percentage)[28]	Issues 3.A, 5, 22.B–D, 23.D, 25, and 37 (Staff, OPC, and potentially MECG)[29] On Issue 5, the Company's position matches Staff's.[30]

[24] See Non-C&I Rate Design Stipulation at ¶¶ 1–17.
[25] See Partial Stipulation at ¶¶ 1–11, 13-28.
[26] See MECG Response at ¶ 5.
[27] See Programs Stipulation at ¶ 18.
[28] See LLPS Stipulation at ¶ 12.
[29] See Staff LLPS Objection; OPC LLPS Opposition; MECG Response at ¶ 2.
[30] See LLPS Stipulation at ¶ 10.

Stipulation and Agreement	Not Contested	Contested (Sections I–XII)
Rate Design Settlement Company and MECG, Oct. 5, 2026 Opposed in part	Issues 29.A and 29.A.i (elimination of the Hours Use rate structure and the time-related periods)[31]	Issues 29.A.ii–vi, 29.B, 30.A, and 32 (Staff partially and OPC), including OPC's opposition to demand thresholds and 15-minute billing demand[32]
Issues not resolved by any stipulation	N/A	Issues 1, 15.A.i, 15.C, 18.B, 19.A–B, 20.B–C, 20.E–F, 20.H, 23.C (as to subaccounts 555006 and 447016), 31, 33, 36, and 42

Table 1A. What Each Agreement Accomplishes

Stipulation and Agreement	Outcome
Pensions Stipulation	The Company's pension cost has run below the amount built into rates, so the Company owes customers the difference. The stipulation puts that $55.1 million regulatory liability in rate base and returns it to customers over five years—about $11 million a year. It lowers the pension cost in rates from $28.5 million to $11.9 million (total company) and continues the pension and OPEB trackers the Commission has approved in the Company's rate cases since at least 2010.[33]
Non-C&I Rate Design Stipulation	The $12.00 customer charge and residential peak adjustment remain, and the rest of the residential bill takes an equal share of the increase. The agreement also settles the Economic Development Rider gross-up, standby minimum demand, parallel generation, and municipal lighting terms.[34]
Partial Stipulation	This is the main revenue requirement settlement with Staff. It settles most expense issues, two trackers (property tax and nuclear tax credits), depreciation rates, most FAC terms, and the billing estimation items. In exchange, Staff's revenue requirement rises by $46 million. The Company accepted Staff's billing determinants.[35]

[31] See Rate Design Settlement at 2.
[32] See OPC Rate Design Opposition at ¶¶ 1–4; Staff Rate Design Objection at ¶¶ 1–14.
[33] See Pensions Stipulation at ¶¶ 1, 8, 10–11; Ex. 41, Klote Direct at 18 (OPEB tracker established in Case No. ER-2010-0355), 23 (pension cost in current rates).
[34] See Non-C&I Rate Design Stipulation at ¶¶ 1–9.
[35] See Partial Stipulation at ¶¶ 1, 3, 10–12, 15, 22–27.

Stipulation and Agreement	Outcome
Programs Stipulation	Three customer assistance programs get more funds. The Economic Relief Program rises to $1,410,000 a year, Critical Medical Needs to $600,000, and income-eligible weatherization to $750,000, with Rehousing kept at $250,000. Shareholders pay half of every program dollar. The Company will also offer Green Button Connect data access by the end of 2028 and convene a battery storage stakeholder meeting by late 2027.[36]
LLPS Stipulation	The Company's first large load customer is already paying bills, and the stipulation credits $60 million a year of that revenue against what other customers pay. Large load customers stay in the FAC and pay the same fuel rate as everyone else, with a 90/10% sharing for their allocated portion that puts more fuel cost risk on the Company. If large load revenue pushes the Company's earnings more than 20 basis points above its authorized return, customers receive 65% of the excess, with any portion above 50% directed to low-income customers.[37]
Rate Design Settlement	The commercial and industrial rate structure is modernized when the new rates take effect. Demand thresholds change, billing demand moves to 15-minute intervals, and the Hours Use and all-electric rates end. The two classes that earn well above the system average return—large power service ("LPS") and large general service ("LGS")—take 94% of the system average increase, and residential customers take 100%. Staff and OPC object to several of its terms, but no party objects to eliminating the Hours Use structure.[38]

B. The Company's Revenue Requirement

At the June 30, 2026, true-up date, the Company's requested revenue requirement increase, including the rebasing of the FAC, was $162.6 million. The stipulations and agreements, principally with Staff, reduced that request by $73.7 million—more than 45%. As a part of those agreements, the Company accepted settled amounts in place of its own litigated positions on the issues they resolve. The Company now requests a revenue requirement increase of $88,902,805. Table 2 builds that figure from Staff's revenue requirement at true-up and summarizes the remaining differences between the Company and Staff's revenue requirement positions.

[36] See Programs Stipulation at ¶¶ 2, 5–7.
[37] See LLPS Stipulation at ¶¶ 3, 6–7, 9, 13 & Ex. D.
[38] See Rate Design Settlement at 1–2 & ¶ 2.

Table 2. Revenue Requirement Increase

	Company	**Staff**
Staff's revenue requirement at true-up, before LLPS revenue[39]	$71,723,677	$71,723,677
Partial Stipulation	46,000,000	46,000,000
Programs Stipulation[40]	313,056	313,056
Less LLPS revenue[41]	(60,000,000)	*** [redacted] ***
Contested issues: amount the Company's position adds (Staff's starting figure already reflects Staff's positions)		
Return on equity of 10.50% rather than 9.73%[42]	20,757,986	--
Construction work in progress for Mullin Creek No. 2[43]	5,691,286	--
Return on rate base Staff says is retired plant [44]	4,416,800	--
Revenue requirement increase[45]	**$88,902,805**	*** [redacted] ***

The RLJ noted that some of the six stipulations have been objected to in part, and asked how the Commission should address these, as well as how rates would be calculated from them. The Company requests that the Commission overrule the objections, approve the Agreements, and decide the contested issues as recommended by the Company. The Commission would then apply the Agreements and related issues in sequence, as Company witness Brad Lutz (Director, Regulatory Affairs) explained.[46]

Mechanically, there are four steps necessary to calculate rates from the adopted Agreements in this case. The first step is to calculate the revenue requirement (the total amount the

[39] See Staff Reconciliation at 2, line 137.
[40] See Programs Stipulation at ¶ 5.
[41] See LLPS Stipulation at ¶ 13; Staff Reconciliation at 2, line 139.
[42] See Staff Reconciliation at 1, line 7.
[43] Id. at 1.
[44] Id.
[45] The final amount will come from the joint reconciliation that the Company asks the Commission to order. See Conclusion.
[46] See Tr. Vol. 12 at 106:13–22 (Lutz).

Company's rates must collect). Table 2 above builds it from Staff's true-up figure and the amounts settled by the Agreements. The Commission's decisions on the contested issues complete the revenue requirement, and a joint reconciliation states the final amount thereof.

The second step is to apply the billing determinants, which are the demand and energy for which customers are billed. Rates are set so that, applied to those quantities, they collect the revenue requirement. In the Partial Stipulation, the Company accepted Staff's non-LLPS billing determinants for the current classes.[47]

The third step apportions the rate increase among the customer classes. The Rate Design Settlement assigns each class a percentage of the system average increase.[48] In answer to Chair Hahn, Mr. Lutz explained that the percentages apply to whatever revenue requirement the Commission sets. The small and medium general service classes absorb the last adjustments needed to make the class shares add up to the total.[49]

The fourth step sets the rates within each class so that each class collects its share. The Non-C&I Rate Design Stipulation governs residential rate design, and the Rate Design Settlement restructures the commercial and industrial rates, as Section X explains.[50] Mr. Lutz testified that the remaining adjustments are the type made in other rate cases, and that the Company's data will be ready once the Commission issues its order. The Company then files compliance tariff sheets.

The Company therefore respectfully requests that the Commission approve the Pensions Stipulation, the Non-C&I Rate Design Stipulation, the Partial Stipulation, and the Programs Stipulation. It also requests that the Commission adopt the uncontested terms of the Rate Design Settlement and the LLPS Stipulation and decide the remaining issues as Sections I through XII

[47] See Partial Stipulation at ¶¶ 2–3.
[48] See Rate Design Settlement at ¶ 2.
[49] See Rate Design Settlement at ¶ 2; Tr. Vol. 12 at 107:7–10, 115:1–9 (Lutz).
[50] See Non-C&I Rate Design Stipulation at ¶ 2; Rate Design Settlement at 1–2.

discuss.[51] Finally, it requests that the Commission direct a joint reconciliation of the revenue requirement that reflects those decisions. Approval of these stipulations substantially reduces the issues that the Commission must still resolve. Those remaining issues are discussed below.

C. Summary of Contested Issues for Commission Resolution

Each numbered section below provides a high-level summary of the remaining contested issues in the case and corresponds to a more fulsome section set out in the brief.

1. Large Load Power Service Issues (Section I)(pp. 24-61)

The Company respectfully requests that the Commission adopt the LLPS Stipulation. It passes the benefit of large load growth to the Company's other customers in three primary ways, among others. It credits $60 million of large load revenue against what those customers pay, keeps large load customers in the FAC on terms that favor other customers, and shares large load earnings with customers. This is a transitional case. Less than a year ago, the Commission approved Schedule LLPS as a package.[52] Through the Non-Unanimous Global Stipulation and Agreement (the "Global Stipulation") in Case No. EO-2025-0154, it reserved any modifications of LLPS cost allocation, rate design, and class cost of service for the first rate case in which a Schedule LLPS customer of 75 megawatts ("MW") or more is reflected in the test year.[53] No LLPS customer is in EMM's test year—the twelve months ending June 30, 2025—because the Schedule LLPS tariff

[51] Where objections reach only some provisions of a stipulation, the Commission has adopted the provisions to which no party objected. See Report & Order at 35–36, In re: Evergy Natural Gas Generation CCN Application, No. EA-2025-0075 (July 31, 2025) (adopting the unopposed conditions of an objected stipulation); Report & Order at 48, 58, In re: Empire District Electric Co. d/b/a Liberty Rate Increase, No. ER-2024-0261 (Jan. 14, 2026) ("Liberty Order") (approving the 27 provisions of an objected stipulation to which no party objected and addressing only the objected provisions). In the Liberty Order, the Commission found that the unobjected provisions were "reasonable resolutions of the issues that each addresses and will produce just and reasonable rates." Liberty Order at 58.

[52] See Report & Order at 46, In re: Evergy Large Load Customer Tariff Filing, No. EO-2025-0154 (Nov. 13, 2025) ("Large Load Order"), *rehearing denied*, Order Denying Application for Rehearing, No. EO-2025-0154 (Jan. 7, 2026).

[53] See Non-Unanimous Global Stipulation and Agreement at ¶ 14, No. EO-2025-0154 (Sep. 25, 2025).

took effect on March 9, 2026.[54] The Commission should preserve the framework it approved until then, rather than relitigate it on estimates.

The $60 million credit is the revenue of the Company's first LLPS customer ("Customer A") at the June 30, 2026, true-up, based on its known and measurable billing determinants (Issue 3.A). Because none of the Company's revenue requirement is caused by LLPS load, every dollar of that revenue lowers what other customers pay from the day the new rates take effect. However, Staff's competing figure is not known and measurable, because it multiplies a contract capacity Customer A had not reached by an estimated load factor. Additionally, the LLPS Stipulation's only tariff change settles on a single reading of the minimum bill, which raises LLPS bills during the ramp.

The Company serves Schedule LLPS customers from the same system as every other customer. It sells its generation into the SPP market and buys the energy for all of its load from that market, so sales and purchases largely net out. What remains is the fuel cost of running the Company's own generators, which serve every customer. LLPS customers should therefore remain in EMM's FAC, as Schedule LLPS was designed (Issue 25). The LLPS Stipulation's FAC terms favor other customers in two ways. First, fuel cost swings related to the LLPS allocated portion are shared 90/10% rather than 95/5%. The Company therefore absorbs more of any increase and the single fuel adjustment rate every customer pays is lower. Second, the base factor is built from Staff's own fuel costs and leaves LLPS customers' fuel out of it, so nothing is recovered twice. Staff's own witness agreed that the energy rate LLPS customers pay and the cost of the energy to serve them come out about even.

[54] See Order Approving Tariffs at 2, In re: Evergy Large Load Customer Tariff Filing, No. EO-2025-0154 (Feb. 25, 2026).

Finally, the LLPS Stipulation shares large load earnings with customers through the Earnings Review Surveillance mechanism ("ERS") (Issue 37.A). An authorized return is an opportunity to earn, and large load growth gives the Company a realistic chance to earn it. The ERS keeps that opportunity in place and provides a customer sharing mechanism as well. Sharing occurs when the Company's earned ROE exceeds the ROE authorized in this case by more than 20 basis points and LLPS base rate revenue exceeds the $60 million in rates. Customers then receive 65% of the earnings above that threshold through a future rate case, with any share above 50% directed to low-income customers. That way, sharing tracks large load growth rather than weather or expense variation. The Commission approved a mechanism of substantially the same design for Ameren Missouri last year, and the Large Load Order contemplated an earnings-sharing mechanism in a future rate case after LLPS customers begin receiving service.[55]

2. Non-LLPS FAC Issues (Section II)(pp. 61-68)

The Company respectfully requests that the Commission adopt three FAC terms addressed by the LLPS Stipulation: the base factor, the inclusion of long-term capacity purchases and sales, and two new subaccounts to record them. The Partial Stipulation settles the other FAC issues for non-LLPS customers, including the 95%/5% sharing mechanism, and no party objected to those terms.

First, the base factor of $0.01742 per kilowatt-hour ("kWh"), the fuel cost built into base rates, is built from Staff's own numbers (Issue 22.C). It matches Staff's own revenue requirement,

[55] See Amended Non-Unanimous Global Stipulation and Agreement at ¶ 46, No. ET-2025-0184 (Nov. 20, 2025), approved, Order Regarding Ameren Missouri's Request for Approval of a Large Load Rate Plan and Associated Variance at 4, 6–7, In re: Application of Union Electric Company d/b/a Ameren Missouri for Approval of New Modified Tariffs for Service to Large Load Customers, No. ET-2025-0184 (Nov. 24, 2025); Large Load Order at 43 (Finding of Fact 102).

which Staff's own illustrations say a base factor must do. Staff's own numbers also show that including the Company's long-term capacity sales lowers it by $0.00104 per kWh.

Second, the FAC should include long-term capacity purchases and sales (Issues 23.C and 23.D). It already covers capacity purchases and sales of one year or less. Section 386.266.1[56] reaches purchased-power costs, and long-term capacity purchases are purchased-power costs.

3. Cost of Capital (Section III)(pp. 68-86)

The Company respectfully requests that the Commission authorize a 10.50% ROE on the Company's actual capital structure of 52.19% equity (Issues 1.A and 1.C). Staff and OPC recommend 9.73% and 9.25%, respectively, on analyses that have not changed since December. However, between December 31, 2025, and the June 30, 2026, true-up the 30-year Treasury yield rose 7 basis points and the 10-year Treasury yield rose 26 basis points. Since the true-up, interest rates and the costs of raising capital have continued to rise. Between June 30 and October 30, 2026, the 30-year Treasury yield rose 40 basis points and the 10-year Treasury yield rose 50 basis points.[57]

The capital structure should be the Company's actual per-book structure at true-up: 52.19% common equity and 47.81% long-term debt. Staff recommends the same. OPC would instead impute an adjusted version of Evergy, Inc.'s consolidated structure, 45% equity and 55% debt. The Company issues its own debt, carries no parent guarantee, and holds stand-alone credit ratings stronger than its parent's. The cost of debt, 4.54%, is not in dispute.

[56] See Section 386.266.1 (Rate schedules for interim energy charges or periodic rate adjustment).
[57] See Bd. of Governors of the Fed. Reserve Sys., Statistical Release H.15, Selected Interest Rates, Market Yield on U.S. Treasury Securities at 10-Year and 30-Year Constant Maturity (daily) (10-year: 4.18% on Dec. 31, 2025, 4.44% on June 30, 2026, and 4.94% on Oct. 30, 2026; 30-year: 4.84%, 4.91%, and 5.31% on the same dates). The Company requests that the Commission take official notice of these yields under Section 536.070(6). Section III collects the authorities.

Company witness Ann Bulkley (Principal at The Brattle Group) recommends 10.50% at the low end of a 10.25% to 11.25% range. The Company carries business risk above its peers: a large capital program, partial and delayed recovery under PISA, nuclear operations, and an FAC that leaves 5% of fuel cost variance with the Company. Indeed, utilities with nuclear operations have been authorized an average ROE 37 basis points above the industry average. The Commission should therefore authorize an ROE of 10.50%.

Staff witness Dr. Seoung Joun Won recommends 9.73%, but he rests that figure on a single bond yield risk premium analysis. His mean discounted cash flow result was 8.18% and the average of his mean DCF and capital asset pricing model results was 8.67%. These results are below any ROE authorized for a vertically integrated electric utility since 1980. OPC witness David Murray recommends 9.25%, a figure none of his own studies supports. Dr. Won's analysis should be given limited weight given his narrow analysis. However, as considered, his midpoint should be updated to reflect changes in market conditions since December 2025, and Mr. Murray's unsupported recommendation should be disregarded.

4. Income Taxes (Section IV)(pp. 86-91)

The Company respectfully requests that the Commission reject OPC's two income tax adjustments, which Staff also opposes (Issues 15.A.i and 15.C). Staff's reconciliation values them at $5,437,280 and $2,941,318 of revenue requirement. The Partial Stipulation resolves the other income tax sub-issues between the Company and Staff, and OPC does not oppose it. First, OPC would reduce income tax expense by a levelized amount of the tax losses recorded when an asset retires early. However, customers have already received the tax benefit on the losses through accumulated deferred income taxes, which reduce rate base. OPC's adjustment to include the tax

benefits again as an offset to income tax expense would inappropriately include the tax benefits on losses twice.

Second, OPC would remove from rate base the deficient deferred income taxes created by the federal and Missouri income tax rate reductions on the Company's net operating losses. However, the Commission has already set the treatment of that balance. The Company's 2018 rate case set the amortization of the federal amount, and the stipulation the Commission approved in the 2022 rate case set a four-year amortization of the Missouri amount. As Staff testified, OPC does not explain why that treatment should change now.

5. Fuel and Purchased Power (Section V)(pp. 91-92)

The Commission should adopt Staff's fuel and purchased power costs, which the LLPS Stipulation adopts and no other party contests (Issue 5). That includes Staff's total variable fuel and purchased power cost, as agreed in the LLPS Stipulation, with the Missouri jurisdictional amount as Staff's reconciliation states. It also includes Staff's fuel prices, normalized market prices, and historical transmission congestion rights amount.

6. MEEIA Margin Rates (Section VI)(pp. 93-96)

The Commission should approve the Company's method for calculating the net margin rates used in its Demand Side Investment Mechanism Rider under the Missouri Energy Efficiency Investment Act ("MEEIA") (Issue 42).[58] Staff does not oppose the Company's method, and the Commission should approve it. Staff also states that the net margin rates should be recalculated on the final rates in this case, which the Company's tariff already requires.

[58] See Section 393.1075 (Missouri Energy Efficiency Investment Act).

7. PISA (Section VII)(pp. 96-97)

The Company respectfully requests that the Commission include in rate base the PISA deferral balance in Exhibit B to the Partial Stipulation (Issue 18.B). Section 393.1400[59] requires that balance be included in rate base without offset or adjustment, except for a prudence disallowance the Commission has ordered. OPC's only objection is to remove the distribution and transmission projects it asks the Commission to disallow. Those disallowances should be rejected for the reasons summarized in Subsection C.8, below. In short, OPC identifies no decision that was unreasonable when it was made, and its own analysis shows reliability improved on the laterals it would disallow. Its value-exceeds-cost test did not exist when the investments were made, and the Commission has never adopted it. If the Commission were to order a disallowance (which the Company's evidence demonstrates it should not), Partial Stipulation ¶ 7 provides for an adjustment removing the related PISA deferral, computed for the specific projects from their in-service dates and depreciation rates.

8. Rate Base and Asset Management (Section VIII)(pp. 97-119)

The Company respectfully requests that the Commission: (1) include the CWIP for Mullin Creek No. 2 in rate base, (2) reject Staff's retired plant adjustment, and (3) reject OPC's transmission and distribution disallowances. The investments at issue here keep the Company's service reliable, from a new generating unit to the replacement of aging poles, lines, and transformers.

[59] See Section 393.1400 (Deferral of depreciation to regulatory asset — definitions — return for qualifying electric plant recorded to plant-in-service on utility's books — regulatory asset balances — requirements — grid modernization projects — expiration date.).

Construction Work in Progress for Mullin Creek No. 2 (Issues 20.B and 20.E)(pp. 98-102, 107-109)

Mullin Creek No. 2 is a natural gas generating unit that the Company is developing to serve all of its customers. CWIP is the cost of a plant while it is still under construction. Section 393.135.2[60] now permits CWIP to be included in rate base, and the Company's CWIP balance for the unit is $64,389,129. The statute directs the Commission to determine the amount of CWIP that may be included in rate base in the plant's certificate of convenience and necessity ("CCN") case, No. EA-2026-0154, which is pending. Section VIII explains three ways the Commission can satisfy that statute before rates take effect. The Company's preference is that the Commission decide the CCN case first and then include the CWIP in rate base here. The CCN application requests a decision by December 23, 2026, which is before the January 6, 2027, operation-of-law date in this case.

OPC would include no CWIP at all in EMM's revenue requirement. OPC argues that turbine prepayments for the generation asset are not construction costs and that CWIP should be included only if the plant's cost is assigned to large load customers. However, turbine prepayments are recoverable construction project expenditures within the statute, and that statute does not require LLPS customers to agree to bear the cost of a system resource. Mullin Creek No. 2 serves all customers. Its CWIP revenue requirement is part of the increase that the Rate Design Settlement divides among all classes. Schedule LLPS customers will pay their share as a subclass of LPS, consistent with Section 393.130.7, as Section X explains. Additionally, the $60 million of LLPS revenue in the LLPS Stipulation reduces the increase every class pays, CWIP included. A Schedule

[60] See Section 393.135 (Charges based on nonoperational property of electrical corporation prohibited — exceptions, expiration.).

LLPS cost allocation will come in the first rate case with a 75 MW LLPS customer in the test year, as the Company committed in the Global Stipulation.

Moreover, CWIP should earn the overall rate of return the Commission sets in this case. Section 393.135.2 provides for no separate return on CWIP, and Staff agrees that the overall rate of return applies. OPC would instead apply a 5.08% rate of return. OPC's own witness acknowledged that an asset-specific return is not a typical ratemaking step, and he could not name a commission that has approved one.

Staff's Retired Plant Adjustment (Issue 20.C)(pp. 97-107)

The Commission should reject Staff's retired plant adjustment. Staff would stop applying the rate of return to approximately $50 million of rate base that it says represents plant retired since the last rate case, while continuing to depreciate the same assets. Staff's own witness, Matthew Young, acknowledged that an adjustment of this kind may be "new." Staff's "new" approach should be fully disregarded. A retirement under mass asset accounting leaves net rate base unchanged. Retirement experience is addressed through depreciation rates that Staff did not change. And Staff's PISA theory does not explain why any asset was retired.

OPC's Transmission and Distribution Disallowances (Issues 19.A–B, 20.F, and 20.H)(pp. 97-104)

The Commission should reject OPC's disallowances of $87.8 million of transmission investment and $42.6 million of distribution investment under the prudence standard. Staff recommends no distribution disallowance and takes no position on the transmission disallowances. A utility's costs are presumed to be prudent, and its decisions are judged by what was reasonable when they were made, without hindsight. Any disallowance must be supported by findings of both imprudence and harm to customers. OPC identifies no EMM decision that was unreasonable when

it was made, and its own witness, who asserted that "several" projects produced no customer benefit, conceded that his testimony identifies none. OPC's claim of harm rests on a test that the value of each replacement must exceed its cost. No such test existed when the investments were made, and the Commission has never adopted one. The Commission should decline to create that standard after the fact and should reject OPC's proposed disallowances. For the $14.7 million of transmission facilities serving the Panasonic delivery point, OPC's witness performed no prudence review of any identified project and could not define base plan funding. He also described his disallowance percentage as an estimate that he agreed could be adjusted with more information.

OPC's own analysis of the Lateral Improvement Program shows reliability improved on the laterals rebuilt in 2022, yet OPC would disallow the entire $21.8 million as though the program delivered nothing.

The Company has systematically and prudently invested in the reliability of its system. No analysis has been presented demonstrating imprudence on the part of the Company in making the investments and the Company's management and overview of its system investments is comprehensive and representative of the management oversight this Commission should expect.

9. Income-Eligible Programs and Energy Burden Analysis (Section IX)(pp. 119-127)

The Company respectfully requests that the Commission approve the Programs Stipulation and leave OPC's proposed customer charge waiver program to the Commission's Affordability Workshop, Case No. OW-2026-0085 (Issue 16.E). Customers who struggle to pay their bills need help now, and the Programs Stipulation delivers more of it. The Company directed additional dollars to its Economic Relief Program ("ERP"), which reaches households up to 200% of the federal poverty level, above the eligibility tests of the Low-Income Home Energy Assistance

Program ("LIHEAP"). OPC's one objection is that the Commission should create, *in this case*, a program waiving the customer charge for low-income customers, with a $6 million annual budget and no restrictions. This request is not appropriate for this rate case and not ripe for decision. Rather, such a program could be developed in the Commission's Affordability Workshop. Section 393.1680[61] commits any such rate to a rulemaking and third-party eligibility verification. Neither of these prerequisites has occurred.

10. Rates and Revenue Responsibility (Section X)(pp. 127-164)

The Company respectfully requests that the Commission adopt the Rate Design Settlement (Issues 29, 30, and 32) and reject Staff's proposed Critical Peak Rate ("CPR") (Issue 33.A). The settlement restructures the commercial and industrial rates and divides the increase among the customer classes. Staff objects to parts of it, and OPC opposes the shifts in revenue responsibility among classes.

First, the restructured rates should take effect with the rate increase (Issue 29.A.vi). Staff does not object to the demand thresholds, the 15-minute billing demand, or the elimination of the Hours Use and all-electric rates. It would nonetheless delay the restructured rates to November 2027 for a customer migration study and customer education. Staff's witness conceded that no one claims the determinants are missing, and she identified no case in which a rate change was delayed for a Staff study. Delay would perpetuate for another year a structure that no party defends.

Second, the apportionment of the increase follows the cost studies (Issue 32.A). LPS and LGS earn well above the system average return, and the Rate Design Settlement moves them toward cost at 94% of the system average increase. Staff, which recommends an equal percentage

[61] See Section 393.1680 (Special alternative residential customer rate, when.).

increase to every class, prepared no class cost of service study of its own, conceding that it failed to assign resources to such an effort.

OPC would also assign all of the CWIP for Mullin Creek No. 2 to Schedule LLPS customers (Issue 32.D). As Subsection C.8 above explains, the plant is a system resource, and Schedule LLPS customers will pay their share of its CWIP as a subclass of LPS.

Finally, Staff's CPR should not be ordered. The CPR is a per-kWh surcharge on usage during event days. An event occurs when the day-ahead market prices exceed $100 in every hour of one day and reach $100 in every hour of the next. The CPR would be mandatory for every customer not specifically exempted, including hospitals. Moreover, Staff has not quantified any benefit or revenue, Staff did not work with the Company or any party on design and has not advanced an implementable tariff, only a broad concept, and Staff's witness could not recall a critical peak rate ever coming before the Commission.

11. Trackers (Section XI)(pp. 165-169)

The Company respectfully requests that the Commission approve a tracker for critical infrastructure protection ("CIP") and cyber security costs above the test-year level (Issue 36.B). That level—$4,491,745 on a total-company basis—is in the revenue requirement, and no party disputes it. Staff and OPC oppose the tracker as unnecessary because past spending has been stable. However, as Company witness Charles King discusses, a stable history does not forecast costs driven by new federal mandates, emerging threats, and third-party events like the CrowdStrike outage. The tracker reconciles collections to actual prudently incurred costs, excludes internal labor, and ends with the first rate case filed on or after January 1, 2031.

12. Depreciation (Section XII)(pp. 169-172)

The Company respectfully requests that the Commission adopt the depreciation rates in corrected Exhibit C to the Partial Stipulation, which are based on Staff's true-up model (Issue 17.A). MECG's only objection would move the probable retirement dates of Iatan Unit 1, La Cygne Unit 2, and La Cygne Common from 2040 to 2045. Mr. Andrews estimates that change would reduce depreciation expense by about $7.3 million a year. However, Staff and the Company both use 2040, and Staff requests that MECG's dates be rejected. Company witness John Spanos fully supports the depreciable lives in his depreciation study and testimony presented. Moreover, MECG's witness took his dates from the final planning year of the Company's 2026 integrated resource plan, which lists no retirement date for either unit.

D. Requested Relief

Based on the substantial evidence in the record, the Company respectfully requests that the Commission approve the Company's general rate increase, as modified by the stipulations and agreements, as supported by the preponderance of evidence in this case for the issues to be decided by the Commission.

ARGUMENT AS TO CONTESTED ISSUES[62]

I. LARGE LOAD POWER SERVICE ISSUES

3. Other Revenues (EMM: Gunn, Jaynes; Staff: Lange, Luebbert (also adopting Rucker); Google: Berry; MECG: Meyer; OPC: Nelson)

The Company respectfully requests that the Commission approve the LLPS Stipulation signed by the Company and Google. The stipulation is consistent with the Commission's Report

[62] The issue statements in this Brief are taken from the Amended Joint List, which states: "Each party does not necessarily agree with the wording of some issues or inclusion of all of the issues set out herein. The inclusion of an issue and a party's position thereon in the list below does not mean all parties agree with such issue's characterization, that such issue identified is actually in dispute, and/or that a Commission decision on such issue is proper or necessary in this case." Amended Joint List at 2 n.2.

and Order and Non-Unanimous Global Stipulation and Agreement (the "Global Stipulation") in Case No. EO-2025-0154. On November 13, 2025, the Commission approved the Company's Large Load Rate Plan and Schedule LLPS, as modified by the Global Stipulation. It did so because the plan establishes a transparent framework consistent with emerging national trends for large load customers, with clear eligibility, pricing, commitments, safeguards, and optional clean-energy riders. That framework enables data centers and other large loads to meet sustainability goals without shifting costs.[63]

In the Commission-approved Global Stipulation, the parties agreed that no party will be restricted in the positions it may advance on cost allocation, rate design, or class cost of service methodologies in one future case. That case is the first general rate case in which at least one Schedule LLPS customer of 75 MW or greater is reflected in the test year. That customer must also be captured in the class cost of service ("CCOS") study determinants.[64]

No Schedule LLPS customer was included in Evergy Missouri Metro's test year, *i.e.*, the 12 months ending June 30, 2025, updated through a true-up period ending June 30, 2026. This general rate proceeding is therefore a transitional case.[65] Accordingly, the record in this proceeding does not contain sufficient evidence to support drastic changes to cost allocation, rate design, or class cost of service methodologies, particularly as they relate to large load customers. The Commission should decline to adopt such measures here. Instead, those issues are more appropriately addressed in a future general rate case in which Schedule LLPS customers are reflected in the test year. That approach is consistent with the framework the parties have already

[63] See Ex. 20, Gladhill Direct at 8; Report & Order at 16, 25, 46, In re Evergy Large Load Customer Tariff Filing, No. EO-2025-0154 (Nov. 13, 2025) ("Large Load Order"), rehearing denied, Order Denying App. For Rehearing, No. EO-2025-0154 (Jan. 7, 2026); Non-Unanimous Global Stipulation and Agreement, No. EO-2025-0154 (Sep. 25, 2025).
[64] See Global Stipulation at 8; LLPS Stipulation at ¶ 2.
[65] See LLPS Stipulation at ¶ 1; Tr. Vol. 6 at 40:23–41:4 (Google opening statement).

agreed to in the Global Stipulation. Indeed, Evergy Missouri Metro will fulfill its obligation to "evaluate the costs and impacts of any Schedule LLPS customers added to the system and propose a cost allocation and rate design proposal designed to ensure the alignment of costs and cost causation" in that rate case.[66] The terms for this transitional case are established in the LLPS Stipulation, which was signed by Google and not opposed by Velvet Tech.

Therefore, the Commission should approve the LLPS Stipulation, which would in turn resolve the large load power service issues in Section I that it addresses.[67]

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?

The Commission should approve the LLPS Stipulation without modification and include $60 million of LLPS revenue in Evergy Missouri Metro's revenue requirement.[68]

No Schedule LLPS customer of 75 MW or more is reflected in the test year. Evergy Missouri Metro therefore used the annualized value of the known and measurable billing determinants of its Schedule LLPS customer at true-up, June 30, 2026.[69] This treatment of LLPS revenue is consistent with the Commission's Report and Order in Case No. EO-2025-0154, the Large Load Order. There, the Commission stated that "[a]ny treatment of revenues from LLPS customers will be determined in a future rate case where those revenues would be known and measurable."[70]

For Customer A, known and measurable information as of June 2026 was used to annualize 12 months of activity at the June 2026 level.[71] Company witness Darrin Ives (Senior Vice President – Regulatory and Government Affairs) testified to the same derivation. The $60 million

[66] See Global Stipulation at 8; LLPS Stipulation at ¶ 2.
[67] See LLPS Stipulation at 2-4.
[68] See LLPS Stipulation at ¶ 13.
[69] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 27.
[70] See Large Load Order at 44.
[71] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 27.

was derived by examining the Schedule LLPS customer's billing determinants as of June 30, 2026, at an annualized amount.[72] Those billing determinants are in the record. The LLPS Stipulation reflects 562,186,656 kWh with the $60 million of LLPS revenue, and in the Partial Stipulation the Company accepted Staff's own non-LLPS billing determinants.[73] Staff's claim that there are no billing determinants in this case is therefore incorrect, as discussed under Issue 29.A.iv.[74]

As such, the $60 million revenue requirement is not a negotiated abstraction between the Company and Google. Rather, the parties were "similarly situated" using known and measurable billing determinants at true-up, with one caveat. Google's witness Dr. Carolyn Berry (Partner, Bates White Economic Consulting) "appl[ied] the energy charges on top of the minimum demand" of 80% of contract capacity, which is what the LLPS Stipulation agrees to.[75]

This is the standard process for any retail customer not included in the test year or increasing its load, and Staff agrees. Staff witness Sarah Lange testified that a new or growing customer without 12 months of history is annualized on the information available at the stage of testimony.[76]

Additionally, approving the $60 million revenue requirement in the LLPS Stipulation is beneficial to all customers, as Google agrees.[77] As discussed by Company witness Kevin Gunn (Vice President – Regulatory and Government Affairs) and Ms. Lange, none of the costs reflected in the Company's revenue requirement are caused by Schedule LLPS customers.[78] Because no

[72] See Tr. Vol. 12 at 56:19–57:2 (Ives).
[73] See LLPS Stipulation at ¶ 13; Partial Stipulation at ¶¶ 2–3.
[74] See Tr. Vol. 6 at 31:2–10 (Staff counsel); Tr. Vol. 12 at 25:21–24 (Chair Hahn), 175:12–19 (Sarah Lange).
[75] See Tr. Vol. 12 at 57:16–22 (Ives).
[76] See Tr. Vol. 7 at 137:8–138:2 (Sarah Lange). Volume 7 of the official transcript (EFIS Item 344) does not print page or line numbers. Citations to it give the page of the filed document and the line counted from the top of that page.
[77] See Tr. Vol. 12 at 47:2–10 (Google counsel) (statement of a party's position).
[78] See Ex. 21, Gunn Direct at 17; Ex. 22, Gunn Rebuttal at 2, 5; Tr. Vol. 7 at 110:25–111:4 (Sarah Lange) ("[T]he large load customer A is not increasing the revenue requirement in this case. Is that right?" "On a net basis, I think that's true.").

new generation or transmission facilities are needed to serve Customer A in rates in this case, "all non-energy revenue from Customer A should fully offset the Missouri jurisdictional cost of service."[79] Given this, and consistent with the LLPS Stipulation's earnings sharing mechanism discussed under Issue 37, the "amount of net revenues in discussion, all else being equal, would cause other ratepayers' rates to be lower than they otherwise would be."[80] That revenue also bears on Chair Hahn's question of how the CWIP included in rates in this case is allocated among the classes.[81] The $60 million of LLPS revenue reduces the increase every class pays, including the $5.7 million revenue requirement for CWIP for Mullin Creek No. 2, which is the offset the Commission anticipated in the Large Load Order, as discussed under Issue 32.D.[82]

Staff's Revenue Requirement Is Not Known and Measurable

In direct contrast, Staff's proposed LLPS revenue requirement is improperly based on a contract capacity level Customer A had not reached as of the June 30, 2026, true-up, multiplied by a midpoint of a range of assumed load factors.[83]

Staff calculates Customer A's revenue "based on the contract demand level in place as of June 2026," which "is the revenue level Staff uses for its true-up calculations," excluding energy revenue.[84] As Ms. Lange explains, that revenue is "calculated using the Year 1 contract demand … for each of the 12 months."[85] That is a projection of what Customer A might pay over the following year under its contract, not a measurement of what Customer A paid at true-up, which is known and measurable. Indeed, Staff deliberately made the decision to evaluate its LLPS

[79] See Ex. 170, Sarah Lange True-Up Rebuttal at 6.
[80] See Tr. Vol. 7 at 111:16–19 (Sarah Lange).
[81] See Tr. Vol. 9 at 97:25–98:16 (Gunn).
[82] See Large Load Order at 43; LLPS Stipulation at ¶ 13; Staff Reconciliation at 1, line 35.
[83] See Tr. Vol. 7 at 129:15–130:3, 131:8–132:11 (Sarah Lange).
[84] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 39; Ex. 170, Sarah Lange True-Up Rebuttal at 6; Vol. 7 at 113:3–7 (Sarah Lange) (Ms. Lange testified that she was "not aware of anything in the stipulation that indicates how that number was calculated.").
[85] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 39.

revenue requirement based on Customer A's contracted capacity despite attaching Customer A's bills to Ms. Lange's true-up direct testimony as Highly Confidential Schedule SLKL-td1.[86] In doing so, Staff indiscriminately projected Schedule LLPS customer revenues when compared to other retail customers. Staff incorporated Customer B, a Large Power Service customer, "at a normalized and annualized level" and "to the same extent as any other retail customer,"[87] but calculated Schedule LLPS customers using their contracted demand and an assumed load factor.[88]

Additionally, because Staff started from a different premise, its objection identifies no error in the signatories' calculation.[89] As Mr. Ives testified, Staff instead used "a contract capacity value that goes out beyond the . . . true up date in this case," paired with a projected load factor. The load factor is, by Staff's own description, "EMM's representation of expected load factor"[90]—a planning assumption Mr. Ives called "really just an estimate." The capacity value is "a pretty far forward . . . capacity value without consideration of where the actual loads were . . . at the time of the true up."[91] Multiplying one estimate by another does not produce a known and measurable revenue adjustment.

Staff's own testimony confirms those forecasts cannot be relied on. Staff testified that modeling Customer A's hourly energy use requires assumptions for which "[t]here is not sufficient information . . . at this time,"[92] and left Customer A out of its true-up fuel run because "the actual hours of Customer A load cannot be reasonably normalized at this time."[93] Staff cannot have it both ways. If Customer A's load is too uncertain to normalize for fuel costs experienced by EMM,

[86] See id. at 34.
[87] See id.
[88] Id.
[89] See Tr. Vol. 12 at 57:23–58:5 (Ives).
[90] See Staff LLPS Objection at ¶ 14.
[91] See Tr. Vol. 12 at 101:6–12 (Ives).
[92] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 22.
[93] Id. at 43.

it is too uncertain to project for revenue. Nor is the contract capacity itself fixed. Company witness Brad Lutz (Director, Regulatory Affairs) testified that EMM's Schedule LLPS allows "all of those numbers to be revised," and allowed that "at its core" this "could be equated with uncertainty."[94] And large load customers' views on ramp, growth, and steady-state load "move fairly frequently."[95] Therefore, a contract value that may be revised before rates take effect is not known and measurable.

Even on its own terms, Staff's calculation is incomplete. Staff's principal criticism of the LLPS Stipulation is that the Company's calculation of Customer A revenues is "understated due to the minimum bill calculation issues."[96] However, the LLPS Stipulation resolves that concern by adopting the minimum-demand reading Staff describes. It is Staff's competing calculation that omits it: Staff's Attachment B to its Objection to LLPS Partial Stipulation and Agreement does not illustrate an 80% minimum demand, and Ms. Lange conceded that Staff "probably should have thrown that in, too."[97]

The "expected load factor" came from a range the Company gave in response to a Staff data request, and Staff tested it against nothing the signatories could have provided.[98] Ms. Lange conceded that Staff "had to present it for true-up as a true-up plug, just in order to kind of make things make sense."[99] A placeholder built from a forecast load factor and a revisable contract capacity that Customer A had not reached at true-up is not known and measurable.

[94] See Tr. Vol. 12 at 148:10–16 (Lutz).
[95] See Tr. Vol. 12 at 89:11–25 (Ives).
[96] See Staff LLPS Objection at ¶ 6; Ex. 170, Sarah Lange True-Up Rebuttal at 4.
[97] See Tr. Vol. 7 at 135:19–136:5 (Sarah Lange); Ex. 178.
[98] See Ex. 111, Mastrogiannis Direct at 7; Tr. Vol. 7 at 90:7–91:1 (Sarah Lange), 146:25–147:6 (Luebbert).
[99] See id. at 109:15–20 (Sarah Lange).

OPC's and MECG's Revenue Requirement Is Not Known and Measurable

OPC requests the Commission to raise the LLPS revenue requirement adjustment to $117 million a year.[100] OPC witness Ron Nelson calculated the adjustment from estimates rather than recorded revenue.[101] When asked whether any recorded annual revenue exists at that level, he answered: "Just the estimates provided by the Company."[102] However, as discussed by Mr. Jaynes, there is no calculation or supporting analysis for OPC's projected annual revenues.[103] Thus, OPC's revenue requirement adjustment is not known and measurable.

MECG filed in support of including at least $25 million.[104] At hearing, Chair Hahn asked MECG witness Greg Meyer whether MECG would still track revenue above the Stipulation's base amount, and he answered yes, noting that "it's now grown to 60 million in the stip."[105] On cross he testified that he "would probably track it against the 60 million that you . . . stipulated to at this point."[106] MECG's witness thus accepts the Stipulation's $60 million as the base revenue level.

Therefore, the Commission should approve the LLPS Stipulation's known and measurable $60 million revenue requirement because it is consistent with the Commission's Report and Order in Case No. EO-2025-0154 and beneficial to all customers.

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

The Commission should approve no revenue adjustment for expected future revenues from Schedule LLPS customers beyond the $60 million in the LLPS Stipulation. That figure is stated at the Schedule LLPS rates in effect at the end of the true-up.[107] Requiring an expected future

[100] See Ex. 209, Nelson Surrebuttal at 2, 9.
[101] See Ex. 208, Nelson Direct at 19, 25.
[102] See Tr. Vol. 7 at 177:22–25 (Nelson).
[103] See Ex. 37(C)/38(P), Jaynes True-Up Rebuttal at 2.
[104] See Ex. 301, Meyer Direct at 9; Ex. 304, Meyer Surrebuttal at 5.
[105] See Tr. Vol. 7 at 169:2–25 (Meyer)
[106] See id. at 171:13–19 (Meyer).
[107] See LLPS Stipulation at ¶ 13; Tr. Vol. 12 at 82:5–10 (Ives).

revenues adjustment based on insufficient data in the cost of service model would be invalid pursuant to the Global Stipulation in Case No. EO-2025-0154, based on pure estimation, and discriminatory to LLPS customers. Staff instead grosses up Customer A revenue for the rate increase it anticipates in this case,[108] which the Commission should not adopt.

Under the Rate Design Settlement, Schedule LLPS is a subclass of the Large Power Service class, and its rates change with that class.[109] Grossing up LLPS revenue for the increase would therefore apply the increase twice. As Mr. Jaynes explained, factoring up LLPS revenue "improperly blends revenue requirement and rate design which risks creating confusion in the case record."[110]

Staff's gross-up also treats one customer differently from all others. Ms. Lange agreed that Staff does not consider a specific level of rate increase in this case to be a known and measurable change.[111] She also agreed that Staff did not gross up Customer B or the Large Power Service class for the proposed increase.[112] Nor does Staff gross-up the residential or other classes until compliance tariffs.[113] Ms. Lange described the gross-up as a matter of presentation and acknowledged that "this was a confusing presentation."[114] The Commission should state the LLPS revenue adjustment at the rates in effect at the true-up and apply any increase once, in rate design.

Therefore, the Commission should approve the revenue adjustment in the LLPS Stipulation.

[108] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 33–34, 42.
[109] See Rate Design Settlement at ¶ 2.
[110] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 23.
[111] See Tr. Vol. 7 at 117:10–13 (Sarah Lange).
[112] See id.at 117:14–23 (Sarah Lange).
[113] See id. at 118:14–17 (Sarah Lange).
[114] See id. at 120:1–3 (Sarah Lange).

31. Large Load Power Service Tariff and Reporting (EMM: Gunn, Ives, Lutz, Nunn, Meitner; Staff: Lange, Eubanks; Google: Berry; OPC: Marke)

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

The only change to EMM's Schedule LLPS should be to the Minimum Monthly Bill, as discussed in the LLPS Stipulation.[115]

The LLPS Stipulation revises EMM's Schedule LLPS billing demand for each Minimum Demand of 80% of Contract Capacity in monthly billing.[116] The clarification is needed because two provisions of the existing Schedule LLPS bear on the minimum bill. Currently, the tariff applies a Minimum Monthly Bill at the higher of measured demand or 80% of annual Contract Capacity.[117]

It also contains a separate Minimum Monthly Bill provision, which sums the charges listed in the tariff at the Minimum Demand.[118] Depending on how those two terms are read, the existing tariff supports either result.[119] The LLPS Stipulation resolves this inconsistency and settles on a single method. All other Schedule LLPS charges, including energy-based charges, are billed in addition. Dr. Berry testified that "the definition of the Minimum Monthly Bill does not include these charges; thus, these charges cannot be netted out."[120] Therefore, the energy charges are included as well.

The Minimum Demand of 80% of Contract Capacity in monthly billing will apply to every LLPS customer, and as Mr. Lutz testified, the Company would apply the method to other customers

[115] See LLPS Stipulation at ¶¶ 4–5.
[116] See Ex. 453, Berry Surrebuttal at 7; Ex. 57(HC)/58(P), Lutz Surrebuttal at 12; Ex. 138, Sarah Lange Rebuttal at 10.
[117] See Tr. Vol. 12 at 81:17–82:4 (Ives).
[118] See Tr. Vol. 7 at 197:19–25, 200:5–24 (Lutz).
[119] See LLPS Stipulation at ¶ 4.
[120] See Ex. 453, Berry Surrebuttal at 8.

in the future.[121] The change will raise LLPS bills during the ramp and would potentially "result in higher bills as a result of adding the variable energy cost on top of the minimum demand."[122] The Company will provide tariff redlines reflecting this change to Schedule LLPS.[123]

Staff's Proposed Schedule LLPS Modifications Are Unnecessary

Staff proposes several modifications to Schedule LLPS, which include adding construction power to the ramp period, bar contract-demand exceedance, and calculate the minimum bill "using 80% of the contract demand, without deduction for the energy charge amount or any other amount."[124] Ms. Lange reasons that without the construction-power change "the effective ramp period could extend in excess of the five years,"[125] and therefore criticizes the Company's billing method because it "nets out any revenue from energy sales ... against the minimum bill."[126]

However, per the LLPS Stipulation, energy-based charges are billed in addition to the minimum billing demand[127] of 80% of the annual Contract Capacity. The Minimum Demand also helps increase accountability for underutilization of receiving service by EMM for Schedule LLPS customers, thereby limiting the customer's use of on-site capacity.[128]

Regarding construction power, Mr. Lutz explained that it is separate from service under Schedule LLPS,[129] and the tariff already permits the capacity values in a service agreement to be revised.[130]

[121] See Tr. Vol. 7 at 200:19–201:4 (Lutz).
[122] See id. at 190:8–16 (Ives).
[123] See LLPS Stipulation at ¶ 5.
[124] See Staff Positions at 31.
[125] See Ex. 124, Sarah Lange Rate Design Direct at 6; id. at 8.
[126] See Ex. 138, Sarah Lange Rebuttal at 9–11.
[127] See LLPS Stipulation at ¶ 4; Tr. Vol. 12 at 94:5–11 (Ives).
[128] See Tr. Vol. 12 at 98:10–13, 99:7–22 (Ives).
[129] See Ex. 55(HC)/56(P), Lutz Rebuttal at 37.
[130] See Tr. Vol. 12 at 148:12–15 (Lutz).

The Commission should reject Staff's proposed Schedule LLPS modifications as they are addressed by the LLPS Stipulation and EMM's existing Schedule LLPS.

OPC's Schedule LLPS Modifications Are Duplicative and Recycled

The Commission should reject OPC's recycled Schedule LLPS modifications, consistent with the Large Load Order.[131] Those modifications are a minimum bill at 90%, a 20-year contract term, a 25 MW eligibility threshold, and a Community Benefits Rider. When asked by Chair Hahn whether any utility or state has adopted all three of OPC's changes to the minimum bill, contract term, and threshold, Dr. Marke identified none.[132]

The Commission should approve Evergy Missouri Metro's clarification of the Minimum Monthly Bill in its Schedule LLPS, per the LLPS Stipulation but nothing further at this time based on the evidence in the record and its prior order in Case No. EO-2025-0154.

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

The Commission should order no new large load reporting for Schedule LLPS customers.[133]

Less than a year ago, the Commission approved Evergy Missouri Metro's Global Stipulation. There, the Company agreed to meet with stakeholders, including Staff, OPC, and customers, to determine an annual compliance report to be provided to the Commission regarding LLPS customers.[134] The report will contain "(i) the number of new or expanded customers that have enrolled in Schedule LLPS and (ii) the total estimated load enrolled under Schedule LLPS."[135]

[131] See Large Load Order at 12–14, 44–46; Tr. Vol. 7 at 218:21–24 (Marke) (whether his testimony "repeats many of the same recommendations the Commission rejected less than a year ago," Dr. Marke answered, "That's correct.").
[132] See Tr. Vol. 7 at 222:23–224:15 (Marke).
[133] See Global Stipulation at ¶ 35.
[134] See Global Stipulation at ¶ 35.
[135] Id.

The Company has also committed to provide energy usage information on a confidential and anonymized basis, as well as meet with Staff and OPC at least annually to provide updates on EMM's Schedule LLPS.[136] The Company anticipates making individual service agreements available to the Commission and the parties on request, with confidentiality protections addressed case by case, and nothing in the LLPS Stipulation restricts the Commission's "right to access information."[137]

Staff's Reporting Requirements Are Premature and Unnecessary

Staff requests the Commission to require Evergy Missouri Metro to provide an annual compliance report and delivery of executed service agreements within 30 days of execution and hourly LLPS load in rate case workpapers.[138] Staff's requests are based on the Amended Non-Unanimous Global Stipulation and Agreement the Commission approved in Union Electric Company d/b/a Ameren Missouri's ("Ameren Missouri") large load customer tariff case, Case No. ET-2025-0184.[139] As Mr. Lutz explained, however, Ameren Missouri agreed to those provisions as part of a larger settlement.[140] And the Commission approved a different package of provisions for the Company. Indeed, Staff witness Claire Eubanks acknowledges that the Commission denied Staff's reporting requirements in Case No. EO-2025-0154.[141]

As to hourly LLPS load in workpapers, Mr. Lutz testified that to his "knowledge, no utility has filed a rate case inclusive of an LLPS customer, so to presume that inadequate data will be

[136] See Ex. 55(HC)/56(P), Lutz Rebuttal at 27.
[137] See LLPS Stipulation at ¶ 21.
[138] See Ex. 123, Eubanks Direct at 16; id. at 17; id. at 18.
[139] See Ex. 123, Eubanks Direct at 16–18; Amended Non-Unanimous Global Stipulation and Agreement at ¶¶ 37, 51, 52, No. ET-2025-0184 (Nov. 20, 2025) (the "Ameren Stipulation"), approved, Order Regarding Ameren Missouri's Request for Approval of a Large Load Rate Plan and Associated Variance at 4, 6–7, In re Application of Union Electric Company d/b/a Ameren Missouri for Approval of New Modified Tariffs for Service to Large Load Customers, No. ET-2025-0184 (Nov. 24, 2025) (the "Ameren Order").
[140] See Ex. 55(HC)/56(P), Lutz Rebuttal at 27.
[141] See Ex. 123, Eubanks Direct at 15.

offered in work papers is premature at best."[142] Indeed, Staff is requesting such information prior to a Schedule LLPS customer being included in EMM's test-year, less than one year after the Commission approved the Annual Reports provision in the Global Stipulation.

Staff also requests that the Company continue its 20 CSR 4240-3.190 reporting of LLPS hourly loads.[143] As Ms. Lange testified, the Company's monthly reports under 20 CSR 4240-3.190 already include LLPS hourly loads, information that "is available only to Commission Staff and the Office of the Public Counsel."[144]

OPC's Reporting Requirements Are Duplicative and Recycled

OPC requests the Commission to require Evergy Missouri Metro to provide independent studies of power usage effectiveness, water usage effectiveness, and total harmonic distortion, identical to its request in Case No. EO-2025-0154.[145] The Commission rejected the same studies in its Large Load Order, finding that the "studies proposed by OPC have not been identified as part of Evergy's industry reviews and do not appear to be a normal component of utility large load processes."[146] These studies "would make the process unduly onerous for large load customers, thereby creating barriers to entry."[147] Therefore, the studies "would be duplicative of efforts already performed by large load customers and Evergy."[148]

The Commission should reject OPC's duplicative and already denied reporting requirements.

[142] See Ex. 55(HC)/56(P), Lutz Rebuttal at 30.
[143] See Staff Positions at 33.
[144] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 9; Ex. 1 (Staff on-the-record Ex. 1 regarding 20 CSR 4240-3.190).
[145] See Ex. 202, Marke Direct at 25, 28, 31, 32; Ex. 204, Marke Surrebuttal at 24, 26.
[146] See Large Load Order at 31.
[147] See Ex. 22, Gunn Rebuttal at 5; Large Load Order at 33.
[148] See Large Load Order at 33.

The Commission approved the Annual Reports provision in the Global Stipulation in November 2025, and no Schedule LLPS customer is in Evergy Missouri Metro's test year. Therefore, the Commission should not approve additional LLPS customer reporting requirements.

25. Fuel Adjustment Clause — Large Load Power Service (EMM: Nunn, Ives, Gunn, Meitner, Foo; Staff: Mastrogiannis, Lange; Google: Berry; OPC: Schaben)

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

No. The Commission should only approve the changes to the FAC discussed in the LLPS Stipulation.[149] Schedule LLPS took effect in December 2025, after the test year ended, so this transitional case contains "no reliable data on how LLPS customers impact the class cost of service or the allocation of fuel cost through the FAC."[150] Without that data, the record cannot support restructuring a mechanism that Schedule LLPS was designed to apply in full, "with the explicit acknowledgement that the LLPS customers would be fully subject to the FAC and other generally available riders."[151] The LLPS Stipulation therefore keeps the current FAC structure for every customer and "reserves any broader changes for an evidentiary record that can support those broader changes."[152]

The LLPS Stipulation applies a 90/10% sharing mechanism for the share of load from Schedule LLPS customers while maintaining the 95/5% sharing mechanism for the share of load from all non-LLPS customers.[153] All customers, LLPS and non-LLPS, benefit from the higher Company sharing percentage that this proposal advances. All LLPS and non-LLPS FAC costs are totaled into one current period fuel adjustment rate, so all customers continue to pay one base factor

[149] See LLPS Stipulation at ¶¶ 6–10; id. at 5.
[150] See Tr. Vol. 12 at 39:20–23 (Google counsel)Tr. __:__ (Google counsel) see also Ex. 452, Berry Rebuttal at 5.
[151] See Ex. 72, Nunn Rebuttal at 7.
[152] See Tr. Vol. 12 at 43:23–44:1 (Google counsel) (statement of a party's position).
[153] See LLPS Stipulation at ¶ 7. The 90/10% sharing mechanism remains in place only until rates take effect in the next general rate case. Id. at ¶ 8.

and one fuel adjustment rate.[154] The LLPS Stipulation also keeps LLPS fuel costs out of the base factor and requires that they "flow through the FAC as actual net energy costs."[155]

Including LLPS Customers in the FAC Reflects the SPP Integrated Market

The Company serves all customers from one integrated system, and its generating units "are not dedicated to individual customers."[156] LLPS customers are part of that system. The Company bids their load into the SPP the same way it bids all of its load, and meets SPP resource adequacy requirements for them as it does for every other customer.[157] The Commission recognized that relationship when it approved Schedule LLPS, finding that data center customers "are economic and operational partners that provide important advantages to electric utilities."[158]

Because the system is integrated, the cost of serving LLPS and non-LLPS customers alike "consists primarily of the costs of running its own generators, which consist primarily of fuel costs."[159] The Company "sells the energy it produces from its generation fleet into the SPP markets at LMP prices and buys the energy it needs to serve its load from the SPP markets at LMP prices."[160] As a result, "sales revenue and purchase costs largely net out."[161] The cost that drives the FAC is the cost of operating the Company's own fleet.

Fleet fuel costs are the costs the FAC exists to recover, and the FAC should continue to apply to every customer class, including Schedule LLPS.[162]

Schedule LLPS customer load does not change that cost structure. In its Report and Order in Case No. EO-2025-0154, the Commission found that data centers "are consistent and predictable

[154] Id. at ¶¶ 7, 10.
[155] Id. at ¶ 9.
[156] See Ex. 72, Nunn Rebuttal at 5.
[157] See Tr. Vol. 12 at 70:16–24 (Ives); Ex. 31, Ives Surrebuttal at 8–9.
[158] See Large Load Order at 9 (Finding of Fact 8).
[159] See Ex. 65(C)/66(P), Meitner Surrebuttal at 5.
[160] Id.
[161] Id.
[162] See Ex. 72, Nunn Rebuttal at 6–7; Ex. 65(C)/66(P), Meitner Surrebuttal at 5.

consumers of energy."[163] Indeed, Schedule LLPS customers "operate pretty consistently over time," and "there are very few hours over the course of the year where they're straining above what the capabilities of our resource requirements are."[164] Outside a few hours when SPP is constrained, the Company meets the capacity and energy needs of LLPS customers with its own resources.[165] LLPS customers therefore draw on the same fleet as every other customer.

EMM's Schedule LLPS was designed for that integrated system, and LLPS customers pay the FAC charge today.[166] The Commission approved Schedule LLPS as a package, and participation in the FAC "was not an omission to be corrected here."[167] The LLPS Stipulation is the only proposal in this case that maintains the construct the Commission approved in Case No. EO-2025-0154. It continues LLPS participation in the FAC, keeps the four-part LLPS rate, and adds the earnings review contemplated for the first rate case with an LLPS customer in the test year.[168] LLPS customers should accordingly continue to participate in the FAC "as it was originally designed to do."[169]

The 90/10% Sharing Mechanism Is Beneficial to All Customers and the Company

The 90/10% sharing mechanism increases the Company's share of any FAC cost deviation associated with LLPS load.[170] A 95/5% sharing provision has historically applied to costs that deviate in an accumulation period from the level set in base rates.[171] However, the LLPS Stipulation includes that 95/5% sharing for all non-LLPS customers' kWh load, while calculating the share of any cost increment attributable to Schedule LLPS customers' kWh load on a 90/10%

[163] See Large Load Order at 9 (Finding of Fact 8(a)).
[164] See Tr. Vol. 12 at 71:4–9 (Ives).
[165] See Tr. Vol. 12 at 71:8–15 (Ives).
[166] See Ex. 30, Ives Rebuttal at 2; Tr. Vol. 8 at 10:9–20 (Nunn).
[167] See Ex. 30, Ives Rebuttal at 6.
[168] See Tr. Vol. 12 at 68:7–24 (Ives).
[169] See Tr. Vol. 12 at 67:8–12 (Ives).
[170] See LLPS Stipulation at ¶ 7.
[171] See Tr. Vol. 12 at 75:3–7 (Ives).

basis.[172] As a result, the Company bears 10%, rather than 5%, of the incremental FAC costs associated with LLPS load.[173]

Every customer shares in that term because the LLPS Stipulation combines both portions into a single rate. In each accumulation period, the LLPS Stipulation divides any deviation from the base between non-LLPS and LLPS customers by their kWh usage for that period.[174] When costs in an accumulation period exceed the base, the Company therefore absorbs a larger part of the LLPS-attributable increment. The single fuel adjustment rate that every customer pays is then lower than it would be under 95/5% sharing alone.[175] Because the 90/10% calculation is weighted by LLPS kWh, the overall sharing rises above 95/5%, and "ultimately all customers will participate in that differential."[176]

The effect grows as LLPS load grows. LLPS customers will receive a large amount of energy and, as a result, will pay a proportionately larger share of fuel costs.[177] As the LLPS share of each accumulation period's kWh rises, the part of any cost increment subject to 90/10% sharing rises with it, and the Company absorbs 10% of that larger part.[178] The 90/10% sharing mechanism also serves Staff's own rationale for sharing, which is that the 95/5% mechanism "forces the utility to have skin in the game."[179] Indeed, Staff acknowledges that the Commission has noted "there could be an argument for a 90%/10% split," and that a Black Hills Colorado tariff still shares fuel cost deviations on a 90/10% basis.[180]

[172] See LLPS Stipulation at ¶ 7; Tr. Vol. 12 at 75:7–13 (Ives).
[173] See Tr. Vol. 12 at 43:11–13 (Google counsel) (statement of a party's position).
[174] See LLPS Stipulation at ¶ 7.
[175] See LLPS Stipulation at ¶ 7; Tr. Vol. 12 at 75:14–18 (Ives).
[176] See Tr. Vol. 12 at 75:14–18 (Ives).
[177] See Ex. 22, Gunn Rebuttal at 17.
[178] See LLPS Stipulation at ¶ 7.
[179] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 9.
[180] Id. at 10–11.

Google, a signatory to the LLPS Stipulation, supports the 90/10% sharing mechanism as "an additional discount for customers" on FAC costs associated with LLPS load, and one that operates "above and beyond" the sharing that applies today.[181] Google's support "is not based on obtaining lower rates for LLPS customers."[182] To the contrary, the LLPS Stipulation raises what LLPS customers pay in two ways.[183] First, LLPS customers remain in the FAC "so that [Google] will pay the same per kilowatt-hour FAC rate as other customers."[184] Second, the LLPS Stipulation bills energy-based charges in addition to a billing demand of at least 80% of annual Contract Capacity, as discussed under Issue 31.[185] By contrast, as discussed below, Staff's Option 2 would remove the FAC charge from LLPS invoices, and Google declined that result because it "is not interested in short-term discounts that are based on fundamentally flawed methodology."[186]

Notwithstanding those benefits, Staff's objection contends that the 90/10% sharing mechanism "does not provide real value for ratepayers."[187] However, Staff's objection rests on illustrative kWh figures that are "hypothetical and easy round numbers."[188] The effect of the 90/10% sharing mechanism grows with the LLPS share of energy sales and with the size of the cost deviation.[189] Staff's own objection shows that growth. If LLPS customers were responsible for 50% of EMM's energy sales, customers would bear 95% of the non-LLPS half of a cost increment and 90% of the LLPS half. That is a combined customer share of 92.5%, so the Company's overall share would rise from 5% to 7.5%.[190] The 90/10% sharing mechanism

[181] See Tr. Vol. 12 at 43:9–15 (Google counsel).
[182] See Tr. Vol. 12 at 41:20–21 (Google counsel) (statement of a party's position).
[183] See Tr. Vol. 12 at 41:22–24 (Google counsel) (statement of a party's position).
[184] See Tr. Vol. 12 at 41:24–42:1 (Google counsel).
[185] See LLPS Stipulation at ¶ 4.
[186] See Vol. 12 at 40:14–20 (Google counsel).
[187] See Staff LLPS Objection at ¶ 8(b).
[188] See Tr. Vol. 7 at 122:24–123:5 (Sarah Lange).
[189] See LLPS Stipulation at ¶ 7.
[190] See Staff LLPS Objection at ¶ 8(b).

produces a modest effect today only because LLPS load is a modest share of EMM's energy sales today, and the effect increases as LLPS load ramps.

Moreover, the benefits of continuing to include LLPS customers in the FAC are not deferred to a future case. An LLPS customer is taking service and paying the fuel adjustment rate today, and its ramp continues.[191] Customer A will pay an energy rate that "will likely reduce the FAC Base Rate."[192] Net revenues from the LLPS customer, all else equal, also "would cause other ratepayers' rates to be lower than they otherwise would be."[193] And because increases in net fuel and purchased power costs "are generally accompanied by increases in associated energy sales,"[194] LLPS load supports future base rate revenues as well. Supporting the stipulation and agreement gives customers immediate benefit as well as one that grows in the future.

The LLPS Stipulation Does Not Double-Recover Fuel Costs

Staff, while presenting no analysis, contends that excluding LLPS energy from the base factor "allows EMM to unreasonably double-recover all LLPS energy expense."[195] Staff's double-recovery claim ignores how the FAC works. Every customer tariff, including Schedule LLPS, recovers base energy costs through base rates, and the FAC captures only changes from those base levels.[196] Under the LLPS Stipulation, LLPS customers pay their share of the revenue requirement and the base factor set in this case, just as all other customers do. They also pay through the FAC for any change in net fuel and purchased power cost.[197] The LLPS Stipulation reflects LLPS revenue, energy charges included, in the revenue requirement, while it leaves LLPS fuel out of the

[191] See Ex. 30, Ives Rebuttal at 11; Vol. 12 at 40:8–11, 46:23–47:1, 48:7–11 (Google counsel).
[192] See Ex. 452, Berry Rebuttal at 11.
[193] See Tr. Vol. 7 at 111:16–19 (Sarah Lange).
[194] See Ex. 72, Nunn Rebuttal at 12.
[195] See Staff LLPS Objection at ¶ 8(a).
[196] See Tr. Vol. 12 at 74:3–8 (Ives); Ex. 22, Gunn Rebuttal at 14.
[197] See Vol. 12 at 73:19–74:1 (Ives).

base factor and recovers that fuel through the FAC.[198] Because LLPS fuel cost enters the FAC only as actual net energy cost, there is "no way to double recover when you're aligning them through the FAC."[199] Indeed, Staff's own premise confirms the point, because current LLPS energy rates "are effectively a wash with the current and normalized level of energy expense to serve LLPS load," and the two "are basically the same number."[200] Any growth after the true-up is addressed by the LLPS Stipulation's earnings review.[201]

Staff's Option 1 Breaks Staff's Own Rule for the Base Factor

Staff's Option 1 includes LLPS customers in the FAC, but it adds to the base factor an annualized LLPS load and expense that Staff's own revenue requirement does not contain.[202] To estimate that expense, Option 1 uses locational marginal prices ("LMP") as a proxy for LLPS fuel costs, which is the same flaw that defeats Staff's Option 2.[203] Option 1 therefore breaks Staff's own rule that the base factor should rest on "the Base Energy Cost that the Commission includes in the revenue requirement" and should "accurately reflect what is in the . . . revenue requirement."[204]

Under Option 1, Staff "proposes to add estimated day-ahead energy expense and Customer A usage to the FAC base but not the corresponding costs in the revenue requirement."[205] Staff's revenue requirement contains no Customer A energy expense, because Staff's fuel and purchased power modeling "included Customer B at an annualized load, and did not include Customer A."[206]

[198] See LLPS Stipulation at ¶¶ 9, 13.
[199] See Vol. 12 at 73:19–74:2 (Ives).
[200] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 7; Tr. Vol. 7 at 256:20–257:3 (Sarah Lange).
[201] See LLPS Stipulation at ¶ 3, Ex. D.
[202] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 18; Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 43–44.
[203] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 43.
[204] See Ex. 111, Mastrogiannis Direct at 2; Tr. Vol. 7 at 257:13–17 (Sarah Lange).
[205] See Ex. 74, Nunn True-Up Rebuttal at 3.
[206] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 18.

Staff instead assumes that Customer A's energy revenues and energy expenses offset, and it found it "not necessary to adjust either expense or revenues to include Customer A energy usage in this case."[207] Option 1 nonetheless adds Customer A's estimated day-ahead energy expense and kWh to the base factor, so the Option 1 base factor would contain an expense that Staff's revenue requirement leaves out.[208] Staff's own testimony confirms the mismatch, because Staff's true-up base factor of $0.01901 per kWh "is applicable to FAC Option 2," the only option that ties to Staff's revenue requirement.[209]

The Option 1 expense is also an estimate built outside Staff's production cost model. Option 1 relies on a separate true-up plug based on contract demand and on an estimate of Customer A's load factor.[210] Staff "did not include large loads in its production cost modeling because the information needed to do so was not and is not available."[211] Staff's estimate of LLPS expense also depends on an assumption Staff itself distrusts, "an annualized level of energy consumption for Customer A," a customer that is still ramping.[212] By Staff's own account, "the actual hours of Customer A load cannot be reasonably normalized at this time," and "there is no available long-term hourly load shape for Customer A."[213] Staff's approach therefore "combines production cost model outputs with manual, out-of-model adjustments," so that "modeled revenues, modeled costs, and net system input assumptions are not treated consistently."[214] Staff annualizes Customer A's non-energy revenue but declines to model the costs of serving Customer

[207] See Ex. 170, Sarah Lange True-Up Rebuttal at 6; see also Ex. 74, Nunn True-Up Rebuttal at 3.
[208] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 43–44.
[209] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 19 n.14.
[210] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 18; Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 19, 22.
[211] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 18.
[212] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 3 & n.1.
[213] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 23, 43.
[214] See Ex. 74, Nunn True-Up Rebuttal at 5.

A.[215] By contrast, under the Company's approach, "[a] production cost evaluates the Company's generation and market activity in an integrated manner," capturing the revenue, cost, and system effects of Customer A's load together.[216]

Staff's Option 2 Substitutes the Market Price of Energy for the Cost of Producing It

Staff's flawed Option 2 removes LLPS customers from the FAC and replaces the Company's cost of serving them with a market price. Each month, Option 2 subtracts from Missouri jurisdictional energy expense each LLPS customer's hourly day-ahead load multiplied by the day-ahead LMP at EMM's load node. It also subtracts a share of load-side SPP charges allocated by LLPS kWh or kW.[217] Staff's use of LMPs "confuses the market price of energy with the cost of producing energy."[218]

The day-ahead LMP is the market-clearing price, typically set by the most expensive unit operating in the hour, and the Company's own cost of running its fleet may be lower or higher in any hour.[219] As a result, charging LLPS customers the LMP while incurring lower fuel costs produces "an over-recovery of costs," and charging the LMP while incurring higher fuel costs produces an under-recovery.[220] For the same reason, LLPS load times the day-ahead LMP "is an estimate of the market value of serving that load, but it does not identify the Company's actual cost of serving LLPS customers."[221]

Staff's Option 2 also ignores the revenue the Company earns from selling its own generation into SPP. Net fuel and purchased power has three parts: the cost to serve load at each

[215] See id. at 6.
[216] See Ex. 16(C)/17(P), Foo Rebuttal at 11; see also Ex. 74, Nunn True-Up Rebuttal at 6.
[217] See Ex. 111, Mastrogiannis Direct at 10–11.
[218] See Tr. Vol. 12 at 39:12–14 (Google counsel) (statement of a party's position); see also Ex. 452, Berry Rebuttal at 6–8.
[219] See Ex. 452, Berry Rebuttal at 8; Ex. 65(C)/66(P), Meitner Surrebuttal at 5.
[220] See Ex. 65(C)/66(P), Meitner Surrebuttal at 5; see also Ex. 452, Berry Rebuttal at 8.
[221] See Ex. 73, Nunn Surrebuttal/True-Up Direct at 12.

hour's LMP, the fuel for generation dispatched in the production cost model, and the revenue from energy sold.[222] Option 2 assigns LLPS customers only the cost to serve load and leaves the generation fuel and the sales revenue with other customers. The revenues from the generation the Company bids into SPP at the day-ahead LMP flows back to customers through the FAC, so each customer pays a net fuel and purchased power cost.[223] Pricing the LLPS class at the LMP without that netting "creates an imbalance."[224] Option 2 also denies LLPS customers the offset they pay for, because a LLPS customer "is paying for the ability to utilize that generation resource," and Staff's approach "doesn't allow for that."[225] If large customers are like all other customers, "then using a different method for determining their energy costs is unjustified."[226]

Option 2 also fails to isolate the costs it claims to. LLPS load "affects generation dispatch, fuel consumption, market purchases and sales, congestion and other SPP market activity," and "[t]hose effects cannot be reliably separated through a simple customer-specific allocation."[227] Staff nonetheless allocates SPP charges other than day-ahead energy by the LLPS share of Missouri jurisdictional kWh or kW, an allocation that "does not establish cost causation."[228] SPP settlement charges "do not move in proportion to any one customer's share of jurisdictional energy," so a customer with 10% of jurisdictional energy "does not necessarily cause 10% of a particular SPP charge."[229] Thus, Staff uses hourly load and hourly LMPs for one SPP charge and monthly allocation factors for every other.[230] Option 2 therefore "does not actually identify and

[222] See Tr. Vol. 12 at 168:4–16 (Sarah Lange).
[223] See Tr. Vol. 12 at 64:10–20 (Ives).
[224] See Tr. Vol. 12 at 64:21–65:4 (Ives).
[225] See Tr. Vol. 12 at 65:4–9 (Ives).
[226] See Ex. 65(C)/66(P), Meitner Surrebuttal at 5–6 (quoting Ex. 452, Berry Rebuttal at 7).
[227] See Ex. 16(C)/17(P), Foo Rebuttal at 22.
[228] Id.
[229] Id.; see also Ex. 30, Ives Rebuttal at 5–6.
[230] See Ex. 16(C)/17(P), Foo Rebuttal at 22–23.

remove the SPP costs caused by the Large Load Customers. Instead, it creates proxies for those costs and then removes the resulting allocated amounts from the FAC."[231]

Staff's Option 2 Leaves No Way to Recover Deviations from Base

Option 2 and the LLPS Stipulation treat LLPS costs the same way in base rates, because neither reflects LLPS fuel in the base factor.[232] The difference between Option 2 and the LLPS Stipulation lies in what happens after rates take effect. Under the LLPS Stipulation, a deviation from the base amount reflected in LLPS rates is trued-up through the FAC in later accumulation periods, "just like it does for all other customers."[233] Under Option 2, by contrast, "there's essentially a gap in any ability to recover costs that deviate from the base factor."[234] Indeed, Staff concedes the gap. Under Option 2, the Company would not recover through the FAC the difference between fuel and purchased power costs incurred and the amount in base rates. Nor would Option 2 capture the difference in costs and revenues relative to base rates.[235] Staff has offered no proposal "explaining how that same reconciliation process would operate for LLPS customers" once they leave the FAC.[236]

Moreover, Staff's analysis of Option 2 is incomplete. Staff has drafted no tariff for Option 2 and offered no exemplar.[237] Although Staff says a tariff would need only "another line," Staff proposed none.[238] Staff also issued no discovery to Google or Velvet Tech on the subject.[239] The Commission found the same deficiency in the Large Load Order, where Staff's alternate LLPS data was "based entirely on Staff's opinion" and "[t]he full impact of the Staff-proposed

[231] Id. at 23.
[232] See Tr. Vol. 12 at 71:21–72:2 (Ives).
[233] See Tr. Vol. 12 at 72:11–16 (Ives).
[234] See Tr. Vol. 12 at 72:3–8 (Ives).
[235] See Tr. Vol. 8 at 27:24–29:3, 29:18–31:23 (Mastrogiannis).
[236] See Ex. 72, Nunn Rebuttal at 7.
[237] See Tr. Vol. 8 at 29:4–13 (Mastrogiannis).
[238] See Tr. Vol. 8 at 33:9–25 (Mastrogiannis).
[239] See Tr. Vol. 8 at 26:4–8 (Mastrogiannis).

approaches has not been reconciled to the level required to effectuate the FAC."[240] The same is true of Option 2.

Removing LLPS Customers from the FAC Singles Out One Class Without a Cost Basis

Staff's Option 2 and OPC's exclusion proposal would each lift LLPS customers out of the integrated system that serves them.[241] OPC recommends exclusion first, with a separate base factor as its alternative, on the theory that non-LLPS customers are "subsidizing" the LLPS class.[242] Staff's Option 2, for its part, reflects a disagreement with LLPS participation in the FAC that began when the Commission approved Schedule LLPS and "has persisted in this docket."[243] Option 2 is accordingly "only an attempt to relitigate the LLPS structure that has already been approved."[244]

Neither Option 2 nor OPC's exclusion proposal reflects how the Company procures energy. The Company serves all customers from one integrated system, its generating units and purchased power transactions "are not dedicated to individual customers," and it "does not procure energy, purchased power, or capacity resources separately for LLPS customers and non-LLPS customers."[245] Removing LLPS customers from the FAC therefore "does not change what drives the costs."[246] Removing LLPS customers from the FAC instead singles out one class for different treatment with no difference in how that class's energy is procured.[247] The Commission has noted that FAC cost separation could occur if LLPS customers were registered as a separate pricing node, and that SPP voted down such a process.[248] Without separate settlement, "there is no accounting

[240] See Large Load Order at 39 (Finding of Fact 92).
[241] See Ex. 72, Nunn Rebuttal at 5; Ex. 73, Nunn Surrebuttal/True-Up Direct at 11.
[242] See OPC Positions at 10–11; Ex. 219, Schaben Surrebuttal at 2, 10.
[243] See Tr. Vol. 12 at 67:3–7 (Ives).
[244] See Ex. 63(C)/64(P), Meitner Rebuttal at 9.
[245] See Ex. 72, Nunn Rebuttal at 5; Ex. 73, Nunn Surrebuttal/True-Up Direct at 11.
[246] See Ex. 22, Gunn Rebuttal at 14.
[247] See Ex. 65(C)/66(P), Meitner Surrebuttal at 5–6 (quoting Ex. 452, Berry Rebuttal at 7).
[248] See Large Load Order at 40; Ex. 30, Ives Rebuttal at 5.

record that can be used to accurately separate actual LLPS net energy costs from the costs incurred to serve the remainder of Evergy's retail load."[249]

Excluding LLPS customers from the FAC also protects no one. The premise that excluding large loads protects other customers is "an incomplete perspective," because the FAC is one element in the broader balance of cost assignment under the LLPS tariff.[250] The record contains "no evidence that including Customer A in the FAC will harm other ratepayers in the test period calculations or in the new rate period," while "there is strong evidence that other ratepayers will benefit."[251] Removing LLPS customers from the FAC would instead "leave the Company with no way to recover the related net fuel costs" and would create "mismatches between the customers included in FAC costs, FAC revenues, FAC load determinants, and FAC base factors."[252] Exclusion "does not solve a cost-causation issue. Instead, it replaces the FAC's integrated cost recovery structure with a proxy methodology largely based on market-value assumptions."[253]

OPC's subsidy claim rests on the premise that LLPS customers are being underbilled.[254] The LLPS Stipulation resolves the billing question by billing energy-based charges in addition to a billing demand of at least 80% of annual Contract Capacity, as discussed under Issue 31.[255] Indeed, the Commission found that the features of Schedule LLPS "will make the LLPS class self-sustaining."[256] OPC also contends that if actual net energy costs include LLPS fuel costs, the base

[249] See Ex. 73, Nunn Surrebuttal/True-Up Direct at 12.
[250] See Ex. 22, Gunn Rebuttal at 14.
[251] See Ex. 452, Berry Rebuttal at 11.
[252] See Ex. 72, Nunn Rebuttal at 4–5; Ex. 74, Nunn True-Up Rebuttal at 5.
[253] See Ex. 74, Nunn True-Up Rebuttal at 5.
[254] See Ex. 219, Schaben Surrebuttal at 10.
[255] See LLPS Stipulation at ¶ 4.
[256] See Large Load Order at 26.

should include them as well.[257] That objection fails because the base factor leaves out LLPS fuel and LLPS kWh alike.[258]

The Commission should reject Staff's Option 1, Staff's Option 2, and OPC's exclusion proposal.

For these reasons, the Commission should find that LLPS customers should remain in the Company's single FAC, subject only to the FAC terms of the LLPS Stipulation.[259]

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

The Commission should order no new FAC reporting requirements beyond those in the Partial Stipulation.

The Partial Stipulation, which Staff signed, already resolves "[r]eporting requirements as illustrated in Stacy Henderson's direct testimony and Krishna Poudel's rebuttal testimony."[260] Those requirements include the 12 items in Ms. Henderson's direct testimony, which run from monthly SPP market settlements to the transmission congestion right ("TCR") and auction revenue right ("ARR") amounts attributed to each purchased power agreement.[261] Dr. Poudel's rebuttal adds an annual report on the Company's natural gas hedging plan, with projections of hedge ratio and expected price variability.[262] The Company accepts all of it, and the LLPS Stipulation, which also resolves Issue 25.B, adds no FAC reporting term.[263]

The Partial Stipulation also adds a factor "RR" for the return of revenues associated with new LLPS riders and a factor "RC" for the costs associated with approved LLPS riders.[264] The

[257] See OPC LLPS Opposition at ¶ 9.
[258] See LLPS Stipulation at ¶¶ 9–10.
[259] Id. at ¶¶ 6–10.
[260] See Partial Stipulation at ¶ 15.
[261] See Ex. 106, Henderson Direct at 9–10.
[262] See Ex. 143, Poudel Rebuttal at 6–7.
[263] See Ex. 72, Nunn Rebuttal at 17; LLPS Stipulation at 5.
[264] See Partial Stipulation at ¶ 15; Tr. Vol. 8 at 46:9–19 (Mastrogiannis).

RR and RC factors give the Commission and Staff a tariffed record of LLPS rider revenues and costs as they flow through the FAC.

Staff's LLPS-Specific Reports Serve Option 2 and Have No Use in a Single FAC

Staff nonetheless seeks additional LLPS-specific reports that exist only to implement Option 2. Staff asks for hourly LLPS loads with the settled day-ahead LMP at EMM's load node, monthly LLPS energy, Missouri jurisdictional energy, and SPP energy-based charges, and the same three items for coincident demand.[265] Staff recommends those reports "if Commission accepts Staff's option 2," and to support two separate FACs.[266] With LLPS customers in the single FAC under one base factor, Staff's stated reason for the LLPS-specific reports does not apply.

OPC "does not oppose additional reporting requirements" and asks that the reports in Ms. Henderson's direct testimony go to OPC as well as Staff.[267] The Company does not oppose providing its monthly FAC reports to OPC.

The Commission should find that no new FAC reporting requirements are needed beyond those in the Partial Stipulation.

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

No. The Commission should not order a separate FAC base factor for LLPS customers. The LLPS Stipulation instead provides one base factor and one fuel adjustment rate for all customers, which maintains "a common FAC framework for all customers, including LLPS customers."[268] A separate base factor would treat LLPS customers apart from the integrated system that serves them, even though Missouri ratemaking allocates costs among classes "through cost-of-service study and rate design."[269]

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[265] See Ex. 111, Mastrogiannis Direct at 11.
[266] See Ex. 111, Mastrogiannis Direct at 11; see also Ex. 142, Mastrogiannis Rebuttal at 9.
[267] See OPC Positions at 11; Ex. 218, Schaben Rebuttal at 4.
[268] See Ex. 31, Ives Surrebuttal at 9; LLPS Stipulation at ¶¶ 7, 10.
[269] See Ex. 22, Gunn Rebuttal at 15.

The Stipulated Base Factor Is Built from Staff's Own Inputs

The LLPS Stipulation sets the base factor at $0.01742 per kWh. It uses the net fuel costs in Staff's true-up EMS run and the net system input ("NSI") in Staff's FAC base rate calculation, adjusted to add the Company's long-term capacity sales.[270] The FAC has always included capacity purchases and sales with terms of a year or less, and the LLPS Stipulation adds the long-term contracts to the FAC, as discussed under Issue 23.D.[271] The long-term capacity sales belong in the stipulated base factor because, in Staff's own words, they "are already included in base rates."[272] As Staff's counsel put it and Mr. Ives agreed, the stipulated base factor is "the modified version of Staff's option 2," "[m]odified, with maintaining inclusion in the FAC."[273] Apart from the stipulated $0.01742 figure itself, Staff's reconciliation and the Company's position therefore do not differ.[274]

OPC's Separate Base Factor Would Split an Integrated Mechanism

OPC asks, if LLPS customers remain in the FAC, for "separate base factors for the LLPS customers and EMM's other customers."[275] Staff has calculated an LLPS-only factor of $0.030965 that "would include only LLPS energy expenses, and a reasonable proration of FAC-recoverable transmission expenses."[276] Staff's LLPS-only factor is not reduced by revenue from energy sold into the wholesale market, and it "does not include fuel expense to generate any energy sold into the wholesale market."[277] Staff's LLPS-only factor therefore omits two of the three parts of net fuel and purchased power, and because the calculation "is built upon Staff's DA LMP

[270] See LLPS Stipulation at ¶ 10; Tr. Vol. 12 at 96:13–18 (Ives).
[271] See Tr. Vol. 12 at 96:1–10 (Ives); LLPS Stipulation at ¶¶ 14–15.
[272] See Ex. 142, Mastrogiannis Rebuttal at 2.
[273] See Tr. Vol. 12 at 96:19–22 (Ives).
[274] See Tr. Vol. 8 at 75:14–23 (Niemeier).
[275] See OPC Positions at 10.
[276] See Ex. 138, Sarah Lange Rebuttal at 27–28.
[277] Id. at 28.

methodology, the resulting base factor inherits all of the deficiencies" of Option 2.[278] Indeed, Staff cannot calculate an LLPS-only base factor "that incorporates the LLPS responsibility for real time variations and the expenses associated with required ancillary services."[279]

A separate base factor also runs against the design of the FAC. The FAC "functions properly because the FAC is applied to the same customer population whose revenues were used to establish the FAC base factor."[280] Splitting the FAC customer population would require dividing costs that "are not naturally incurred in separate LLPS and non-LLPS buckets," because the Company does not procure energy or capacity separately for LLPS customers.[281] A separate LLPS base factor would still be built from system-wide production cost modeling and settlement information and then allocated down, because "granularity in the mechanism does not create it in the underlying data."[282] Any separate LLPS FAC "would necessarily depend upon proxies and allocations rather than an actual separation of the Company's net energy costs."[283] A separate LLPS base factor would be "a more complex mechanism with no corresponding improvement in the accuracy of cost recovery."[284]

Therefore, the Commission should not approve a separate FAC base factor for LLPS customers. Rather, the Commission should approve the LLPS Stipulation, under which one base factor of $0.01742 per kWh and one fuel adjustment rate apply to all customers.[285]

[278] See Ex. 65(C)/66(P), Meitner Surrebuttal at 7.
[279] See Ex. 138, Sarah Lange Rebuttal at 27.
[280] See Ex. 73, Nunn Surrebuttal/True-Up Direct at 11.
[281] Id.
[282] See Ex. 30, Ives Rebuttal at 6.
[283] See Ex. 73, Nunn Surrebuttal/True-Up Direct at 12.
[284] Id. at 13.
[285] See LLPS Stipulation at ¶¶ 7, 10.

37. Revenue Sharing (EMM: Gunn, Ives, Klote; Staff: Bolin; Google: Berry; MECG: Meyer; OPC: Nelson)

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?

Yes. The Commission should approve the Earnings Review Surveillance mechanism ("ERS") in the LLPS Stipulation (Exhibit D) as designed and reject the competing designs of Staff, OPC, and MECG.[286] Because Schedule LLPS load may continue to ramp after the June 30, 2026, true-up, LLPS revenue may grow faster than the costs reflected in rates before the next rate case.[287] Therefore, the ERS shares that growth with other customers through an annual review of actual results. It shares earnings only when the Company earns above its authorized ROE and LLPS revenue for the calendar year exceeds the LLPS revenue in EMM's revenue requirement.[288]

The Earnings Review Captures the LLPS Growth the Commission Anticipated

Schedule LLPS growth after the true-up is real but uncertain, because large load customers' views on the timing of their ramp, their growth, and their ultimate steady-state outcomes "move fairly frequently."[289] Indeed, in Staff's words, "customer growth can provide significant positive regulatory lag to the benefit of the utility."[290] As such, incremental LLPS revenues that begin outside the test year "are highly likely to outpace Evergy's incremental costs."[291]

The Commission anticipated this mechanism in its Large Load Order in Case No. EO-2025-0154. The Commission found that it "would have the authority to approve a similar mechanism in a future rate case after LLPS customers begin receiving service in Missouri."[292] The Commission reserved the question noting that it was "premature" to establish a mechanism "to

[286] See LLPS Stipulation at ¶ 3; id. at 5.
[287] See LLPS Stipulation at ¶ 1; Ex. 42, Klote Rebuttal at 3; Ex. 450, Berry Revenue Requirement Direct at 11.
[288] See LLPS Stipulation at Ex. D, ¶ (c); id. at ¶ 13.
[289] See Tr. Vol. 12 at 89:11–25 (Ives).
[290] See Ex. 138, Sarah Lange Rebuttal at 12.
[291] See Ex. 450, Berry Revenue Requirement Direct at 12.
[292] See Large Load Order at 43.

capture dollars that do not currently exist" because no customer was taking service under Schedule LLPS.[293] This case is that future rate case, because the Company's first Schedule LLPS customer began taking service after the test year and was billed within the true-up period.[294]

The Two-Trigger Design Measures Actual LLPS-Driven Growth

The ERS shares dollars only when two tests are satisfied.[295] First, the Company's earned return on equity for the calendar year must exceed the ROE authorized in this case by more than 20 basis points (the "Deadband").[296] Second, the LLPS base rate revenues collected during the year must exceed the LLPS revenue in the revenue requirement.[297] When both tests are met, the earned return above the Deadband, applied to the equity portion of rate base and grossed-up for income taxes, is shared 65/35%, with 65% to customers.[298] The customer share is "deferred as a regulatory liability to be returned to retail electric customers" as the Commission directs in a future rate case.[299] Any customer share above 50% is for the benefit of low-income customers, excluding funding for MEEIA low-income programs.[300] The portion of any shared amount attributable to PISA is returned over the period in which the associated PISA amounts are collected.[301] The ERS applies both tests to an annual ERS Report in the format of the surveillance reports the Company already files. That report may include CWIP for natural gas generation approved through a CCN under Section 393.135, including Mullin Creek No. 2, but may make no normalization or annualization adjustment.[302]

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[293] Id. at 44.
[294] See Ex. 30, Ives Rebuttal at 11; LLPS Stipulation at ¶ 13.
[295] See Tr. Vol. 12 at 76:11–16 (Ives); LLPS Stipulation at Ex. D, ¶ (c)(i)–(ii).
[296] See LLPS Stipulation at Ex. D, ¶ (c)(i).
[297] See LLPS Stipulation at Ex. D, ¶ (c)(ii); id. at ¶ 13.
[298] See LLPS Stipulation at Ex. D, ¶ (c)(i).
[299] See LLPS Stipulation at Ex. D, ¶ (c)(i).
[300] Id. at Ex. D, ¶ (c)(i).
[301] Id. at Ex. D, ¶ (c)(iii).
[302] See LLPS Stipulation at Ex. D, ¶ (a), (d)–(e); Ex. 23, Gunn Surrebuttal at 5–6.

The earnings test measures company-wide results, because "the Commission authorizes a return on equity for the Company as a whole," and a review of overall earned return "naturally incorporates all of these impacts."[303] Indeed, positive regulatory lag from LLPS growth "can be offset in whole or in part by additions to the cost of service that are required to serve that customer growth."[304] The LLPS revenue test then answers the concern that company-wide earnings "could potentially hide an LLPS-driven windfall," because sharing occurs only in a year of LLPS revenue growth above the $60 million base.[305] Excess earnings in a year without LLPS growth are attributable "to other Company-wide factors, such as weather, operating efficiencies, or variations in expenses," and no sharing occurs.[306] The ERS is also one-way, because customers share in returns above the authorized ROE, and the Company receives nothing under the ERS if it earns below the authorized ROE.[307]

The ERS Benefits Other Customers

Other customers will immediately begin receiving the benefits of LLPS load in this case. None of the Company's revenue requirement in this case is caused by Schedule LLPS customers, yet the LLPS Stipulation reflects $60 million of LLPS revenue in the revenue requirement, as discussed under Issue 3.A.[308] Because no new generation or transmission facilities are needed to serve Customer A in rates in this case, "all non-energy revenue from Customer A should fully offset the Missouri jurisdictional cost of service."[309] As such, other customers receive "an immediate benefit from large load customers in the form of a $60 million reduction in the revenue

[303] See Ex. 43, Klote Surrebuttal/True-Up Direct at 4–5.
[304] See Ex. 138, Sarah Lange Rebuttal at 12.
[305] See Ex. 209, Nelson Surrebuttal at 5; LLPS Stipulation at Ex. D, ¶ (c)(ii).
[306] See Ex. 43, Klote Surrebuttal/True-Up Direct at 11.
[307] See Tr. Vol. 12 at 77:15–19 (Ives); LLPS Stipulation at Ex. D, ¶ (c)(i).
[308] See Ex. 21, Gunn Direct at 17; Tr. Vol. 7 at 110:25–111:4 (Sarah Lange); LLPS Stipulation at ¶ 13.
[309] See Ex. 170, Sarah Lange True-Up Rebuttal at 6.

requirement," realized during the first year that rates from this case are in effect.[310] Net revenues from the LLPS customer, all else equal, "would cause other ratepayers' rates to be lower than they otherwise would be."[311]

The benefits continue as LLPS load grows. Schedule LLPS demand charges carry a premium over Large Power Service rates, and the Rate Design Settlement maintains that premium by raising LLPS rates to the same degree.[312] The Rate Design Settlement also assigns 94% of the system average increase to LLPS customers.[313] The LLPS premium then carries forward to the next EMM rate case, where other customer classes will be credited with the premium in the class cost of service study once LLPS customers are in the test-year.[314] Meanwhile, the LLPS ramp continues after true-up, and revenues from that ramp are available to be recognized in the ERS and shared with other customers.[315] The ERS therefore lets other customers participate in that upside while the Company keeps its incentive to attract and serve new load.[316]

Staff's Ameren Missouri Mechanism Would Not Improve the ERS

Staff objects to the ERS and requests the Commission to "order the same mechanism approved by the Commission for Ameren Missouri in Case No. ET-2025-0184."[317] However, Staff identifies no term of the ERS that it contends is unreasonable. Staff simply states that the Ameren Missouri mechanism "would provide consistency between Missouri's largest two electric utilities."[318]

[310] See Tr. Vol. 12 at 37:20–38:1, 47:2–10 (Google counsel).
[311] See Tr. Vol. 7 at 111:16–19 (Sarah Lange).
[312] See Tr. Vol. 12 at 47:11–20 (Google counsel).
[313] See Tr. Vol. 12 at 42:9–15 (Google counsel).
[314] See Tr. Vol. 12 at 42:16–20 (Google counsel).
[315] See Tr. Vol. 12 at 48:2–11 (Google counsel).
[316] See Tr. Vol. 12 at 43:5–8 (Google counsel); Ex. 23, Gunn Surrebuttal at 6–7.
[317] See Staff LLPS Objection at ¶ 4; Ex. 150, Bolin Surrebuttal at 3.
[318] See Staff LLPS Objection at ¶¶ 4–5; Ex. 150, Bolin Surrebuttal at 4.

The ERS already provides that consistency, because it is "very similarly situated and structured" to the Ameren Missouri mechanism.[319] Both mechanisms start from surveillance reporting and follow the same report and dispute schedule. Both condition sharing on large load base rate revenues exceeding the amount in rates, share 65/35% with the customer share above 50% directed to low-income customers, and end with the next general rate case.[320] The ERS is consistent but not identical to the LLPS tariffs that the Commission approved, and it need not be. There are four distinct differences which reflect the Company's individualized circumstances. First, the ERS measures earnings against the ROE the Commission authorizes in this case, instead of the midpoint of Staff's recommended ROE range in Ameren Missouri's prior rate case. Staff described its preferred sharing as "any amount over the authorized ROE."[321] Second, the 20 basis point Deadband is a negotiated term that aligns the ERS with Ameren Missouri while avoiding "undue incentive differences between" Evergy's Missouri and Kansas jurisdictions.[322] Staff's concern with the Deadband amounts to an estimate that the Company would keep "roughly $5 million" in a year in which both tests are met, and Staff's witness could not explain the reasoning behind the Deadband.[323] Third, the PISA provision returns sharing over the same 20-year period in which customers pay the deferral. A deferral recorded up front but recovered over 20 years otherwise "would create excess earnings and an earnings sharing reporting period."[324] Fourth, the CWIP provision carries into the earnings calculation any CCN determination under Section 393.135 for a natural gas generation facility in rate base, which existing surveillance reporting does not yet capture.[325]

[319] See Tr. Vol. 12 at 76:2–10 (Ives); Ameren Stipulation at ¶ 46; Ameren Order at 4, 7.
[320] See Ameren Stipulation at ¶ 46; Ex. 150, Bolin Surrebuttal at 3; LLPS Stipulation at Ex. D, ¶ (a)–(c), (f).
[321] See Ameren Stipulation at ¶ 46; Ex. 150, Bolin Surrebuttal at 3; Tr. Vol. 7 at 289:18–290:4 (Bolin).
[322] See Tr. Vol. 12 at 77:19–78:6 (Ives); Ex. 22, Gunn Rebuttal at 10.
[323] See Tr. Vol. 7 at 286:19–25, 289:4–11 (Bolin).
[324] See Tr. Vol. 12 at 78:7–25 (Ives); Ex. 43, Klote Surrebuttal/True-Up Direct at 11–12.
[325] See Tr. Vol. 12 at 79:25–80:18 (Ives); LLPS Stipulation at Ex. D, ¶ (d)(iv).

The Deadband and the 65/35% split also preserve the incentive the Commission has sought to protect. The Large Load Order approved Schedule LLPS in part because approval would "put Missouri on a level playing field with other states in seeking to attract large load customers."[326] Overly aggressive sharing mechanisms "can unintentionally reduce incentives for the investments" and economic development that benefit customers.[327]

MECG's Tracker Would Measure One Class Instead of the Company's Earnings

MECG requests the Commission to "authorize a one-way tracker of large load revenues."[328] Mr. Meyer, however, testified that he "would probably track it against the 60 million that you stipulated to at this point," which is the revenue requirement base the ERS would use.[329] A tracker looks only at the LLPS class and "does not consider other factors of the Company's revenue requirement," so a tracker would return LLPS revenue to customers even in a year in which the Company earned below its authorized ROE.[330] A single-class reconciliation "cannot capture those dynamics or yield a reliable measure" of whether the Company exceeded its authorized return, and deciding each year which costs are incremental to the class "invites a dispute every year."[331] Google likewise opposes the tracker because it "inappropriately targets class-specific earnings."[332] Indeed, the Large Load Order rejected Staff's one-way revenue tracker as "unreasonable," finding that a proposal requiring Evergy to absorb cost increases while deferring all of the resulting revenues is "inconsistent with balancing all parties' interests."[333]

[326] See Large Load Order at 25.
[327] See Ex. 43, Klote Surrebuttal/True-Up Direct at 12.
[328] See MECG Positions at 23; Ex. 301, Meyer Direct at 9–11.
[329] See Tr. Vol. 7 at 171:13–19 (Meyer); LLPS Stipulation at ¶ 13.
[330] See Ex. 304, Meyer Surrebuttal at 6; Ex. 22, Gunn Rebuttal at 7–8; Ex. 23, Gunn Surrebuttal at 4.
[331] See Ex. 23, Gunn Surrebuttal at 3, 6; Ex. 209, Nelson Surrebuttal at 3–4.
[332] See Ex. 454, Berry True-Up Rebuttal at 6.
[333] See Large Load Order at 27.

OPC's Alternatives Confirm the Earnings Review Design

OPC objects that the LLPS Stipulation "would adopt the methodology the Kansas Corporation Commission ordered."[334] However, OPC concedes that a company-wide earnings sharing mechanism "could be a reasonable alternative, with some modifications," and its modifications are an LLPS-only scope and a 10 basis point deadband.[335] The ERS supplies the LLPS-only scope through its LLPS revenue test, and OPC's request for a 10 basis point deadband confirms that a deadband belongs in the design.[336]

The Commission should therefore adopt Evergy Missouri Metro's ERS sharing mechanism per the LLPS Stipulation and Exhibit D.

II. NON-LLPS FAC ISSUES

The Company respectfully requests that the Commission keep the FAC's general construct and adopt the LLPS Stipulation's FAC terms on the base factor, sharing, and long-term capacity transactions. The Partial Stipulation, to whose FAC terms no party objected, resolves whether the FAC continues, which SPP charge types it includes, and the subaccount items other than the two addressed under Issue 23.C.[337] Issues 25.A and 25.C in Section I explain why LLPS customers should remain in the single FAC and how the stipulated base factor is built, so this Section does not repeat that analysis.

22. Fuel Adjustment Clause — Structure and Base Factor (EMM: Nunn, Ives, Meitner, Foo; Staff: Mastrogiannis; Google: Berry; OPC: Schaben)

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

No. Per the Partial Stipulation, the Company and Staff agreed that the "Company will not advance a position requesting 100% recovery of FAC cost in this case" as to non-LLPS

[334] See OPC LLPS Opposition at ¶ 3.
[335] See Ex. 209, Nelson Surrebuttal at 5–6, 10.
[336] See LLPS Stipulation at Ex. D, ¶ (c)(i)–(ii); Ex. 209, Nelson Surrebuttal at 6.
[337] See Partial Stipulation at ¶ 15; id. at 14; Amended Joint List at 3 n.10; Introduction, Section A.

customers.[338] No party provides an argument in this proceeding to change the current 95/5% FAC sharing mechanism for non-LLPS customers, therefore this issue is moot.

C. What value should the FAC base factor be set at the conclusion of this case?

As discussed in Section I, Issue 25.C, the FAC base factor should be $0.01742 per kWh, as provided in the LLPS Stipulation.[339] The FAC base factor is based on Staff's net fuel costs included in its true-up EMS filed in rebuttal, and the net system input. It adds the Company's long-term capacity sales at the June 30, 2026 true-up, which "are already included in base rates."[340] Including those sales lowers the base factor by $0.00104 per kWh, which is Staff's Missouri long-term capacity sales divided by the net system input in Staff's own base factor calculation.[341] Staff's witness also testified that the Company had no capacity purchases in the test year or update period.[342] Staff's witness explained to the Regulatory Law Judge that Option 2's base factor "does not include any annualized expenses or load for customer A." [343] The stipulated base factor likewise excludes the LLPS load and its cost, because the net fuel and net system input figures from Staff's model runs exclude them. [344]

Staff's objection calls the stipulated figure "artificially low,"[345] and OPC's opposition calls it "too low."[346] However, the base factor matches Staff's own revenue requirement, and Staff's own illustrations show "the importance of setting the Base Factor to match the Base Energy Cost in the revenue requirement used for setting general rates."[347] Including the true-up capacity sales

[338] See Staff Positions at 18; OPC Positions at 10; Partial Stipulation at ¶ 15.
[339] See LLPS Stipulation at ¶ 10.
[340] Ex. 142, Mastrogiannis Rebuttal at 2.
[341] See Ex. 169, Staff Accounting Schedules (True-Up), Sch. 9, line Rev-24 (Missouri jurisdictional long-term capacity sales of $9,412,309, account 447.016); Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 19 (net system input); LLPS Stipulation at ¶ 10.
[342] See Ex. 142, Mastrogiannis Rebuttal at 2.
[343] See Tr. Vol. 8 at 27:10–13 (Mastrogiannis).
[344] See Tr. Vol. 12 at 96:13–18 (Ives).
[345] Staff LLPS Objection at ¶ 7.
[346] OPC LLPS Opposition at ¶ 10.
[347] Ex. 111, Mastrogiannis Direct at 4; see id. at 2; Tr. Vol. 7 at 242:14–17 (Nunn).

is also necessary once the LLPS Stipulation adds long-term capacity sales to the FAC. Otherwise, customers would receive the benefit of the test-year sales twice. They would receive it once through base rates, and again through the FAC, which would treat the same sales revenue as an offset to actual net energy costs.[348]

The Commission should find that the $0.01742 per kWh base factor uses Staff's true-up net fuel costs and net system input and adds the Company's long-term capacity sales at the June 30, 2026, true-up, which are included in base rates in Staff's revenue requirement.

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

As discussed under Issue 22.B, the Commission should find that the Company's FAC sharing ratio should remain at 95/5% for non-LLPS customers. The LLPS Stipulation's 90/10% sharing applies to incremental costs allocated to LLPS kWh, as discussed under Issue 25.A in Section I.

23. Fuel Adjustment Clause — Included Costs (EMM: Nunn, Ives, Meitner, Foo; Staff: Mastrogiannis, Lange; OPC: Schaben)

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

Per the LLPS Stipulation, the Company proposes "to use Staff's percentage of transmission of 31.8%."[349]

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

The FAC should include Subaccounts 555006 and 447016 provided in the LLPS Stipulation regarding long-term capacity purchases and sales. Proposed Subaccount 555006 would record "capacity charges for capacity purchases greater than one year in duration," and proposed Subaccount 447016 would record "capacity charges for capacity sales greater than one year in

[348] See LLPS Stipulation at ¶¶ 10–11; Ex. 74, Nunn True-Up Rebuttal at 8.
[349] LLPS Stipulation at ¶ 12.

duration."[350] They parallel the existing subaccounts for capacity charges on purchases and sales of one year or less, Subaccounts 555005 and 447012, respectively.[351] Staff and OPC oppose the two subaccounts for long-term capacity purchases and sales, as discussed under Issue 23.D.[352]

The Commission should approve Subaccounts 555006 and 447016, in addition to the subaccounts in the Partial Stipulation.

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

Yes. The FAC should include long-term capacity purchases and sales, as the LLPS Stipulation provides.[353] Capacity costs separately recovered from an LLPS customer under an Interim Capacity Agreement would remain excluded.[354]

The current FAC tariff includes capacity charges for capacity purchases and sales of one year or less.[355]

The short-term (one year or less) capacity purchases are no longer adequate to measure how the Company must procure capacity. More stringent SPP reserve margin requirements and generation accreditation standards, combined with load growth, have shifted utilities away from having excess capacity.[356] The SPP market has become increasingly constrained, and long-term capacity contracts are becoming a more common tool for maintaining reliable service between rate cases.[357] Unlike the demand costs of owned generation, which remain relatively stable until new

[350] LLPS Stipulation at ¶ 11; Ex. 73, Nunn Surrebuttal/True-Up Direct, Sch. LJN-8, proposed Sheet Nos. 50.3–50.4.
[351] See P.S.C. MO. No. 7, Original Sheet Nos. 50.35–50.36, as reproduced in Ex. 73, Nunn Surrebuttal/True-Up Direct, Sch. LJN-8.
[352] See Staff Positions at 20; OPC Positions at 10.
[353] See LLPS Stipulation at ¶ 11.
[354] See Ex. 73, Nunn Surrebuttal/True-Up Direct at 5; Ex. 74, Nunn True-Up Rebuttal at 8.
[355] See P.S.C. MO. No. 7, Original Sheet Nos. 50.34–50.36, as reproduced in Ex. 73, Nunn Surrebuttal/True-Up Direct, Sch. LJN-8; Order Approving Four Partial Stipulations and Agreements at 2–3, 6–7, In re Evergy Missouri Metro Rate Increase, No. ER-2022-0129 (Sept. 22, 2022); Stipulation and Agreement at ¶ 6.b.14, In re Evergy Missouri Metro Rate Increase, No. ER-2022-0129 (Aug. 30, 2022).
[356] See Ex. 72, Nunn Rebuttal at 20–21.
[357] See Ex. 72, Nunn Rebuttal at 23.

assets are added or rates are reset, market capacity costs are "externally determined wholesale market expenses."[358] They change with market conditions, accreditation requirements, reserve requirements, and resource adequacy standards.[359]

Staff's Objections Misread the Base Factor and the Purpose of Interim Capacity

Staff contends that no long-term capacity purchases are known and measurable for the base factor.[360] The issue, however, is whether prudently incurred long-term capacity costs and revenues should be eligible for FAC treatment when such transactions occur.[361] The base factor reflects each side at its test-year level. The test year has no long-term capacity purchases, and the actual long-term capacity sales are in base rates.[362] Changes from those levels would then flow through the FAC as they occur, subject to its existing review, prudence determinations, and true-ups.[363]

Staff predicts that EMM's long-term capacity costs and revenues will change after rates become effective because the Company's projected demand shows a capacity need that "will increase slightly starting in 2027 and increase more drastically by 2028."[364] Indeed, the Company's long-term capacity sales will likely decrease after rates take effect in this case, and it will then add long-term capacity purchases, if necessary.[365]

Section 386.266.1 authorizes periodic rate adjustments outside general rate proceedings "to reflect increases and decreases in [the utility's] prudently incurred fuel and purchased-power costs, including transportation."[366] Long-term capacity purchases are purchased-power costs within that

[358] Ex. 73, Nunn Surrebuttal/True-Up Direct at 9.
[359] Id.
[360] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 17.
[361] See Ex. 74, Nunn True-Up Rebuttal at 7.
[362] See Ex. 142, Mastrogiannis Rebuttal at 2; Tr. Vol. 7 at 242:22–243:3 (Nunn).
[363] See Ex. 72, Nunn Rebuttal at 24.
[364] Ex. 142, Mastrogiannis Rebuttal at 2.
[365] See Tr. Vol. 7 at 252:21–253:7 (Mastrogiannis).
[366] Section 386.266.1. (Rate schedules for interim energy charges or periodic rate adjustment — application for approval, procedure — adjustment mechanisms — rulemaking authority — task force to be appointed — surveillance monitoring, requirements.).

authorization. And the FAC "exists because certain costs can change significantly between rate cases, creating substantial regulatory lag."[367] Because Staff itself anticipates significant changes in these costs between rate cases, including long-term capacity purchases in the FAC would serve exactly that purpose by reducing regulatory lag. Permitting long-term capacity purchases and sales "would allow both prudently incurred capacity costs and associated capacity revenues to be reflected consistently as they occur," consistent with and subject to prudence reviews.[368]

Staff further contends that capacity procured specifically for new LLPS customers should be borne by those customers. If LLPS rates do not cover their costs, Staff would have EMM recover its capacity purchases through the Interim Capacity provision of Schedule LLPS rather than the FAC.[369] Staff misunderstands the Interim Capacity provision.

Chair Hahn asked why capacity and energy purchased for large users would not all be assigned to those users.[370] The Interim Capacity provision "is not a general mechanism for assigning all future capacity purchases associated with load growth to LLPS customers."[371] It "is voluntary and applies only during an interim period during which the Company cannot serve large load with existing system capabilities."[372] The long-term capacity the LLPS Stipulation addresses is procured for all EMM customers. Long-term capacity resources "are not obtained solely for a single customer" and are procured to support the reliability needs of the Company's system as a whole.[373]

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[367] Ex. 73, Nunn Surrebuttal/True-Up Direct at 8.
[368] Ex. 74, Nunn True-Up Rebuttal at 8. The Commission's rule defines fuel and purchased power costs as "prudently incurred and used fuel and purchased power costs." See 20 CSR 4240-20.090(1)(L) (Fuel and Purchased Power Rate Adjustment Mechanisms).
[369] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 16; Ex. 142, Mastrogiannis Rebuttal at 7; Staff LLPS Objection at ¶ 13.
[370] See Tr. Vol. 12 at 44:12–20 (Chair Hahn).
[371] Ex. 73, Nunn Surrebuttal/True-Up Direct at 5.
[372] Google Positions, Issue 23.D; see Ex. 453, Berry Surrebuttal at 13.
[373] Ex. 73, Nunn Surrebuttal/True-Up Direct at 10.

Staff also contends that including long-term capacity tied to load growth in the FAC would produce double recovery.[374] That argument rests in part on the premise that revenues from new load will cover the cost of new capacity.[375] However, the demand charges in rates "are not specifically designed to track future market-based capacity costs that may arise after rates are established."[376] Incremental revenues must also support transmission, distribution, operations and maintenance, and the other costs of service.[377]

Finally, Staff contends that, as the Company's capacity sales decline and the same capacity serves growing LLPS load, the Company would earn more through retail rates while recovering the lost sales revenue through the FAC.[378] The FAC already treats a change in short-term capacity sales revenue in Subaccount 447012 as a change in actual net energy costs, and the LLPS Stipulation treats long-term sales the same way.[379] The LLPS Stipulation addresses LLPS revenue growth through the ERS. The ERS applies when actual LLPS base rate revenues exceed the amount in rates and the Company's earned return exceeds its authorized ROE by more than the 20 basis point Deadband. It then defers a 65% share of the excess earnings to return to customers.[380]

Capacity Charges Already Flow Through the FAC, and OPC's 2007 Aquila Order Predates the SPP Market

OPC contends that long-term capacity purchases and sales are not fuel and purchased power costs eligible to flow through the FAC.[381] In doing so, OPC relies on the Commission's 2007 Report and Order in an Aquila, Inc. ("Aquila," now Evergy Missouri West) rate case.[382]

[374] See Staff LLPS Objection at ¶ 11.
[375] See Ex. 142, Mastrogiannis Rebuttal at 6–7; Ex. 138, Sarah Lange Rebuttal at 25–26.
[376] Ex. 73, Nunn Surrebuttal/True-Up Direct at 6.
[377] See id. at 8.
[378] See Staff LLPS Objection at ¶ 12.
[379] See P.S.C. MO. No. 7, Original Sheet No. 50.36, as reproduced in Ex. 73, Nunn Surrebuttal/True-Up Direct, Sch. LJN-8; LLPS Stipulation at ¶ 11.
[380] See LLPS Stipulation at ¶ 3 & Ex. D; Section I, Issue 37.
[381] See OPC LLPS Opposition at ¶ 11.
[382] See Ex. 217, Schaben Direct at 14.

There, the Commission denied Aquila's request for FAC recovery of short-term capacity contracts for demand charges, finding that demand charges "are fixed costs to reserve capacity, and as such are more like plant investment cost than fuel or purchased power cost," and that "[t]his is the case irrespective of the length of the purchased power contract."[383]

The Company's FAC, however, already covers capacity charges on purchases and sales of one year or less, and the Commission "has continued to refine and update FACs as wholesale electric markets have evolved."[384] The 2007 order also predates the SPP integrated marketplace, which began operating in March 2014.[385]

The Commission should permit EMM to include long-term capacity purchases and sales for recovery in its FAC, subject to the Commission's prudence review.

III. COST OF CAPITAL

Introduction

The significant economic and geopolitical events that have occurred since this case was filed on February 6, 2026, reinforce that it is appropriate for the Commission to approve a return on equity in the range of 10.25% to 11.25%, as proposed by the Company's cost of capital witness Ann Bulkley. Additionally, the Company carries business risk above its peers: a large capital program, partial and delayed recovery under PISA, nuclear operations, and an FAC that leaves 5% of fuel cost variance with the Company.[386] Indeed, utilities with nuclear operations have been authorized an average ROE 37 basis points above the industry average.[387] In line with Ms.

[383] Report & Order at 43–44, In re Aquila, Inc. Tariffs Increasing Electric Rates, No. ER-2007-0004 (May 17, 2007), as quoted in Ex. 217, Schaben Direct at 14.
[384] P.S.C. MO. No. 7, Original Sheet Nos. 50.35–50.36, as reproduced in Ex. 73, Nunn Surrebuttal/True-Up Direct, Sch. LJN-8; Ex. 72, Nunn Rebuttal at 20.
[385] See Ex. 73, Nunn Surrebuttal/True-Up Direct at 2.
[386] Ex. 49 at 4, Ley Direct.
[387] See Ex. 49, Ley Direct at 4; Ex. 52, Ley Surrebuttal at 7–8.

Bulkley's recommendation, the Commission should therefore authorize an ROE of 10.50%.[388] Such a decision is necessary to permit Evergy Missouri Metro to remain financially sound and to attract investors while the Company executes its strategic investment plan that will provide customers with reliable, sustainable, and affordable energy.

The capital structure should be the Company's actual per-book structure at true-up: 52.19% common equity and 47.81% long-term debt.[389] Staff recommends the same.[390] OPC would instead impute an adjusted version of Evergy, Inc.'s consolidated structure, 45% equity and 55% debt.[391] The Company issues its own debt, carries no parent guarantee, and holds stand-alone credit ratings stronger than its parent's.[392] The cost of debt, 4.54%, is not in dispute.[393]

For the authorized ROE, Staff witness Dr. Seoung Joun Won recommends 9.73%; however, as discussed further below, he rests that figure on a single bond yield risk premium analysis.[394] His own discounted cash flow result is 8.18%, and the average of his DCF and capital asset pricing model results is 8.67%. Both are below any ROE authorized for a vertically integrated electric utility since 1980.[395] OPC witness David Murray recommends 9.25%, a figure none of his own studies supports.[396] Dr. Won's analysis should be given limited weight given his narrow analysis, however, his midpoint of 9.73% should be updated to reflect higher authorized levels for

[388] Ex. 9 at 11, Bulkley Rebuttal.
[389] Ex. 53 at 1-2, Ley True-Up Rebuttal; Ex. 52 at 2-3, Ley Surrebuttal.
[390] Ex. 165 at 62, Won Surrebuttal/True-Up Direct.
[391] Ex. 205 at 46-47, Murray Direct.
[392] Ex. 52 at 3, Ley Surrebuttal; Ex. 51 at 4-5, Ley Rebuttal; Ex. 165 at 62, Won Surrebuttal/True-Up Direct.
[393] Ex. 53 at 2, Ley True-Up Rebuttal; Ex. 165 at 63, Won Surrebuttal/True-Up Direct; Ex. 207 at 8, Murray Surrebuttal/True-Up Direct.
[394] Ex. 120 at 54-57, Won Direct; Ex. 165 at 63, Won Surrebuttal/True-Up Direct.
[395] Ex. 165 at 63 (Table 5), Won Surrebuttal/True-Up Direct (8.18% DCF, 9.16% CAPM, and 8.67% average); Ex. 9 at 19, Bulkley Rebuttal (the 8.18% result is below the lowest ROE authorized for a vertically integrated electric utility since at least 1980).
[396] Ex. 205 at 33, 43, 45, Murray Direct.

other vertically integrated utilities and changes in market conditions since December 2025; Mr. Murray's unsupported recommendation should be disregarded.

There is no dispute that interest rates continue to rise. Staff's and OPC's recommendations of 9.73% and 9.25%, respectively, are based on analyses that have not changed since December 2025. However, between December 31, 2025, and the June 30, 2026, true-up, the 30-year Treasury yield rose 7 basis points and the 10-year Treasury yield rose 26 basis points. Since the true-up, interest rates and the costs of raising capital have continued to rise. Between June 30 and October 30, 2026, the 30-year Treasury yield rose 40 basis points and the 10-year Treasury yield rose 50 basis points.[397]

During a time in which Evergy Missouri Metro is striving to achieve its strategic goal of providing reliable, sustainable, and affordable energy to customers, it must be provided with an ROE that reflects market conditions and the competition it faces for capital. Yet, despite these dynamic times, in which a powerful American economy continues to be vexed with rising inflation and interest rates, the ROE recommendations of Dr. Won for Staff and Mr. Murray for OPC have remained static since they filed direct testimony based on data as of December 2025. As discussed below in Subsection C, the Commission should instead adopt an authorized ROE that reflects national averages, market conditions, the challenges of the future, as well as the fact that the

[397] See supra note 57; Ex. 11 at 2, Bulkley True-Up Rebuttal (30-year Treasury yield of 4.91% on June 30, 2026). The Commission is required to take official notice of these facts pursuant to Section 536.070(6) of the Missouri Administrative Procedure Act, as they are "matters of which the courts take judicial notice." Environmental Utilities, LLC v. PSC, 219 S.W.3d 256, 265 (Mo. App. W.D. 2007). See Estate of Layne v. Williams, 727 S.W.2d 157, 159 (Mo. App. W.D. 1987) (U.S. Dep't of Treasury regulations). Such matters include government agency reports and data published on their websites. See Missourians for Fiscal Accountability v. Klahr, 830 F.3d 789, 793 (8th Cir. 2016) (courts may take judicial notice of information on government websites).

Company's current rates, unchanged since early January 2023,[398] are lower than those of comparable utilities.[399]

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

Evergy Missouri Metro proposes to use its actual per book capital structure as of the true-up period ending June 30, 2026. This will reflect the actual cost of capital specific to the Company, rather than the consolidated capital structure of its parent holding company Evergy, Inc.[400] Based upon its actual per book capital structure at true-up, EMM's common equity should be set at 52.19% and its long-term debt at 47.81%.[401] These are the percentages that Staff recommends as well.[402]

However, OPC witness David Murray recommends using his adjusted version of the capital structure of Evergy, Inc., rather than that of Evergy Metro, Inc.[403] As EMM's Treasurer Geoffrey Ley testified, Mr. Murray's proposed 45% equity ratio is more than 700 basis points below EMM's recommendation before true-up and more than 638 basis points below Dr. Won's recommendation before true-up.[404] Dr. Won also rejected Mr. Murray's recommendation, stating that using the parent company's capital structure instead of a utility subsidiary's structure for ratemaking "is not consistent with typical regulatory practices."[405]

[398] See Order Approving Compliance Tariffs at 3, In re Evergy Missouri Metro Rate Increase and Evergy Missouri West Rate Increase, Nos. ER-2022-0129 and ER-2022-0130 (Dec. 30, 2022) (tariff sheets approved to become effective January 9, 2023).
[399] Ex. 31 at 3, Ives Surrebuttal; Ex. 21 at 12-13, Gunn Direct.
[400] Ex. 53 at 1-2, Ley True-Up Rebuttal; Ex. 52 at 2-3, Ley Surrebuttal.
[401] Ex. 53 at 2, Ley True-Up Rebuttal.
[402] Ex. 165 at 62, Won Surrebuttal/True-Up Direct.
[403] Ex. 205 at 46-47, Murray Direct.
[404] Ex. 51 at 3, Ley Rebuttal.
[405] Ex. 145 at 52-53, Won Rebuttal.

Both Mr. Ley and Dr. Won rely on the guidelines of the Society of Utility & Regulatory Financial Analysts ("SURFA") which the Commission applied in Spire Missouri's 2021 general rate case:

- Whether the subsidiary utility obtains all of its capital from its parent, or issues its own debt and preferred stock;
- Whether the parent guarantees any of the securities issued by the subsidiary;
- Whether the subsidiary's capital structure is independent of its parent (i.e., existence of double leverage, absence of proper relationship between risk and leverage of utility and non-utility subsidiaries); and
- Whether the parent (or consolidated enterprise) is diversified into non-utility operations.[406]

EMM satisfies these guidelines as a wholly-owned operating subsidiary of Evergy, Inc. Credit rating agencies have assigned the Company a stand-alone credit profile that is equal to or stronger than Evergy, Inc.'s consolidated rating. As both Mr. Ley and Dr. Won have noted, Standard & Poor's ("S&P") rates EMM at "A-" compared with Evergy, Inc. at "BBB+"; similarly, Moody's rates EMM at "Baa1" versus Evergy at "Baa2."[407] These distinct and superior ratings reflect the credit markets' recognition that the Company's capital structure is independent of the capital structure of its parent.

OPC has argued that the Company engages in leverage arbitrage by maintaining a conservative subsidiary structure while carrying higher leverage at Evergy, Inc. However, the fact is that EMM's ratepayers benefit from the lower financial risk and the corresponding lower cost of debt that the Company's strong stand-alone capital structure supports.[408] If the Commission were to impute Evergy, Inc.'s debt to EMM, its actual cost of capital would not decrease. Instead, it would simply *understate* the equity that protects the Company's bondholders and supports its

[406] Ex. 51 at 4-5, Ley Rebuttal; Ex. 52 at 3, Ley Surrebuttal; Ex. 145 at 52-53, Won Rebuttal; Ex. 165 at 54, 62, Won Surrebuttal/True-Up Direct. See Amended Report & Order at 84-85, In re Spire Mo. Inc.'s Request for a Gen'l Rate Increase, No. GR-2021-0108 (Nov. 12, 2021).
[407] Ex. 51 at 4, Ley Rebuttal; Ex. 120 at 42-43, Won Direct.
[408] Ex. 51 at 5, Ley Rebuttal. See Ex. 205 at 48-53, Murray Direct.

credit ratings. Moreover, contrary to Mr. Murray's contention that regulatory commissions consider parent company capital structures when determining rates, Evergy, Inc.'s review of 109 rate case decisions as part of a November 2024 workshop at the Kansas Corporation Commission produced no evidence of holding company debt being attributed to subsidiary utilities in rate case decisions.[409] This review showed that Evergy, Inc.'s consolidated capital structure is consistent with peer norms, just as Ms. Bulkley's analysis indicated that the Company's stand-alone capital structure is consistent with its peer utilities.[410]

OPC also complains about the capital flows between EMM and its parent, and the Company's use of money pool borrowings, yet these practices are entirely consistent with normal utility practices.[411] As Mr. Ley explained, Evergy, Inc. and each of its utility subsidiaries, including Evergy Missouri Metro, file regular financial statements in accordance with Generally Accepted Accounting Principles which disclose inter-company financial transactions. Evergy, Inc.'s money pool is administered subject to FERC authorization and practices, and its loans are temporary in nature. They are generally undertaken when the pool minimizes the borrowing costs of its utility subsidiaries to the benefit of customers. When these transactions occur, they are done on an arm's length basis, are thoroughly documented, and are disclosed in Evergy, Inc.'s and its subsidiaries' financial statements.[412]

There is no good reason why the Commission should not set the capital structure of Evergy Missouri Metro based upon its actual structure. In contrast, the reasons for using the actual capital structure are clear:

- It is consistent with how EMM is financed which is the threshold test used by other regulatory commissions, including FERC;

[409] Ex. 51 at 5-6, Ley Rebuttal. See Ex. 205 at 47-48, Murray Direct.
[410] Ex. 51 at 6, Ley Rebuttal; Ex. 7 at 51-52, Bulkley Direct.
[411] Ex. 51 at 6, Ley Rebuttal; Ex. 205 at 58-60, Murray Direct.
[412] See Ex. 51 at 6, Ley Rebuttal.

- It is consistent with the average actual equity ratios of the utility operating companies in Ms. Bulkley's proxy group; and
- It is consistent with the capital structures that have recently been authorized for vertically-integrated electric utilities.[413]

OPC's proposal to use Evergy Inc.'s capital structure which, with adjustments, produces a contrived structure of 45% equity and 55% debt should be rejected. As Dr. Won testified, OPC's proposal is "based on assumptions that are not supported by conclusive evidence."[414] What's more, such a reduction in the Company's equity ratio could lead to an increase in the cost of debt which may ultimately increase customer rates.[415]

When faced with a party's complaint of error that its proposed hypothetical structure was rejected by the Commission, the Court of Appeals observed in affirming the Commission's decision that the party could cite "no cases where using an applicant's actual capital structure for ratemaking purposes has been held an abuse of discretion."[416]

Based on the recommendations of Evergy Missouri Metro and Staff, the Commission should approve a capital structure of 52.19% equity and 47.81% long-term debt.

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

The Company, Staff, and OPC agree that 4.54% is the cost of debt that should be used to determine EMM's rate of return.[417]

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

The Commission must determine what ROE will permit the Company to continue to attract investors while reflecting the concerns and interests of customers. This means striking the

[413] Ex. 9 at 77-78, Bulkley Rebuttal.
[414] Ex. 145 at 57, Won Rebuttal.
[415] Ex. 145 at 51, Won Rebuttal.
[416] State ex rel. Missouri Office of the Public Counsel v. PSC, 293 S.W.3d 63, 84 (Mo. App. S.D. 2009).
[417] Ex. 53 at 2, Ley True-Up Rebuttal; Ex. 165 at 63, Won Surrebuttal/True-Up Direct; Ex. 207 at 8, Murray Surrebuttal/True-Up Direct.

appropriate balance among the recommendations presented to it by three experts in the context of economic data and trends. The Commission's decision must be at a point within the zone of reasonableness that reflects the risks faced by the Company and be consistent with ROEs recently determined by other regulatory utility commissions for comparable companies.

1. Governing Legal Principles

The United States Supreme Court established the requirements for determining the reasonable rate of return in the long recognized Bluefield and Hope cases.[418] The fixing of "just and reasonable" rates involves a balancing of investor and consumer interests.[419] "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."[420] This includes an assessment of both utilities and non-utilities with whom the Company competes for capital.[421]

"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 ...."[422] A key concern in setting the appropriate return on common equity is that the return be reasonably sufficient to

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[418] Bluefield Water Works & Improv. Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679, 692 (1923); Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).
[419] Hope, 320 U.S. at 603. See State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 574-75 (Mo. App. W.D. 2009) (discussing zone of reasonableness and national average ROEs). Accord § 386.610 ("substantial justice between patrons and public utilities").
[420] Bluefield, 262 U.S. at 692.
[421] The Commission has found in the past that a Missouri utility was seeking "to raise capital across the entire nation." State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 574 (Mo. App. W.D. 2009). As Dr. Roger Morin, whose texts are relied upon by both EMM and Staff, has stated: "Utilities must compete with utilities and non-utilities to obtain capital, a reality recognized in the landmark Hope and Bluefield cases. *There is no restriction to other utilities.* It stands to reason that utilities must offer returns that are risk-comparable to competing investments. *Otherwise, capital will simply go somewhere else*." Roger A. Morin, Modern Regulatory Finance at 436 (2021) (emphasis added). See Ex. 9 at 23, 62, Bulkley Rebuttal; Ex. 145 at 13, 21-22, Won Rebuttal.
[422] Bluefield, 262 U.S. at 692.

maintain the financial health of the utility. "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."[423]

As the Hope Court explained:

> [T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[424]

The Bluefield Court stressed this point, declaring:

> Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors.[425]

While Hope and Bluefield require that investor and customer interests be balanced in setting a reasonable rate of return, neither decision enunciated a specific methodology to arrive at a reasonable ROE. "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. … It is not theory but the impact of the rate order which counts."[426]

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[423] Bluefield, 262 U.S. at 693.
[424] Hope, 320 U.S. at 603 (citation omitted).
[425] Bluefield, 262 U.S. at 694.
[426] Hope, 320 U.S. at 602 (citations omitted).

Following Bluefield and Hope, Missouri appellate courts agree that "the Commission is not bound to any set methodology in ensuring a just and reasonable return in setting rates."[427] In performing its duty, the Commission is bound to set a rate of return that falls within a zone of reasonableness: "Statutory reasonableness is an abstract quality represented by an area rather than a pinpoint. It allows substantial spread between what is unreasonable because too low and what is unreasonable because too high."[428] Stated differently, the zone of reasonableness is "the zone between the lowest rate not confiscatory and the highest rate fair to the public."[429]

2. Business Risk

In addition to the risks posed by current market conditions, including elevated long-term Treasury yields and a correspondingly higher cost of capital, the Company also faces moderately higher business and regulatory risks than many of its peers. These risks are driven by EMM's substantial capital expenditures, partial and delayed recovery under plant in service accounting, nuclear power operations, and a fuel adjustment clause whose 95/5% "sharing" mechanism does not allow full recovery of fuel costs.[430] The evidence shows that states with nuclear operations in investor-owned, vertically integrated utilities have historically authorized an average ROE of 10.04%, compared with an average ROE of 9.67% across all states. This 0.37% premium reflects the unique risks that credit rating agencies and investors recognize when it comes to utility ownership of nuclear generating assets, including waste storage obligations, operational complexity, decommissioning liabilities, and environmental compliance.[431] All of these financial and operational risks are borne by the equity investors, and the ROE must reflect them.

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[427] State ex rel. Praxair, Inc. v. PSC, 328 S.W.3d 329, 339 (Mo. App. W.D. 2010).
[428] Federal Power Comm'n v. Conway Corp., 426 U.S. 271, 278 (1976), *quoting* Montana-Dakota Util. Co. v. Northwestern Pub. Serv. Co., 341 U.S. 246, 251 (1951).
[429] In re Revision in Rates Filed by New Jersey Power & Light Co, 89 A.2d 26, 44 (N.J. 1952).
[430] Ex. 7 at 35-50, Bulkley Direct; Ex. 49 at 4-6, Ley Direct.
[431] Ex. 49 at 4-6, Ley Direct; Ex. 52 at 6-10, Ley Surrebuttal.

3. Evergy Missouri Metro's Recommendation: Ms. Bulkley

Ann E. Bulkley presented the Company's ROE recommendation. She is a principal at The Brattle Group, one of the nation's leading energy consulting firms. She holds bachelor's and master's degrees in economics and finance, and has over 30 years of experience consulting to the energy industry. She has previously testified before the Commission on behalf of Evergy and other utilities.[432]

Ms. Bulkley used fourteen proxy companies to estimate the cost of equity for EMM, reducing her original group for two companies that no longer met her screening criteria.[433] This proxy group reflects companies that are substantially comparable to EMM and provides a reasonable basis to estimate the appropriate cost of equity for the Company.[434] With one exception, Staff's proxy group is identical to the Company's group.[435] In stark contrast, the proxy groups of OPC are overly broad and include numerous companies not comparable to Evergy Missouri Metro (e.g., distribution-only electric utilities and transmission-only electric companies), among other flaws.[436]

Ms. Bulkley relied on four methods to estimate the cost of equity: (a) the constant growth Discounted Cash Flow ("DCF") model, (b) the Capital Asset Pricing model ("CAPM"), (c) the empirical CAPM model ("ECAPM"), and (d) a Bond Yield Risk Premium ("BYRP") analysis.[437]

The constant growth DCF model assumes a constant growth rate for earnings and dividends, a stable dividend payout ratio, a constant price-to-earnings ratio, and a discount rate greater than the expected growth rate. Ms. Bulkley testified that it is important to select appropriate

[432] Ex. 7 at 1 & Attach. A, Bulkley Direct.
[433] Ex. 9 at 10, Bulkley Rebuttal.
[434] Ex. 7 at 18, Bulkley Direct.
[435] Ms. Bulkley included PPL Corp. with which Staff's Dr. Won disagreed. He used Duke Energy Corp. instead. See Ex. 120 at 48, Won Direct; Ex. 9 at 16-18, Bulkley Rebuttal.
[436] Ex. 9 at 56, Bulkley Rebuttal.
[437] Ex. 7 at 2, 21, Bulkley Direct.

measures of long-term growth in this DCF model, explaining that she used *projected* earnings-per-share growth rates in order to measure a company's long-term growth.[438] This produced the following results, based on market data through June 30, 2026:[439]

Table 1: Summary of Constant Growth DCF Results

	Minimum	***Average***	***Maximum***
Mean Results	9.98-10.12%	10.86-10.99%	11.72-11.85%
Median Results	9.87-10.03%	10.55-10.70%	11.47-11.60%

Ms. Bulkley also relied on a CAPM analysis which estimated the cost of equity for a company based on a risk-free return plus a premium to compensate investors for the risk of the security. This second component is the product of the market risk premium and the beta coefficient that measures the relative riskiness of the security being evaluated which she explained in detail.[440] The results, as updated through June 30, 2026, suggested an ROE range of 11.07% to 11.44%.[441] Ms. Bulkley also considered the results of the ECAPM model which addressed the tendency of the CAPM to underestimate the cost of equity for companies with low beta coefficients, such as regulated utilities. This produced, as updated, an ROE range of 11.64% to 11.92%.[442]

Finally, Ms. Bulkley utilized a Bond Yield Plus Risk Premium approach which is based on the principle that equity investors require a premium over the return they would have earned as a bond holder. Since equity holders owning stock are subject to returns that are more risky than returns to bond holders, equity investors require a higher return for that additional risk. Ms. Bulkley defined the risk premium as the difference between the authorized ROE and the prevailing

[438] Id. at 23-25.
[439] Ex. 9 at 11, Bulkley Rebuttal.
[440] Ex. 7 at 27-29, Bulkley Direct.
[441] Ex. 9 at 11, Bulkley Rebuttal.
[442] Ex. 7 at 30-31, Bulkley Direct; Ex. 9 at 11, Bulkley Rebuttal.

level of the 30-year Treasury Yield.[443] Utilizing a basic regression analysis, which accounted for high interest rates and authorized ROEs in the 1980s through November 2025, her analysis, as updated through June 30, 2026, estimated the following ROEs:

Table 2: Summary of Bond Yield Plus Risk Premium Results[444]

	Return on Equity
Current 30-Day Average: 30-Year Treasury	10.87%
Near-Term Projected 30-Year Treasury	10.80%
Longer-Term Projected 30-Year Treasury	10.70%

Based upon all of her analyses, Ms. Bulkley recommends that the Commission authorize an ROE of 10.50% based on a range of 10.25% to 11.25%.

4. Staff's Recommendation: Dr. Won

Dr. Won conducted a DCF analysis relying on a two-step DCF model, a CAPM model, and a Bond Yield Plus Risk Premium analysis. While the recommendations that he offers to the Commission are more reasonable than those of OPC's Mr. Murray, there are flaws in Dr. Won's work that required him to ignore their results.

For example, Dr. Won's estimated cost of equity from his two-step DCF analysis of 8.18% is significantly below the average of the authorized ROEs for electric utilities in 2025 which was 9.84% for vertically-integrated electric utilities. Indeed, his estimated cost of equity of 8.18% is well below the lowest authorized ROE for vertically-integrated electric utilities in the United States since at least 1980.[445] A major shortcoming of Dr. Won's DCF analysis is that he failed to rely solely on projected earnings growth rates which are the fundamental driver of dividend growth rates, as numerous experts confirm.[446] Realizing that a DCF result of 8.18% (adjusted to 8.26% in his true-

[443] Ex. 7 at 31-34, Bulkley Direct.
[444] Ex. 9 at 11, Bulkley Rebuttal.
[445] Ex. 9 at 19, Bulkley Rebuttal.
[446] Id. at 22-24; Ex. 10 at 25-26, Bulkley Surrebuttal.

up direct testimony[447]) would not pass muster under the Hope and Bluefield decisions, Dr. Won does not set his ROE recommendation at his DCF result.

Similarly troubling is his CAPM analysis which supports a cost of equity range of 7.97% to 10.34%, with a mean (average) of 9.16%.[448] His CAPM results that rely on the Kroll and Damodaran implied risk premiums (8.39% and 8.41%) are also not reasonable and fail to meet the comparable return standard of Hope/Bluefield as they are well below the low range of comparable authorized returns for any electric utility since 1980, including periods of extremely low long-term interest rates.[449] Ms. Bulkley identified four flaws with the assumptions in Dr. Won's CAPM analysis, including relying on historical data to estimate a forward-looking market return and market risk premium, and an incorrect calculation of the market risk premium.[450] After correcting these errors, Staff's average CAPM results range from 10.0% to 11.22%, all of which demonstrate that the Company's requested ROE of 10.50% is reasonable.[451] Dr. Won does not rely on his CAPM results in making his ROE recommendation.[452]

The basis of Dr. Won's ROE recommendation is his BYRP analysis, given the low results and unreasonable estimates produced by his DCF and CAPM models. In contrast to the wide ranges of his DCF and CAPM results – from 7.11% to 10.34% – Staff's BYRP results yielded an ROE estimate of 9.73% based on a surprisingly narrow range of 9.72% to 9.74%.[453] Ms. Bulkley criticized this analysis, noting that Dr. Won used only a 12-year period (2014-2025) of data when a significantly longer period of utility bond yield and authorized ROE data is available. This data incorporates a much broader set of market conditions and is more appropriate for setting the return

[447] Ex. 165 at 63, Won Surrebuttal/True-Up Direct.
[448] Ex. 120 at 58, Won Direct.
[449] Ex. 9 at 29-30, Bulkley Rebuttal.
[450] Id. at 30.
[451] Ex. 9 at 40-41, Bulkley Rebuttal.
[452] Ex. 120 at 54, 57, Won Direct; Ex. 165 at 63-64, Won Surrebuttal/True-Up Direct.
[453] Ex. 120 at 54-57, Won Direct.

on equity.[454] Moreover, Dr. Won conducted a single regression analysis of the risk premium and bond yield for both A-rated and Baa-rated utility bond yields, even though the Company is currently rated Baa1 by Moody's. When a BYRP analysis using bond yield data from January 1993 to June 2026 (along with quarterly authorized ROEs over that same period) is applied to the current 30-day average of the Baa-rated public utility bond yield, the result of Dr. Won's BYRP analysis is an ROE of 10.40%.[455] This is close to Ms. Bulkley's recommended ROE of 10.50% and at the lower end of her recommended range of 10.25% to 11.25%.

Dr. Won stated in his August 11, 2026 Rebuttal Testimony that data reported by S&P Global Market Intelligence's Regulatory Research Associates showed that "[i]n the first half of 2026, recently authorized comparable ROEs ranged from 9.40% to 11.52%, with an average of 9.85% for all 24 electric utility cases and an average of 9.84% for the 14 vertically integrated electric utility cases."[456] Based on information in the August 2026 report by S&P Global, the average ROE authorized for vertically integrated utilities was 9.86% for the previous 12 months of July 2025 to June 2026.[457]

Given the level of these authorized ROEs, Staff's support for a 9.73% ROE, 13 basis points below the national average is not reasonable, particularly in light of the ongoing upward trend in interest rates between December 2025 and the June 30, 2026, true-up as well as the higher business risk and nuclear risk that the Company faces.

[454] Ex. 9 at 41, Bulkley Rebuttal.
[455] See Ex. 9 at 41-42, Bulkley Rebuttal.
[456] Ex. 145 at 31, Won Rebuttal.
[457] Ex. 165 at 63-64 & Sched. SJW-d17-Updated, Won Surrebuttal/True-Up Direct; S&P Global RRA Regulatory Focus, "Major energy rate case decisions in the US January-June 2026" at 3 (Aug. 2026), attached as **Exhibit A**.

5. OPC's Recommendation: Mr. Murray

Mr. Murray presented only two cost of capital studies: (1) a multi-stage DCF analysis which indicated a cost of equity range of 7.85% to 8.05% (average 8.01%); and (2) a Capital Asset Pricing Model which indicated a cost of equity range of 7.75% to 8.50% (average 7.80%).[458] His ad hoc "rule of thumb" bond risk premium approach "implies" a cost of equity of "approximately 8.75%."[459] None of these results relate to or support his recommended ROE of 9.25% (the mid-point of his narrow range of 9.0% to 9.5%),[460] which he appears to endorse because he recognized the flaws in the studies he conducted.

The reason for this disconnect between his analyses and his recommendation is his position that this Commission and other state utility regulators have authorized ROEs higher than the cost of equity, a position that both Ms. Bulkley and Dr. Won reject.[461] In fact, the majority of Mr. Murray's DCF and CAPM results are substantially lower than any ROE that has been authorized by a regulatory commission in the past. As Ms. Bulkley testified, she is "not aware of any regulatory commission the United States – state or Federal – that has adopted Mr. Murray's position that regulatory commissions have consistently and predictably authorized ROEs that exceed the investor-required return."[462]

OPC's analysis and recommendation should be given no serious consideration, given that they are not based in reality and are either below or at the very low end of the zone of

[458] Ex. 205 at 33, 43, Murray Direct.
[459] Id. at 43.
[460] Id. at 45.
[461] Id. at 26-27; Ex. 9 at 44-45, Bulkley Rebuttal; Ex. 145 at 49-50.
[462] Ex. 9 at 46, Bulkley Rebuttal.

reasonableness recognized by both federal and state appellate courts, as well as this Commission.[463]

6. National ROE Averages and the Recommendations

This Commission has always compared its prospective ROE figures with those of other commissions to make certain that its final decision is not out of the mainstream. Although it does not "unthinkingly mirror the national average," the Commission has concluded that "the national average is an indicator of the capital market" in which a utility "will have to compete for necessary capital."[464] The following chart shows the parties' positions:

Return on Equity: Analysis & Recommendations
Evergy Metro Rate Case, No. ER-2026-0143

	Evergy Metro (Bulkley)	Staff (Won)	OPC (Murray)
Discounted Cash Flow Analysis			
Constant Growth DCF (mean)	10.86-10.99% (avg) 9.98-10.12% (min) 11.72-11.85% (max)	n/a	n/a
Constant Growth DCF (median)	10.55-10.70% (avg) 9.87-10.03% (min) 11.47-11.60% (max)		
Two-Step DCF	n/a	8.26%	n/a
Multi-Stage DCF	n/a	n/a	7.85% - 8.05%
Capital Asset Pricing Model	11.07% - 11.44%	9.08%	7.75% - 8.50%
Empirical CAPM	11.64% - 11.92%	n/a	n/a
Bond Yield Plus Risk Premium	10.70% - 10.87%	9.73%	n/a
Rule of Thumb	n/a	n/a	8.75%
Recommended ROE Range	10.25 - 11.25%	9.48- 9.98%	9.00-9.50%
Recommended ROE	**10.50%**	**9.73%**	**9.25%**

[463] In re Permian Basin Area Rate Cases, 390 U.S. 747, 767 (1968); State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 574 (Mo. App. W.D. 2009); Report and Order at 20-21, In re Kansas City Power & Light Co., No. ER-2006-0314 (2006).
[464] Report and Order at 122, In re Kansas City Power & Light Co., No. ER-2010-0355 (2011).

Dr. Won testified: "In the first half of 2026, recently authorized comparable ROEs ranged from 9.40% to 11.52% … and an average of 9.84% for the 14 vertically integrated electric utility cases."[465] As updated, the average ROE for vertically integrated cases rose to 9.85% for the first half of 2026 and increased to 9.86% for the twelve months ending June 30, 2026.[466] Staff's ROE recommendation of 9.73% is 13 basis points below the national average.

At a minimum, any ROE built on Dr. Won's midpoint must account for two things. The first is the 13 basis point shortfall from the 9.86% national average for vertically integrated utilities. The second is the continued market pressure on the cost of equity since the true-up. Updating Dr. Won's own analyses with market data through August 2026 raises every one of his results.[467] His bond yield plus risk premium analysis, run on the longer data period and the Baa-rated bond yield that Ms. Bulkley identified, produces 10.40%.[468] The record therefore supports no ROE below 9.86%, and when relative business risk and nuclear operating risks are considered, it supports the Company's 10.50% request.

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

The rate of return is calculated from the Company's capital structure, its long-term cost of debt, and its return on equity. As noted above, EMM and Staff agree that the capital structure should reflect 52.19% equity and 47.81% long-term debt, and EMM, Staff, and OPC agree that the cost of long-term debt is 4.54%.

[465] Ex. 145 at 31, Won Rebuttal.
[466] Ex. 165 at 63-64 & Sched. SJW-d17-Updated, Won Surrebuttal/True-Up; S&P Global RRA Regulatory Focus, "Major energy rate case decisions in the US Jan.-June 2026" at 3 (Aug. 2026) (**Exhibit A**).
[467] Ex. 11 at 5, Bulkley True-Up Rebuttal.
[468] Ex. 9 at 41-42, Bulkley Rebuttal.

Based on those figures, and applying the Company's recommendation that the return on equity be set at 10.50% (given Ms. Bulkley's range of 10.25% to 11.25%), the appropriate rate of return is 7.651%.[469]

IV. INCOME TAXES

The Company respectfully requests that the Commission reject the two income tax adjustments OPC proposes, which Staff also opposes. The Partial Stipulation resolves the other income tax sub-issues between the Company and Staff, including a tracker for nuclear production tax credits, and OPC does not oppose it.[470]

15. Income Taxes (EMM: Hardesty; Staff: Young; OPC: Riley)

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

The Commission should find that the income tax expense included in rates should reflect the Partial Stipulation and should not be reduced by OPC's disposition loss deduction, for the reasons discussed under Issue 15.A.i.

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

No. Income tax expense should not be reduced by OPC's normalized disposition loss deduction, which Staff values at $5,437,280 of revenue requirement.[471] Staff witness Matthew Young (Utility Regulatory Audit Supervisor) explained that, for tax purposes, retiring an asset before the end of its tax life produces a loss that reduces taxable income and the associated ADIT

[469] Ex. 53 at 2, Ley True-Up Rebuttal; Ex. 43 at 17 & Sched. RAK-6 (Rev. Reqmt. and Return), Klote Surrebuttal/True-Up Direct.

[470] See Partial Stipulation at 1, 13 & ¶ 11; Ex. 166, Young Surrebuttal/True-Up Direct at 3–4; Ex. 146, Young Rebuttal at 5–6; Ex. 213, Riley Direct at 2; Ex. 216, Riley Surrebuttal at 10; id. at 5.

[471] See Staff Reconciliation at 2, line 149.

is captured and reflected as a reduction to rate base.[472] OPC would reflect a levelized amount of these deductions as an ongoing reduction to income tax expense.[473]

The Disposition Loss Already Reduces Rate Base Through Accumulated Deferred Income Taxes ("ADIT"), and OPC's Adjustment Would Count It Twice

"[R]atepayers already receive a rate base reduction for the disposition loss tax benefits."[474] When an asset is retired, the Company increases its ADIT by the amount of the tax loss.[475] Those benefits are captured in the ADIT offset to rate base, "so the losses are normalized but not ignored."[476] Company witness Melissa Hardesty (Senior Director of Taxes) agrees that the ADIT benefits from these deductions "should be and have been included as a reduction to rate base" in this case.[477]

OPC's adjustment would count the loss twice. Without an offset for deferred income tax, reducing current income tax expense by tax losses would mean "the losses would be double counted in computing income tax expense over time."[478] OPC proposed no offsetting deferred income tax adjustment,[479] and without that deferred tax expense "it would not be appropriate to include the related ADIT tax benefits in rate base."[480] Under OPC's method, ongoing income tax expense would fall, "but rate base would grow over time as ADIT no longer captures the tax benefit."[481]

[472] See Ex. 146, Young Rebuttal at 7.
[473] See Ex. 213, Riley Direct at 9; Ex. 166, Young Surrebuttal/True-Up Direct at 3–4 (Staff opposes the adjustment).
[474] Ex. 166, Young Surrebuttal/True-Up Direct at 4.
[475] See Ex. 146, Young Rebuttal at 7.
[476] Id. at 8.
[477] Ex. 25, Hardesty Rebuttal at 10.
[478] Ex. 25, Hardesty Rebuttal at 9.
[479] Id. at 10.
[480] Id. at 10–11.
[481] Ex. 146, Young Rebuttal at 8.

Disposition Losses Are Timing Differences, and the Rush Island Order Does Not Apply

OPC contends that disposition losses are permanent differences and that Internal Revenue Service ("IRS") rules require the related ADIT to be removed from rate base.[482] However, the write-off of any tax basis for tax purposes "is also just a temporary or timing difference,"[483] since under mass asset accounting, book depreciation deduction will eventually recover the full basis of any asset disposed of, just like the Company has deducted the full tax basis of the asset through tax depreciation, tax basis adjustments, or the tax loss on disposal consistent with the Uniform System of Accounts.[484]

OPC also relies on the Commission's securitization financing order for Ameren Missouri's Rush Island Energy Center.[485] That order addressed a single generating plant being retired early, whose remaining costs were securitized under Section 393.1700.[486] The statute requires those costs to be reduced by the "applicable tax benefits of accumulated and excess deferred income taxes."[487] The order directed that the tax reduction from Rush Island's early-retirement loss be applied against the income taxes included as ongoing financing costs in the securitized charge, until that reduction has been fully applied.[488] OPC's adjustment here would instead build a levelized amount of recurring disposition losses into ongoing income tax expense.[489] The

[482] See Ex. 215, Riley Rebuttal at 4, 5.
[483] Ex. 25, Hardesty Rebuttal at 9.
[484] Id. at 10; 18 C.F.R. Part 101, Electric Plant Instruction 10.B(2), 10.F.
[485] See Ex. 213, Riley Direct at 10.
[486] See Section 393.1700 (Securitized utility tariff bonds, financing order for energy transition costs — definitions — petition, contents, procedure — order issued, contents — requirements — severability clause.).
[487] Section 393.1700.1.(7)(a).
[488] See Ex. 213, Riley Direct at 10 (quoting Amended Report & Order at 78, In re Union Electric Co. d/b/a Ameren Missouri Rush Island Financing Order Petition, No. EF-2024-0021 (Aug. 7, 2024)).
[489] See Ex. 213, Riley Direct at 9. See also Amended Report & Order at 63–64, In re Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant, Nos. EO-2022-0040 & EO-2022-0193 (Sep. 22, 2022) (declining OPC's proposal to apply a $16.5 million tax benefit from the Asbury facility finding that the tax benefit "is a normal timing item that is treated the same as any ADIT item in rates").

simplified method the Company and Staff use to compute income tax expense is also long-standing, in use in establishing rates since the Company's 2014 rate case.[490]

For these reasons, the Commission should find that income tax expense should not be reduced by the tax benefits on a normalized disposition loss deduction.

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

The deferred tax balance related to the Company's net operating losses should remain in rate base. OPC would remove it, which Staff values at $2,941,318 of revenue requirement.[491] Staff opposes the adjustment and would reflect the Company's ADIT balance at June 30, 2026, including the unamortized balance of this item.[492]

OPC contends that a net operating loss carryforward does not change when the tax rate changes, and that the Company has used its carryforwards.[493] Ms. Hardesty agreed with both points.[494] However, neither point decides this issue, because "the tax benefit based on the [net operating loss] carryforward does change when there is a tax rate change."[495] As she testified, the 2017 federal reduction from 35% to 21% and the Missouri reduction from 6% to 4% created deficient deferred income taxes ("DDIT") related to the Company's net operating losses.[496] DDIT is the balance in rate base, and it "has not been fully amortized back to customers."[497] Staff agrees that the balance cannot be used to reduce current or future tax liabilities because it "is a product of changes in tax law instead of an unused tax benefit."[498]

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[490] See Ex. 25, Hardesty Rebuttal at 9, 10; Report & Order at 76-79, In re KCP&L General Rate Increase, No. ER-2014-0370 (Sep. 2, 2015).
[491] See Ex. 216, Riley Surrebuttal at 5; Staff Reconciliation at 2, line 151.
[492] See Ex. 146, Young Rebuttal at 5–6; id. at 6; Ex. 166, Young Surrebuttal/True-Up Direct at 35–36.
[493] See Ex. 213, Riley Direct at 5–6; Ex. 216, Riley Surrebuttal at 2.
[494] See Ex. 25, Hardesty Rebuttal at 12.
[495] Id. at 12.
[496] Id. at 11.
[497] Id. at 12.
[498] Ex. 146, Young Rebuttal at 5–6.

The same tax rate changes also created excess deferred income taxes ("EDIT"), which are amortized back to customers.[499] OPC does not propose to exclude any of the EDIT created by other timing differences, and would exclude only the DDIT related to net operating losses.[500] "The DDIT related to the [net operating losses] should not be treated differently than any other tax deduction or timing difference that created DDIT or EDIT."[501] The net operating losses arose from accelerated tax depreciation,[502] and OPC agrees that the Company's net operating loss "was created by income tax depreciation."[503]

Moreover, this treatment has been in place since the Company's 2018 rate case, which determined the amortization of the DDIT related to net operating losses using the IRS's average rate assumption method.[504] The balances related to the Missouri rate change, including those for net operating losses, were addressed in the Company's 2022 rate case, where the Commission-approved Stipulation provided a four-year amortization.[505] Staff agrees that the effects of the 2017 federal tax law change "were measured and resolved in EMM's 2018 rate case and reflected in the stipulation approved by the Commission,"[506] and that "OPC does not explain why this particular term in the stipulation should be altered."[507]

OPC also contends that including a fictitious deferred tax asset in Evergy Missouri Metro's deferred tax balance in rate base would violate the IRS normalization rules, and it relies on a private

[499] See Ex. 25, Hardesty Rebuttal at 11, 12.
[500] Id. at 12.
[501] Id. at 12.
[502] Id. at 13.
[503] Ex. 213, Riley Direct at 5.
[504] See Order Approving Stipulations & Agreements at ¶ 12, In re EMM General Rate Case, No. ER-2018-0145 (Oct. 31, 2018).
[505] See Ex. 25, Hardesty Rebuttal at 13; Order Approving Four Partial Stipulations & Agreements at 11, In re EMM General Rate Case, No. ER-2022-0129 (Sep. 22, 2022).
[506] Ex. 146, Young Rebuttal at 6.
[507] Id. at 6.

letter ruling to do so.[508] The ruling OPC cites addressed utility property a city condemned, after which the subsidiaries that had owned it held no remaining public utility property and were no longer rate regulated.[509] The facts in the ruling related to non-utility assets is not relevant to whether Evergy Metro's DDIT for NOLs created by depreciation deductions on regulated utility assets should be in rate base. In addition, the ruling "is directed only to the taxpayer requesting it," and it states that it "may not be used or cited as precedent."[510] Also, Mr. Young testified that the balance the NOL deficient ADIT asset offsets the excess ADIT liability and is protected by the IRS normalization rules.[511]

The Commission should find that the net operating loss deferred tax balance reflected in the Company's ADIT at the June 30, 2026, true-up should be included in rate base.

V. FUEL AND PURCHASED POWER

5. Fuel and Purchased Power (EMM: Foo, Meitner; Staff: Niemeier, Nieto, Luebbert adopting Tevie)

The Commission should adopt Staff's fuel and purchased power inputs per the LLPS Stipulation. The LLPS Stipulation resolves Issues 5.A through 5.D for its signatories by adopting Staff's fuel and purchased power modeling, and the FAC base factor in the LLPS Stipulation is built from Staff's true-up fuel run.[512] No other party advances a competing position regarding Issue 5.

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

The Commission should approve Staff's total variable fuel and purchased power cost for this case, as adopted in the LLPS Stipulation, with the Missouri jurisdictional amount as reflected

[508] See Ex. 216, Riley Surrebuttal at 5–6, Sch. JSR-S-03.
[509] See Ex. 216, Riley Surrebuttal, Sch. JSR-S-03 at 4–6, 12.
[510] Id. at 13.
[511] See Ex. 146, Young Rebuttal at 5.
[512] See LLPS Stipulation at ¶¶ 9–10; Tr. Vol. 8 at 66:10–15, 66:20–22 (Meitner).

in Staff's reconciliation.[513] Staff's fuel witness identified no remaining difference between Staff's reconciliation and the Company's position apart from the base factor stated in the LLPS Stipulation.[514] Staff's figure is a total-company amount, and Staff's reconciliation states the lower Missouri jurisdictional amount.[515]

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

The cost of service should include Staff's fuel prices, which the Company has adopted per the LLPS Stipulation.[516] Staff recommends natural gas prices based on a 12-month weighted average ending June 30, 2026, and coal and coal transportation prices based on actual prices for the same 12 months.[517]

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

Staff's normalized market prices, which the Company has adopted per the LLPS Stipulation, should be used to determine the revenue requirement.[518] Staff recommends a normalized ranked average of two-years of shaped prices for the 12 months ending June 30, 2026.[519]

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

The cost of service should include Staff's historical TCR amount, which the Company has adopted per the LLPS Stipulation.[520] Staff recommends a historical twelve-month amount of TCR margin, for the period ending June 30, 2026.[521]

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[513] See LLPS Stipulation at ¶¶ 9-10.
[514] See Tr. Vol. 8 at 75:14–23 (Niemeier).
[515] See Ex. 157, Niemeier Surrebuttal/True-Up Direct at 6; Tr. Vol. 8 at 76:7–16 (Niemeier).
[516] See LLPS Stipulation at ¶¶ 9-10.
[517] See Ex. 158, Nieto Surrebuttal/True-Up Direct at 4; id. at 5; id. at 11; Ex. 113, Nieto Direct at 22–23.
[518] See LLPS Stipulation at ¶¶ 9-10.
[519] See Ex. 164, Tevie Surrebuttal/True-Up Direct at 3; Ex. 119, Tevie Direct at 3–4.
[520] See LLPS Stipulation at ¶ 10.
[521] See Ex. 158, Nieto Surrebuttal/True-Up Direct at 8, 9.

VI. RENEW MISSOURI PROGRAMS AND MEEIA MARGIN RATES

39. Green Button Connect (EMM: McDonald; Staff: Shawn Lange; Renew: Wyszkowski; OPC: Marke)

The Commission should approve the Programs Stipulation, which resolves Issues 39.A. through 39.D.[522] OPC objected to the Programs Stipulation only on Issue 16.E, while Google, MECG, and Velvet Tech did not oppose it.[523]

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

Yes. The Programs Stipulation requires the Company to implement GBC no later than December 31, 2028.[524] The Company's GBC solution will comply with all Green Button standards, be available to all customer classes, provide convenient and secure customer authorization that follows Green Button Connect best practices, and carry annual certification by the Green Button Alliance.[525]

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

No. The Commission should approve the GBC terms in the Programs Stipulation, which contains no GBC tariff, in place of the tariff Renew Missouri proposed.[526]

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

No. The Programs Stipulation allows the Company to defer GBC set-up, implementation, and licensing costs for consideration in its next general rate case.[527]

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[522] See Programs Stipulation at 1-3.
[523] Id. at ¶¶ 17–18.
[524] Id. at ¶ 6.
[525] Id.
[526] Id. at ¶¶ 3, 6, 12.
[527] Id. at ¶ 6.

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?

No. The Programs Stipulation includes no funding for a regional data hub study.[528]

40. Customer Battery Programs (EMM: Lutz; Staff: Shawn Lange; Renew: Fracica; OPC: Marke)

The Commission should approve the Programs Stipulation, which resolves Issue 40.A.[529]

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

No. The Programs Stipulation provides that no battery pilot will be implemented as part of this proceeding.[530] The signatories will instead convene a stakeholder meeting on or before the fourth quarter of 2027 to discuss the potential development of a battery storage program.[531] Before that meeting, the Company will produce the results of customer engagement surveys on interest in a battery partnership program, along with lists of its worst performing circuits and of the circuits or areas prone to outages, experiencing transformer overloading or failure, experiencing growth or planned development, or requiring grid hardening or transmission investment not yet scheduled.[532]

[528] Id. at ¶¶ 5–6, 12.
[529] See Programs Stipulation at ¶ 7; id. at 4.
[530] Id. at ¶ 7.
[531] Id.
[532] Id.

41. Income-Eligible Solar Program (EMM: Lutz; Staff took no position; Renew: Fracica; OPC: Marke)

The Commission should approve the Programs Stipulation, which resolves Issue 41.A.[533]

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

No. The Programs Stipulation provides that the Company will continue operating its existing Income-Eligible Solar Subscription Pilot under its approved terms and complete the evaluations as expected.[534]

42. MEEIA Margin Rates (EMM: Jaynes; Staff: H. Poudel)

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

The net margin rates should be calculated using the method the Company used for Schedule GAJ-12 to Mr. Jaynes's direct testimony. That method should be applied to the rates and billing determinants approved in this case. The Company's Demand Side Investment Mechanism Rider calculates the throughput disincentive by multiplying the programs' monthly kWh savings by the net margin rates and a net-to-gross factor.[535] Schedule GAJ-12 calculates net margin rates on the Company's proposed rates.[536] Net margin rates have traditionally been updated at the end of a case, once final rates are determined.[537]

Staff does not oppose the Company's methodology, and its Statement of Positions states that the net margin rates should be recalculated on the final rates in this case using that methodology.[538] The Company's tariff requires it to "file an update to [net margin revenue] rates

[533] See Programs Stipulation at ¶ 8; id. at 5.
[534] Id. at ¶ 8.
[535] See P.S.C. MO. No. 7, Original Sheet Nos. 49.4–49.5.
[536] See Ex. 33, Jaynes Direct at 53, Sch. GAJ-12.
[537] Id. at 53.
[538] See Staff Positions at 39.

by month by rate class/rate plan contemporaneous with filing any compliance tariff sheets in any general rate case reflecting the rates set in that case, and the billing determinants used in setting rates in that case."[539]

For these reasons, the Commission's Report and Order should direct that the Company's MEEIA net margin rates be calculated using the Schedule GAJ-12 method, applied to the rates and billing determinants approved in this case. The Report and Order should also require the Company to update and file those rates with its compliance tariff sheets.

VII. PISA

18. Plant in Service Accounting (EMM: Kramer; Staff: Young; OPC: Alvarez, Shapley)

The Company respectfully requests that the Commission include in rate base the plant in service accounting deferral balance in Exhibit B to the Partial Stipulation. OPC's proposed reductions depend on the distribution and transmission disallowances that evidence shows should be rejected by the Commission as addressed in Section VIII.

B. What amount of PISA deferral should be reflected in rate base?

OPC's only objection to the PISA deferral is a reduction to remove the distribution and transmission projects it requests the Commission disallow, and Section VIII explains why the Commission should reject those disallowances.[540] Apart from those projects, the PISA deferral reflected in rate base should be the balance in Exhibit B to the Partial Stipulation.

Section 393.1400 requires the Company to defer to a regulatory asset 85 percent of the depreciation expense and return on qualifying electric plant, and it requires the balance of that regulatory asset to be included in rate base in each general rate case "without any offset, reduction,

[539] See P.S.C. MO. No. 7, Original Sheet No. 49.4.
[540] See OPC Positions at 8.

or adjustment based upon consideration of any other factor," subject only to the statutory cap.[541] The one permitted adjustment is "to reflect any prudence disallowances ordered by the commission."[542] Exhibit B to the Partial Stipulation schedules the Company's regulatory assets and liabilities, and Staff's position on Issue 18.B is reflected in that schedule.[543]

The Partial Stipulation, which OPC does not oppose, already provides that "[a]ny plant disallowances identified by OPC witnesses and ordered by the Commission will have appropriate adjustments to remove PISA deferrals."[544] A disallowance the Commission does not order cannot reduce the PISA balance, because Section 393.1400 permits an adjustment only for a prudence disallowance the Commission has ordered. Because the Commission should reject OPC's distribution and transmission disallowances for the reasons stated in Section VIII, no adjustment to the Exhibit B balance is warranted.

The Commission should approve the PISA deferral reflected in Exhibit B to the Partial Stipulation.

VIII. RATEBASE AND ASSET MANAGEMENT

The Company respectfully requests that the Commission include CWIP for Mullin Creek No. 2 in rate base at the overall rate of return, as the statute permits. The Commission should also reject Staff's retired plant adjustment and OPC's proposed transmission and distribution disallowances.

[541] See Section 393.1400.2(1).
[542] Section 393.1400.2(2).
[543] See Partial Stipulation at 3 & Ex. B; Tr. Vol. 8 at 102:23–103:11 (Staff counsel).
[544] Partial Stipulation at ¶ 7; id. at 1.

20. Rate Base Components

B. What amount of construction work in progress is appropriate to reflect in rate base? (EMM: Gunn, Klote; Staff: Young; OPC: Marke; Riley)

The Commission should include $64,389,129 of CWIP for Mullin Creek No. 2 in rate base, prior to, in conjunction with, or conditioned upon its determination of the CWIP amount in the Company's CCN proceeding, Case No. EA-2026-0154. [545]

Section 393.135.2(1) provides that an electrical corporation "may be permitted," subject to a refund, to include CWIP "for any new natural gas-generating unit in rate base," in lieu of the allowance for funds used during construction ("AFUDC") that would otherwise accrue after the new base rates take effect.[546] The statute reserves the amount of CWIP to the CCN proceeding, and the Commission has the discretion to sequence the two cases so that rates from this case reflect that amount. OPC's remaining objections add conditions the statute does not contain.

Section 393.135.2(1) Permits CWIP for Mullin Creek No. 2 and Protects Customers

Staff witness Matthew Young (Utility Regulatory Audit Supervisor) agrees that Section 393.135 "was revised in 2025 to make an exception for rate base treatment of CWIP for any new natural gas-generating unit."[547] The Company's CWIP balance for Mullin Creek No. 2 at the June 30, 2026 true-up is $64,389,129,[548] "an early-stage amount" of a multi-year project that is "far below the anticipated project budget."[549] Including that balance in rate base "reduces the amount of interest that would otherwise accrue during construction and helps moderate the rate impact to customers once the facility is placed into service."[550] Excluding it would not spare customers those

[545] In re Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro for Permission and Approval of a Certificate of Convenience and Necessity Authorizing It to Construct, Install, Own, Operate, Manage, Maintain, and Control a Natural Gas Electrical Production Facility, No. EA-2026-0154 (application filed May 14, 2026).
[546] Section 393.135.2(1).
[547] Ex. 121, Young Direct at 39.
[548] See Ex. 43, Klote Surrebuttal/True-Up Direct, Sch. RAK-7.
[549] Ex. 42, Klote Rebuttal at 9.
[550] Ex. 41, Klote Direct at 15.

costs, because Staff agrees that the Company "will still charge the project with the full amount of its actual carrying costs and recover it from customers over the life of the constructed asset,"[551] and AFUDC continues to accrue on the project while recovery is delayed.[552]

The statute also protects customers, as OPC's own witness describes: CWIP "is limited to new natural gas units, bound by the estimated cost and construction timeline of the project, and includes refund provisions (with interest) if the project incurs imprudent costs, is not finished, or is not finished in a reasonable timeframe."[553] Those refund provisions preserve the review Staff seeks. Staff's concern is the support the Company provided for the charges in discovery and in its affiliate transactions report,[554] and if the Commission later determines in a complaint or general rate proceeding that construction costs were imprudently incurred, the recoveries are refunded with interest.[555]

The CCN Case Determines the Amount, and the Commission May Decide It Prior to, in Conjunction with, or as a Condition of This Case

Staff's position is that the statutes "require the Commission to establish limitations in a CCN case before it can include CWIP in base rates."[556] Chair Hahn asked Company witness Kevin Gunn what the statute requires in each proceeding. He answered that the amount is determined in the CCN case, so the only question is timing.[557] The statute provides that the Commission "shall determine, in a proceeding under section 393.170, the amount of construction work in progress that may be included in rate base,"[558] and "[i]t is well within the Commission's discretion to

[551] Ex. 166, Young Surrebuttal/True-Up Direct at 6; see also Tr. Vol. 9 at 105:24–106:3 (Young).
[552] See Ex. 22, Gunn Rebuttal at 21.
[553] Ex. 202, Marke Direct at 36.
[554] See Ex. 175, Young True-Up Rebuttal at 4.
[555] See Section 393.135.2(1).
[556] Staff Positions at 16.
[557] See Tr. Vol. 9 at 96:5–8 (Gunn).
[558] Section 393.135.2(1).

coordinate the inclusion of CWIP for Mullin Creek #2 in this rate case."[559] The CCN case is pending: the Company's application requests that the Commission determine the amount of CWIP to be included in rate base, and it requests a decision by December 23, 2026,[560] while the Company's tariffs in this case are suspended until January 6, 2027.[561] The Commission can therefore decide the CCN case prior to its order here, decide the two cases in conjunction with each other, or condition the CWIP in rate base upon its findings in the CCN case, and each option can be completed before rates take effect.[562] The Company's preference is that the Commission decide the CCN case first and then include the CWIP in rate base here. Including CWIP here "does not limit or diminish the Commission's authority in the pending CCN proceeding."[563] The Company incorporates the CCN case into this brief by reference in its entirety, including the evidence, the parties' statements of positions, the Non-Unanimous Stipulation and Agreement, and the briefs.[564] The Commission may take official notice of its own records in that case, and the Company requests that it do so.[565]

OPC's Objections Add Conditions the Statute Does Not Contain

OPC's first ground is the same as Staff's and fails for the same reason.[566] OPC's second ground is that the turbine prepayments "are not encompassed by the definition of CWIP,"[567] because the Company described the fees as "preliminary, pre-construction costs."[568] The phrase

[559] Ex. 22, Gunn Rebuttal at 19.
[560] See Ex. 121, Young Direct at 40; id. at 40–41.
[561] See Order Suspending Tariff, Giving Notice of Contested Case Status, Delegating Authority, and Scheduling Evidentiary Hearing at 2 (Feb. 19, 2026).
[562] See Tr. Vol. 9 at 96:8–97:7 (Gunn).
[563] Ex. 42, Klote Rebuttal at 10.
[564] Non-Unanimous Stipulation and Agreement, No. EA-2026-0154 (Oct. 2, 2026).
[565] See Section 536.070(6); Environmental Utilities, LLC v. Public Service Commission, 219 S.W.3d 256, 265 (Mo. App. W.D. 2007) (Commission "took proper administrative notice" of its findings in another case; "[c]ourts may take judicial notice of other proceedings when the cases are interwoven or interdependent").
[566] See OPC Positions at 8.
[567] Ex. 216, Riley Surrebuttal at 10; id. at 10–11.
[568] See Ex. 216, Riley Surrebuttal, Sch. JSR-S-04 (Robinett Direct at 9); Ex. 41, Klote Direct at 14–15.

described "the timing of those costs relative to physical construction activity," and the fees are "part of the cost path necessary to develop and construct the new gas-generation resource."[569] OPC itself agrees that the payments were needed: "No one is claiming this is imprudent. It is a necessary requirement to ensure this project is completed in the timeframe that EMM has presented in its CCN filing."[570] The statute limits CWIP to the estimated cost of the project and to "[p]roject expenditures made within the estimated construction period for such project," limits the Commission applies when it determines the amount in the CCN case.[571] "The fact that an invoice or payment occurs before visible field construction does not make it unrelated to the construction project," and because the statute substitutes CWIP for AFUDC, excluding AFUDC-eligible costs from CWIP "would create an illogical inconsistency."[572] Without CWIP, the turbine reservation fees would be in plant in service when Mullin Creek No. 2 goes into service.[573]

OPC's third ground is that CWIP should be opposed unless "customers taking service under the LLPS tariff explicitly agree that they will bear all associated costs."[574] The statute contains no such condition. Chair Hahn also asked Mr. Gunn whether any part of Mullin Creek No. 2 would serve large users and whether its cost allocation had been determined.[575] She raised the allocation question again at the hearing in the CCN case.[576] Allocation of CWIP revenue responsibility among the customer classes is Issue 32.D, and Section X answers her question there. The Company's study allocates none of the CWIP to Schedule LLPS, even though Schedule LLPS

[569] Ex. 42, Klote Rebuttal at 6.
[570] Ex. 216, Riley Surrebuttal at 11.
[571] Section 393.135.2(1)(b).
[572] Ex. 42, Klote Rebuttal at 7–8.
[573] See Tr. Vol. 9 at 93:5–94:2 (Klote).
[574] Ex. 202, Marke Direct at 42; see Ex. 204, Marke Surrebuttal at 11.
[575] See Tr. Vol. 9 at 97:13–21 (Gunn).
[576] See Tr. Vol. 3 at 18:21–20:18 (Chair Hahn), No. EA-2026-0154 (Oct. 21, 2026) (EFIS Item 75), of which the Company requests official notice as stated above. That volume, like Volume 7 here, prints no page or line numbers, and the citation gives the page of the filed document and the line counted from the top of that page.

customers pay a share of it through the Large Power Service class percentage in the Rate Design Settlement.[577] Mullin Creek No. 2 is in any event a system resource designed to meet organic load growth, system growth, and increases in SPP's planning reserve margins, and a resource of this type appeared in the Company's integrated resource plan as early as 2024.[578] As Staff acknowledges, the Company's data request responses describe its contemplation of generation at the Mullin Creek location as far back as 2023.[579]

The Commission should include the Company's $64,389,129 CWIP balance for Mullin Creek No. 2 in rate base, prior to, in conjunction with, or conditioned upon its determination of the CWIP amount in Case No. EA-2026-0154.

C. How much of EMM's current rate base has been retired, and should a rate of return be applied to this amount? (EMM: Ives, Klote, Mulvany, Spanos; Staff: Young)

The Commission should reject Staff's retired plant adjustment and apply the overall rate of return to the Company's rate base without it. Staff states that, since the Company's prior rate case, approximately $50 million of net rate base represents plant that has been retired, and Staff would remove that amount from the rate of return calculation while continuing to depreciate the retired assets.[580] Staff acknowledges that a direct adjustment of this kind "may be new."[581] The adjustment fails because a retirement under mass asset accounting leaves net rate base unchanged, because retirement experience is addressed through depreciation rates that Staff did not change, and because Staff's PISA theory does not explain why any asset was retired.

[577] See Ex. 33, Jaynes Direct at 40; Rate Design Settlement at ¶ 2.
[578] See Tr. Vol. 9 at 97:13–21, 99:21–100:4 (Gunn); Ex. 22, Gunn Rebuttal at 22–24.
[579] See Ex. 175, Young True-Up Rebuttal at 2–3.
[580] See Ex. 166, Young Surrebuttal/True-Up Direct at 9, 19.
[581] Id. at 13.

Under Mass Asset Accounting, a Retirement Leaves Net Rate Base Unchanged

The Commission's rules require the Company to keep its accounts in conformity with the Uniform System of Accounts.[582] Under those rules, when a retirement unit is retired, "the book cost thereof shall be credited to the electric plant account," and for depreciable property that book cost "shall be charged to the accumulated provision for depreciation applicable to such property."[583] A majority of the Company's rate base "is subject to mass asset accounting," and a retirement "leaves net rate base unchanged regardless of how long the asset has actually been in-service and regardless of how much Reserve had been accumulated."[584] The Company depreciates each account as a whole, and plant and reserve are reduced by equal amounts when an asset retires.[585] The Company applies mass asset accounting because of the volume of its assets, and the depreciation studies required every five years examine the relationship between gross plant and the reserve balance.[586] What remains in rate base after a retirement is the net investment in the account.[587] Staff's own testimony conditions rate base treatment on that accounting, because Staff agrees that "as long as the fundamentals of mass asset accounting are intact, using rate base in the calculation is appropriate."[588]

Retirement Experience Belongs in Depreciation Rates, Which Staff Did Not Change

Group depreciation expects some units in an account to retire before the average life and others after it, because each account's survivor curve "reflects retirements that will occur before the average service life and after the average service life."[589] Staff agrees that "there are also assets

[582] See 20 CSR 4240-20.030(1).
[583] Amended Report & Order at 31–32, In re Evergy Missouri Metro Rate Increase and Evergy Missouri West Rate Increase, Nos. ER-2022-0129 and ER-2022-0130 (Dec. 8, 2022) (quoting Electric Plant Instruction 10.B(2)).
[584] Ex. 121, Young Direct at 34, 35.
[585] See Tr. Vol. 9 at 121:8–122:15 (Young).
[586] See Tr. Vol. 9 at 129:16–130:19 (Klote).
[587] See 18 C.F.R. pt. 101, Electric Plant Instruction 10.B(2); 20 CSR 4240-20.030(1).
[588] Ex. 121, Young Direct at 38.
[589] Ex. 80, Spanos Rebuttal at 24.

that live beyond the assumed book life. If the depreciation rate reflects the average life of a group of assets, the actual life of each individual retired asset can be ignored."[590] An average accounting life of assets "is not an operating instruction."[591] Retirement experience is therefore addressed through depreciation rates, so "[t]he relevant question therefore becomes whether the approved service lives and depreciation assumptions accurately reflect actual retirement behavior. That is fundamentally a depreciation question."[592]

Staff's depreciation witness, Amanda Arandia, answered that question in this case, because her depreciation rates are "designed to recover the remaining unrecovered investment over the remaining service life of each account."[593] In each account where Staff proposed a different survivor curve, Staff's average service life was equal to or longer than the Company's.[594] Staff did not change any depreciation rate or survivor curve based on its retired plant adjustment.[595] The Partial Stipulation adopts depreciation rates based on Staff's true-up model, subject to MECG's challenge under Issue 17.A, which Section XII addresses.[596]

Staff's Adjustment Applies a Unit Measure to Group Accounts and Creates a Second Depreciation Mechanism

Staff's position is that a return on retired plant is inequitable.[597] The return at issue, however, is earned on net investment in accounts whose replacement plant is in service, and Staff does not challenge the prudence of any replacement.[598] The Regulatory Law Judge asked Staff's witness whether the adjustment has any impact on the value of the Company's completed projects

[590] Ex. 121, Young Direct at 35.
[591] Ex. 30, Ives Rebuttal at 15.
[592] Ex. 42, Klote Rebuttal at 19.
[593] Ex. 100, Arandia Direct at 4–5.
[594] See Ex. 80, Spanos Rebuttal at 3–4, Fig. 1.
[595] See Tr. Vol. 9 at 124:3–7 (Young).
[596] See Partial Stipulation at 1 & ¶ 12.
[597] See Ex. 166, Young Surrebuttal/True-Up Direct at 9.
[598] Id. at 10.

included in rate base. He answered that it does not, regardless of PISA treatment.[599] Staff's adjustment instead applies a unit measure to retired units while leaving group accounting in place for everything else. For each retired mass asset, Staff "measured the amount of undepreciated original cost of the asset."[600] Staff removes that amount from the return calculation while group depreciation continues for the same assets.[601] Staff thus "effectively creates a second depreciation mechanism outside the depreciation process," which "produces a separation between return of investment and return on investment."[602]

Staff relies on the Commission's decision on Evergy Missouri West's Sibley plant and on orders of other commissions.[603] Each case Staff cites concerns a generating plant or unit retired with an undepreciated balance. In the Sibley case the Commission found that, "[u]nder the life span method, the generating units should not be looked at as a fleet but as individual units with individual lives, not as (or similar to) a mass asset," and it rested its denial of a return on Sibley's undepreciated balance on "a determination that as retired plant Sibley should be removed from Evergy's books."[604] Here, by contrast, Staff does not propose removing the retired assets from the Company's books.

Staff's PISA Theory Does Not Support the Adjustment

Staff contends that "an imbalance in retirements has occurred."[605] Staff attributes that imbalance to PISA.[606] Staff now says that "a decision on PISA's contribution to EMM's capital

[599] See Tr. Vol. 9 at 115:4–10 (Young).
[600] Ex. 121, Young Direct at 36.
[601] See Tr. Vol. 9 at 122:16–124:13 (Young).
[602] Ex. 42, Klote Rebuttal at 19, 20 (emphasis added).
[603] See Ex. 166, Young Surrebuttal/True-Up Direct at 13–15.
[604] Amended Report & Order at 23–24, 40, In re Evergy Missouri Metro Rate Increase and Evergy Missouri West Rate Increase, Nos. ER-2022-0129 and ER-2022-0130 (Dec. 8, 2022).
[605] Ex. 121, Young Direct at 38.
[606] Id. at 37.

spending is not needed to set just and reasonable rates."[607] Staff also concedes that its PISA measurement "contained formula errors."[608] Staff's comparison of plant growth before and after PISA does not identify the reason any specific asset was retired.[609] Staff's statement that many PISA projects replace existing plant is an inference from timing and statutory purpose, because Staff made no project-by-project finding, did not test whether inflation increased the plant balance after 2019, did not isolate changes in labor, material, or equipment costs from changes in the amount of work performed, did not isolate aging infrastructure, reliability needs, resiliency needs, or equipment availability from PISA, and extended its analysis only to the past four years of retirements.[610] Staff's own testimony instead attributes the retirements to system condition, because the Company's "grid modernization efforts are driven by the condition of its system and not the remaining book life of its assets but the PISA statute allows for more aggressive modernization by alleviating regulatory lag."[611] The PISA statute itself refers to "retirements of plant replaced by such qualifying electric plant" in computing the deferral.[612] In any event, PISA does not accelerate asset retirements. The Regulatory Law Judge put that question to the Company's depreciation witness, John J. Spanos, and he answered, "No."[613] Assets are retired according to their survivor curves.[614]

[607] Ex. 166, Young Surrebuttal/True-Up Direct at 19.
[608] Id. at 17.
[609] See Tr. Vol. 9 at 119:13–120:23 (Young).
[610] See Tr. Vol. 9 at 120:24–121:7, 124:3–7 (Young).
[611] Ex. 121, Young Direct at 37.
[612] Section 393.1400.3(1).
[613] See Tr. Vol. 11 at 24:14–25:1, 26:1–5 (Spanos).
[614] See id.; Ex. 80, Spanos Rebuttal at 23–24.

Staff corrected the calculation errors the Company identified. The Company identified an incorrect depreciation rate on 135 line items in Staff's direct analysis.[615] Staff corrected those rates at true-up.[616] The correction does not change the Company's position on mass asset accounting.[617]

The Commission should reject Staff's retired plant adjustment. Staff proposed no change to any depreciation rate or survivor curve, yet its adjustment removes approximately $50 million from the rate of return calculation while leaving the same investment in net plant subject to depreciation.

E. If construction work in progress is included in rate base, what rate of return should be applied to it? (EMM: Ley; Staff: Young; OPC: Murray)

If CWIP is included in rate base, it should earn the overall rate of return the Commission sets under Issue 1, which Section III addresses. Staff agrees that CWIP in rate base "should be subject to the overall rate of return ordered by the Commission."[618] OPC instead proposes a return of 5.08 percent on CWIP, specifically "to achieve a net present value of zero."[619] The statute provides for no separate return on CWIP, and OPC's figure rests on a discounting method that counts the Company's cost of capital twice.

The Statute Provides for CWIP in Rate Base at the Overall Rate of Return

The statute provides for CWIP "in rate base," makes it a substitute for AFUDC, and provides for no separate return.[620] Indeed, "nothing in the statute suggests that CWIP included in rate base should be assigned a separate, reduced rate of return."[621] Staff's cost of capital witness, Dr. Seoung Joun Won (Regulatory Compliance Manager, Financial Analysis Department), agrees

[615] See Ex. 42, Klote Rebuttal at 15–16.
[616] See Tr. Vol. 9 at 133:9–15 (Klote); Tr. Vol. 9 at 116:1–13 (Young).
[617] See Tr. Vol. 9 at 133:18–134:16 (Klote).
[618] Staff Positions at 17.
[619] See OPC Positions at 9.
[620] See Section 393.135.2(1); see also Ex. 53, Ley True-Up Rebuttal at 7.
[621] Ex. 53, Ley True-Up Rebuttal at 7.

that "[n]either interim short-term debt financing nor CWIP in rate base, by itself, justifies an authorized ROR below the utility's overall cost of capital," because construction "still carries underlying business and corporate risk that debt holders do not bear alone; equity capital remains exposed to that risk." The return on CWIP therefore "should reflect the utility's actual cost of capital, rather than diluted short-term financing proxies."[622]

OPC's 5.08 Percent Return Is an Asset-Specific Rate the Statute Does Not Provide

OPC's 5.08 percent return, compared with continued AFUDC, "currently approximates a NPV of $0."[623] OPC's figure depends on discounting customer costs at the Company's weighted average cost of capital.[624] That cost of capital, however, "is already reflected in both the revenue requirements with AFUDC and the revenue requirements with CWIP recovery."[625] On a nominal basis, OPC acknowledges that the Company determined "its Missouri retail customers would save $95.8 million."[626]

OPC also acknowledges that "it is not a typical step in developing the revenue requirement to apply a distinct ROR to a particular rate base asset apart from all the assets in rate base."[627] OPC's recommendation then shifts within the same testimony, which recommends 5.08 percent and, a page later, recommends that the "second alternative ROR ('FERC USOA method')" be applied if CWIP is allowed in rate base.[628] The capital structure OPC proposes for CWIP "does not comport with established regulatory ratemaking principles."[629] Indeed, asked by the

[622] Ex. 174, Won True-Up Rebuttal at 4, 5.
[623] Ex. 207, Murray Surrebuttal/True-Up Direct at 7.
[624] Id. at 4–5, 7; Ex. 53, Ley True-Up Rebuttal at 3.
[625] Ex. 53, Ley True-Up Rebuttal at 3.
[626] Ex. 207, Murray Surrebuttal/True-Up Direct at 6.
[627] Id. at 7.
[628] Id. at 7, 8.
[629] Ex. 174, Won True-Up Rebuttal at 3.

Regulatory Law Judge whether other commissions have approved a separate return on CWIP, OPC's witness could not name a single example.[630]

The Commission should apply the overall rate of return it sets in this case to any CWIP included in rate base and reject OPC's proposed 5.08 percent return and alternative capital structure for CWIP.

F. What amount of transmission investment since EMM's last rate case should be included in rate base? (EMM: Rietcheck, Ives; Staff took no position ; OPC: Alvarez; Shapley)

The Commission should include in rate base the Company's transmission investment since its last rate case, without OPC's proposed disallowances. OPC's witnesses propose disallowing $73.1 million of transmission projects and, separately, the $14.7 million that is the subject of Issue 20.H.[631] The $73.1 million covers four projects: the Wolf Creek station power system modernization, the Leeds–Winchester and Brunswick–Carrollton transmission-line rebuilds, and the Claycomo modernization project.[632] The prudence standard governs each project, not the after-the-fact benefit-cost test OPC proposes, and each project rested on documented condition.

The Prudence Standard, Not OPC's After-the-Fact Benefit-Cost Test, Governs

A utility's costs are presumed prudent. When another party "creates a serious doubt as to the prudence of an expenditure," the utility must dispel it, and the utility's conduct is judged by "whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight." In its prudence reviews, the Commission has held that a disallowance also requires a finding "that such

[630] See Tr. Vol. 9 at 143:9–24 (Murray).
[631] See Ex. 221, Shapley Surrebuttal at 34; Ex. 201, Alvarez Surrebuttal at 2.
[632] See Ex. 221, Shapley Surrebuttal at 28–34; Ex. 89(C)/90(P), Rietcheck Sur-Surrebuttal at 3.

imprudence resulted in harm to the utility's ratepayers."[633] OPC's witness agrees that "hindsight should not be used to determine the prudence of any individual project."[634] The PISA statute leaves these burdens unchanged.[635]

OPC nevertheless requests that the Commission apply a new test after the fact. OPC witness David Shapley (Wired Group) contends that the used-and-useful standard "is inadequate" for discretionary replacement of equipment that passed objective inspections and tests, so that "a different standard is needed," under which "the value delivered to customers from such replacements must exceed the cost to customers of such replacements."[636] OPC witness Paul Alvarez (Wired Group) would also require risk-informed benefit-cost analysis for capital projects going forward.[637] No such test existed when these investments were made, and "this Commission has not adopted a single standard to apply."[638] A rule adopted now cannot measure decisions made before it existed.

Each Transmission Project Rested on Documented Condition

Company witness Andrew Rietcheck (Senior Director of Large Construction and Substation Maintenance, Evergy Kansas Central, Inc.) documented the condition behind each of the four projects.[639] At Wolf Creek, the project was "a comprehensive modernization of the station power system rather than a one-for-one replacement of Transformer 7," because evaluations indicated that Transformers 4, 5, and 6 "exhibited age-related degradation and gassing concerns

[633] Report & Order at 12, In re Eleventh Prudence Review of Evergy Missouri West FAC Costs, No. EO-2023-0277 (Aug. 7, 2024) (citing State ex rel. Associated Natural Gas Co. v. Public Service Commission, 954 S.W.2d 520, 529–30 (Mo. App. W.D. 1997)).
[634] Ex. 201, Alvarez Surrebuttal at 6.
[635] See Section 393.1400.2(2).
[636] Ex. 220, Shapley Direct at 24.
[637] See Ex. 200, Alvarez Direct at 20–21.
[638] Ex. 32, Ives True-Up Rebuttal at 8.
[639] Ex. 89(C)/90(P), Rietcheck Sur-Surrebuttal at 6–18.

similar to those identified on TX-7."[640] Wolf Creek, as a nuclear generating facility, "cannot utilize a run-to-failure maintenance strategy for equipment supporting nuclear safety-related and risk-significant functions," and replacing the units one at a time would have required multiple refueling outages.[641] The Leeds–Winchester poles averaged more than 45 years of age, most of the Brunswick–Carrollton poles were placed in service in 1953, older than all but one percent of the Company's transmission poles, the 2018 intrusive inspection of the Brunswick–Carrollton line rejected 20 structures beyond those found in annual visual inspections, and "widespread broken conductor strands" led the Company to cancel structure replacements for safety.[642] The Claycomo transformers were "approximately 36 to 57 years old" and showed gassing and other condition concerns.[643]

OPC's contrary assessment rests on the Company's data request responses, because OPC evaluated the projects without visiting them.[644] Even on that review, OPC could not identify a project that produced no consumer benefit.[645] Remaining net book value does not establish that a replacement was imprudent, because the prudence inquiry "must consider the information reasonably available when the Company made its decision."[646]

The Commission should include the Company's transmission investment since its last rate case in rate base and reject OPC's proposed disallowance of $73.1 million.

[640] Id. 6.
[641] Id. at 7.
[642] Id. at 13, 14–15.
[643] Id. at 16–17.
[644] See Tr. Vol. 10 at 24:14–23 (Shapley).
[645] See Tr. Vol. 10 at 28:13–18 (Shapley).
[646] Ex. 89(C)/90(P), Rietcheck Sur-Surrebuttal at 18; id. at 11.

H. Should rate base be reduced to remove Evergy Kansas Central's investment in transmission to serve Panasonic allocated to EMM? (EMM: Rueter; Staff took no position; OPC: Alvarez; Shapley)

No. Rate base should not be reduced for the transmission facilities associated with the Panasonic delivery point. OPC contends that Evergy Kansas Central "collected no Contributions In Aid of Construction (CIAC) from Panasonic" for transmission facilities, and its witness objects that "[i]t does not seem fair to me that decisions made by Evergy Kansas Central and the Kansas Corporation Commission should increase EMM's rate base and Missouri customer rates."[647] OPC would therefore remove $14.7 million from rate base.[648] The facilities are SPP base plan upgrades whose costs SPP allocates on a load-ratio share, Panasonic reimbursed the facilities directly assigned to it, and OPC identifies no imprudent decision by the Company.

The Panasonic Facilities Are SPP Base Plan Upgrades Recovered on a Load-Ratio Share, and Panasonic Reimbursed the Directly Assigned Facilities

Panasonic "reimbursed Evergy for the actual distribution costs, including some costs at the transmission voltage, through a one-time payment completed at the end of 2025."[649] For the transmission upgrades, "SPP issued Notifications to Construct for the applicable Base Plan transmission upgrades." The transmission owner, here Evergy Kansas Central, initially funds construction, and SPP then recovers the annual revenue requirement from transmission customers under Schedule 11 of its tariff on a load-ratio-share basis.[650] The Company "bears only the portion of the resulting Schedule 11 revenue requirement allocated to it through SPP's load-ratio-share methodology." For the West Gardner–Craig 345 kV project, the 2026 Schedule 11 amount is about $3.4 million, "of which Metro is only responsible for their load ratio share of about 6.86%."[651]

[647] Id. at 2.
[648] Id.
[649] Ex. 87(C)/88(P), Reuter Sur-Surrebuttal at 2–3.
[650] Id. at 3.
[651] Id. at 4.

OPC Identifies No Imprudent Decision, and Its Witness's Admissions Undercut the $14.7 Million Disallowance

OPC's testimony "does not suggest the company should not have constructed" the facilities.[652] The Company's data request response shows that an Evergy utility was asked to construct them. OPC's witness understood SPP to have made the request, acknowledged limited familiarity with how the costs of Notifications to Construct are allocated, and could not define Base Plan funding.[653] OPC performed no prudence review of any specifically identified transmission project.[654] OPC did not evaluate whether any specific line was needed to meet the reliability requirements of the North American Electric Reliability Corporation, and it did not review whether SPP planning criteria required any specific project.[655] OPC's testimony does not identify any transmission line, substation, or network upgrade by project name, and it contains no table of the facilities OPC would disallow.[656] Calculating a contribution requires knowing all the assumptions, and OPC "did not get to that level of detail."[657]

OPC's position is nevertheless that a portion of the costs should have been collected from Panasonic.[658] The percentage OPC applied is an "approximation" and "an estimate."[659] Chair Hahn asked whether it could therefore be adjusted up or down, and OPC's witness answered, "[A]bsolutely, with more information, absolutely, and probably we should be."[660] OPC identifies no imprudent decision by the Company at any percentage, because the facilities were built at SPP's direction, SPP allocates their costs, and the decisions OPC faults were, in its own words, "decisions

[652] Tr. Vol. 10 at 45:11–13 (Alvarez).
[653] See Tr. Vol. 10 at 44:25–45:21, 46:10–14 (Alvarez).
[654] See Tr. Vol. 10 at 46:15–18 (Alvarez).
[655] See Tr. Vol. 10 at 46:19–47:5 (Alvarez).
[656] See Tr. Vol. 10 at 43:20–44:13 (Alvarez).
[657] Tr. Vol. 10 at 48:18–24 (Alvarez).
[658] See Tr. Vol. 10 at 47:1–10 (Alvarez).
[659] See Tr. Vol. 10 at 49:6–18 (Alvarez).
[660] Id.

made by Evergy Kansas Central and the Kansas Corporation Commission."[661] A disallowance requires both imprudence and resulting harm to customers, and OPC has shown neither.[662]

The Commission should reject OPC's proposed $14.7 million reduction to rate base for the transmission facilities associated with the Panasonic delivery point.

19. Distribution Investment (EMM: Mulvany, Alexander, De Stigter, Rietcheck, Gunn; Staff took no position on A, Bowman on B; OPC: Alvarez; Shapley)

A. What level of distribution capital investment should be reflected in rate base?

The Company's distribution capital investment should be reflected in rate base in full. OPC would exclude $21.8 million of investment in the Company's Lateral Improvement Program and $20.8 million of substation equipment replacements.[663] Staff recommends no disallowance.[664] Staff also takes no position on OPC's disallowance.[665] The prudence standard discussed under Issue 20.F governs, and under that standard both the lateral program and the substation replacements delivered reliability value.

The Lateral Improvement Program Delivered Reliability Value, as OPC's Own Analysis Shows

The Lateral Improvement Program began in 2014 and funds smaller, targeted projects that circuit-level programs miss, with field investigation deciding the remedy for each.[666] The $21.8 million "represents 2.9% of Evergy's total investment in distribution lines during this period."[667] OPC's own revised analysis found that reliability on the 2022 rebuilt laterals improved, because the System Average Interruption Duration Index "fell from 153.06 minutes on average pre-rebuild

[661] Ex. 201, Alvarez Surrebuttal at 32.
[662] See State ex rel. Associated Natural Gas Co. v. Public Service Commission, 954 S.W.2d 520, 529–30 (Mo. App. W.D. 1997).
[663] See Ex. 220, Shapley Direct at 17; id. at 18; Ex. 221, Shapley Surrebuttal at 34; id. at 19; id. at 25.
[664] See Ex. 129, Bowman Rebuttal at 13.
[665] See Tr. Vol. 9 at 49:25–50:2, 50:11–18 (Staff counsel).
[666] See Tr. Vol. 9 at 61:19–63:20 (Alexander); Ex. 1, Alexander Rebuttal at 16.
[667] Ex. 1, Alexander Rebuttal at 12–13; id. at 5–6.

to 122.60 minutes on average post-rebuild," and using a Department of Energy tool OPC valued that improvement at "a present value of $13.82 million," a benefit-cost ratio of about 0.85.[668] OPC prefers a re-run on a different customer mix, which lowers the value to $6.38 million.[669] OPC nevertheless would disallow all of the program's costs.[670] A full disallowance treats the program as having delivered no value to customers, but either of OPC's figures shows otherwise. OPC's analysis also covers only projects completed in 2022.[671] The Company's comparison of those same laterals found that, "[f]or the most part," the 2022 laterals improved compared to previous years and to a control group.[672] OPC also did not calculate the outages or customer minutes of interruption that its lateral and transformer recommendations would produce, or their safety effects; it performed no project-specific reliability study; and whether customers would be better off under its recommendations is, as its witness agreed, unknown.[673]

The Substation Transformer Replacements Rested on Documented Condition, and OPC's Rebuild Assumption Is Unsupported

The remaining substation disallowance is $20.8 million, after OPC withdrew two other substation recommendations on finding the Company's rebuttal "sufficiently compelling."[674] Part of what remains, for four transformer replacements, rests on OPC's assumption about the cost of rebuilding a transformer, grounded only in its witness's experience, and the rest, $12.9 million, rests on OPC's view that the Company did not document standard operating procedure steps before four other replacements.[675] Factory rebuilds of substation transformers, however, "typically cost 70%-plus of a new unit," all-in "rebuilds will run 80-90% the cost of new transformer," and a

[668] Ex. 221, Shapley Surrebuttal at 13.
[669] Id. at 14.
[670] Id. at 14.
[671] Id. at 12–13.
[672] Ex. 1, Alexander Rebuttal at 28.
[673] See Tr. Vol. 10 at 29:24–30:8, 30:21–31:12, 31:13–32:4 (Shapley).
[674] Ex. 221, Shapley Surrebuttal at 18.
[675] Id. at 20–21, 23–24.

rebuilt unit carries a warranty of "1-2 years at most," against "5-7 years" for a new one.[676] Age is "only one factor," and the units OPC challenges had documented condition issues or a dual load-tap-changer design that is prone to unpredictable failure.[677] Indeed, "equipment failure is the leading cause of customer outages during normal, blue-sky operating conditions."[678] OPC's testimony does not identify the transformer projects by name or substation, so a reader of that testimony alone would not know which projects make up the $20.8 million.[679]

The Commission should include the Company's distribution capital investment in rate base and reject OPC's proposed disallowances of $21.8 million and $20.8 million.

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

Yes. The Company's asset prioritization methodology is a reasonable basis for the investment reflected in this case. OPC answers no, contending that the Company is not comparing the projected service benefits of replacement and refurbishment with their costs.[680] Staff states that the Company uses its AssetLens analysis as the cost-benefit basis for the replacement projects, adds that the analysis was not available for its review and that the Company does not retain the benefit-cost ratios, and recommends no disallowance because it found insufficient evidence to support one.[681] The methodology compares benefits with costs through AssetLens, which engineering judgment and field verification complete, and Staff's concern is access to that analysis rather than the value of the investment.

[676] Ex. 78, Rietcheck Rebuttal at 16, 17.
[677] Id. at 18; id. at 16–17, 21.
[678] Id. at 8.
[679] See Tr. Vol. 10 at 33:3–24 (Shapley).
[680] See Ex. 200, Alvarez Direct at 14; id. at 16; id. at 18; Ex. 220, Shapley Direct at 18.
[681] See Ex. 129, Bowman Rebuttal at 11, 12, 13; Tr. Vol. 9 at 50:18–51:7 (Staff counsel).

AssetLens Is a Decision-Support Tool That Engineering Judgment and Field Verification Complete

The Company's methodology begins with AssetLens, a software platform that applies the results of analytics that evaluate "probability of failure, consequence of failure, lifecycle risk, investment benefits, project costs, and benefit-cost information," using the Company's own asset, outage, customer, and cost data with no employee-entered scores.[682] AssetLens is "a decision-support tool" and "only the starting point," and final investment decisions also rest on engineering judgment and field verification.[683] Asset management engineers review each project, and field visits confirm its scope.[684] OPC agrees "that parts of the software are objectively sound."[685] OPC also agrees that "[i]t appears that technical reviews were appropriately completed on all projects."[686] AssetLens is the primary tool the Company relies on for cost-benefit analysis, and AssetLens relies in turn on the Interruption Cost Estimate ("ICE") calculator, developed by the Department of Energy and used industrywide.[687] OPC's own witness uses the ICE calculator.[688] As discussed under Issue 19.A, that tool assigns value to the 2022 lateral projects on either of OPC's customer mixes.

Commissioner Mitchell asked Staff's witness whether other utilities use AssetLens and whether it is an industry standard.[689] Company witness Jason De Stigter explained that AssetLens displays and manages the results of 1898 & Co.'s analytical model.[690] Some utilities use that model's results in their own planning systems, and others use AssetLens as a dedicated platform.

[682] Ex. 12, De Stigter Rebuttal at 5; id. at 6–7.
[683] See Ex. 70, Mulvany Surrebuttal at 6–7.
[684] See Ex. 1, Alexander Rebuttal at 16–17.
[685] Ex. 201, Alvarez Surrebuttal at 23.
[686] Ex. 200, Alvarez Direct at 19.
[687] See Tr. Vol. 9 at 65:1–66:2, 66:19–21 (Alexander).
[688] See Tr. Vol. 10 at 27:9–28:1 (Shapley).
[689] See Tr. Vol. 9 at 73:7–74:2, 74:7–75:1 (Bowman).
[690] See Ex. 12, De Stigter Rebuttal at 8–10.

In either case, the analytical framework is the same.[691] Mr. De Stigter also testified that the Public Utility Commission of Texas used that modeling approach and model to approve over $4 billion of system resiliency plans for six utilities.[692]

Staff's Concern Is Access to the Underlying Analysis, Not the Value of the Investment

The complete historical scoring dataset was not readily available at the time of the original discovery request because the lateral program predated AssetLens, the platform had undergone multiple versions, and some projects were identified before AssetLens was implemented. EMM subsequently located archived exports from the 2020 AssetLens pilot, filled the previously identified gaps, and filed a supplemental discovery response providing a holistic view of the scoring used for the lateral projects at issue.[693] Each recommended project had an associated benefit-cost ratio, and a ratio greater than one indicates that the project's estimated benefits exceed its estimated replacement cost.[694] Although the proprietary details of how 1898 & Co. calculates the individual benefit components cannot be disclosed, that limitation concerns the ability to independently reproduce the model's calculation. It does not mean that EMM failed to provide the scores, failed to perform benefit-cost analysis, or failed to demonstrate value. Staff would need evidence that the investments did not provide reliability value to conclude that they were imprudent.[695] The Partial Stipulation addresses transparency going forward by providing for reporting on future projects, including approved capital spending authorizations and the materials presented to management.[696]

[691] See id. at 11.
[692] See id. at 20–21.
[693] Ex. 1, Alexander Rebuttal at 16–17.
[694] Ex. 1, Alexander Rebuttal at 14–16.
[695] See Ex. 129, Bowman Rebuttal at 12.
[696] See Partial Stipulation at ¶¶ 17–18.

The Commission should approve the Company's asset prioritization methodology as a reasonable basis for the investment reflected in this case.

IX. INCOME-ELIGIBLE PROGRAMS AND ENERGY BURDEN ANALYSIS

16. Income-Eligible Programs (EMM: McDonald; Staff: Eichholz, King, Huber, Lange, Mastrogiannis, Ferguson; OPC: Marke)

The Company respectfully requests that the Commission approve the Programs Stipulation, which resolves Issues 16.A through 16.D and 16.F through 16.H.[697] OPC objected to the Programs Stipulation only on Issue 16.E, while Google, MECG, and Velvet Tech did not oppose it.[698] On Issue 16.E, the Commission should decline to create the customer charge waiver OPC requests, and any such program should continue to be developed in the Commission's affordability workshop, Case No. OW-2026-0085 ("Affordability Workshop").[699] The Commission should also note that Issues 16.A through 16.D are unopposed by every party, and the only remaining issue is Issue 16.E, the creation of a customer charge waiver program.

A. What level of Critical Medical Needs and Rehousing Programs expense should be included in the revenue requirement?

The revenue requirement should include the Programs Stipulation's annual funding of $600,000 for the Critical Medical Needs Program and $250,000 for the Rehousing Program, each shared 50/50% between ratepayers and shareholders.[700] The Programs Stipulation increases Staff's true-up rebuttal revenue requirement by $313,056 to reflect 50% of the increased program funding.[701]

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[697] See Non-Unanimous Programs Stipulation and Agreement, In re: Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service, No. ER-2026-0143 at 3–4 (Oct. 7, 2026).
[698] Id. at ¶¶ 17–18.
[699] See Order Opening Working Case and Directing Responses, In re Working Case for Commission Review and Consideration of Utility Assistance Programs and Special Alternative Residential Customer Rates, No. OW-2026-0085 (Oct. 1, 2025).
[700] See Programs Stipulation at ¶ 2.
[701] Id. at ¶ 5.

B. What level of economic relief pilot program ("ERPP") expense should be included in the revenue requirement?

Per the Programs Stipulation, the revenue requirement should include annual Economic Relief Program funding of $1,410,000, shared 50/50% between ratepayers and shareholders.[702] The $150,000 increase from the current $1,260,000 is the amount the Programs Stipulation reallocates from the third-party energy burden request at issue in Issue 38.[703]

C. Should the pilot designation be removed from EMM's ERPP tariff?

Yes. The Programs Stipulation removes the word "Pilot" from the ERP's name.[704]

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?

Yes. The Programs Stipulation requires the Company to file the Rehousing Program summary in EFIS, as a non-case filing under the Low-Income Bill Payment Programs Report subtype, at the conclusion of each program year.[705]

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?

No. A customer charge waiver program should continue to be developed in the Affordability Workshop. OPC requests the Commission create a program that waives the customer charge for qualifying low-income customers, with a $6 million annual budget, no restrictions, and eligibility set at 150% of the federal poverty level ("FPL"), 60% of state median income, or the threshold the Department of Social Services uses for the Low-Income Home Energy Assistance

[702] Id. at ¶ 2.
[703] Id. at ¶¶ 2, 4.
[704] Id. at ¶ 2.
[705] Id. at ¶ 2.

Program.[706] This budget is in addition to the approximately $6 million dollars contained in the other low-income programs addressed in the Stipulation and Agreement.

However, the Affordability Workshop is the appropriate proceeding to address OPC's proposal. The Company is "not opposed conceptually to the intent nor to entertaining customer charge modification, but it must be at the appropriate time with the appropriate cost benefit analysis."[707] Consideration of OPC's recommendations in this case is therefore premature "while the Affordability Workshop is actively considering such issues."[708] Staff likewise "needs additional time to collect data to determine if it could support such a program design, including data on potential impacts to other EMM customers."[709] OPC's witness Dr. Geoff Marke (Chief Economist) agrees the Affordability Workshop "was established to provide a review of and consideration of utility assistance programs and income-eligible residential rate design."[710] Dr. Marke credited the Commission and Staff for "the effort that they have done in . . . the workshop docket" and added, "out of that, you were going to have a lot of good policy."[711]

OPC relies on Section 393.1680, which the General Assembly enacted in 2025.[712] The statute provides that the Commission "may" approve a special alternative residential customer rate or bill discount.[713] The statute requires that any eligibility verification "be done by an independent third party or parties selected by a process established by the commission."[714] The General Assembly also directed the Commission to "promulgate rules to implement the provisions of this

[706] See Ex. 204, Marke Surrebuttal at 15–16.
[707] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 35.
[708] See Ex. 60(C)/61(P), McDonald Rebuttal at 11.
[709] See Ex. 135, Huber Rebuttal at 3.
[710] See Ex. 202, Marke Direct at 48.
[711] See Tr. Vol. 8 at 133:19–135:18 (Marke).
[712] See Ex. 202, Marke Direct at 48.
[713] See Section 393.1680.1.
[714] Id.

section."[715] Approval of an income-eligible rate design, in OPC's view, does not depend on that option.[716] OPC's proposal, however, comes "before the Commission has completed its SB4 working docket, before rules have been finalized, before verification has been established, before costs have been quantified, and before alternatives have been compared."[717]

OPC's proposal began as "a placeholder recommendation," meant to "merely represent a starting point for discussions with interested stakeholders and will likely be modified in future testimony."[718] In surrebuttal, Dr. Marke agreed to treat the waiver as "a soft-capped ($6m) bill assistance program similar to Spire Missouri's program rather than a low-income rate."[719] He added the program's parameters in that same round.[720] He agreed that the proposal had been modified since his direct testimony.[721] Dr. Marke's direct testimony included no expected participation rate.[722] His testimony contains no estimate of the program's cost if every eligible customer enrolled, and he offered only what he described as a directional figure of as much as $11 million.[723] He also did not know whether the income-class analysis behind his cost causation argument is in this record.[724] And yet, he now describes the program as "fully vetted."[725] The Commission "should not convert an admitted placeholder into a tariffed rate without first requiring OPC to quantify the cost, determine cost recovery, evaluate alternatives, assess customer impacts, and resolve implementation issues."[726]

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[715] See Section 393.1680.2.
[716] See Ex. 202, Marke Direct at 54.
[717] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 38.
[718] See Ex. 202, Marke Direct at 52.
[719] See Ex. 204, Marke Surrebuttal at 14, 15.
[720] Id. at 15–16.
[721] See Tr. Vol. 8 at 121:21–122:8 (Marke).
[722] See Tr. Vol. 8 at 122:21–123:2 (Marke).
[723] See Tr. Vol. 8 at 125:8–126:8 (Marke).
[724] See Tr. Vol. 8 at 127:6–128:19 (Marke).
[725] See Tr. Vol. 8 at 132:24–133:2 (Marke).
[726] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 34–35.

The program's base cost is modest: $1.728 million a year for 12,000 customers at the $12 customer charge.[727] The program's scope, however, is open. Dr. Marke lists the program's restrictions as "None."[728] He agreed that the parties could revisit the $6 million budget, and that enrolling more customers would likely add costs.[729] Moreover, the eligible population "could be larger or smaller, participation could vary materially, and administrative costs and late-fee impacts would also need to be evaluated."[730]

The program's administration is also undefined. Staff identified the details a program would need in its tariff, including its budget, eligibility, restrictions, duration, renewal, third-party involvement, and implementation costs.[731] Staff recommends that any approved program carry "a limit on the number of participants and the budget," with evaluation and success criteria.[732] The Company had no implementation-cost information to give Staff because it learned of the proposal from Dr. Marke's testimony.[733]

The Company opposes a customer charge waiver in this case because of its cost and because its eligibility would stack on LIHEAP eligibility.[734] The Company instead directed additional assistance dollars to the ERP to reach customers just above LIHEAP eligibility.[735] The Programs Stipulation increases annual ERP funding from $1,260,000 to $1,410,000, shared 50/50% between ratepayers and shareholders.[736] The increase is the $150,000 OPC requested for

[727] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 25; Ex. 138, Sarah Lange Rebuttal at 71.
[728] See Ex. 204, Marke Surrebuttal at 16.
[729] See Tr. Vol. 8 at 124:11–18, 126:22–127:5, 131:9–13 (Marke).
[730] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 24–25.
[731] See Ex. 135, Huber Rebuttal at 3–4.
[732] Id. at 7.
[733] Id. at 4–5.
[734] See Tr. Vol. 12 at 154:8–16 (Gunn).
[735] Id. at 154:17–155:4.
[736] See Programs Stipulation at ¶ 2.

an energy burden study, which the Programs Stipulation reallocates to the ERP.[737] OPC did not object to the Programs Stipulation except as to the absence of a customer charge waiver.[738]

The ERP reaches customers the waiver would not. ERP eligibility extends to households at or below 200% of FPL.[739] OPC would set waiver eligibility at 150% of FPL, 60% of state median income, or the LIHEAP threshold used by the Department of Social Services.[740] The waiver would therefore direct its benefit to customers within LIHEAP's eligibility tests, while ERP dollars also reach the band of households above them.[741] OPC's proposed $6 million budget is more than four times the ERP's entire annual funding under the Programs Stipulation.[742]

The ERP's results are in this record. ERP participants faced service severance in 2025 at a 2.84% rate, compared to 7.64% for similar customers not enrolled, making them about 60 percent less likely to face severance.[743] The ERP helps participants manage their payments and remain current on their accounts.[744] The Company is also working to enroll eligible customers who have not participated, including customers held back by credit or collection requirements.[745] The Company's assistance programs are designed to complement federal and state assistance, so that utility dollars are leveraged alongside those funding streams.[746] The Company hosts events at its Kansas City Connect facility where partner agencies offer LIHEAP assistance, and in 2025 it linked EMM customers to $5,783,000 in bill payment support.[747]

[737] See Programs Stipulation at ¶¶ 2, 4; Ex. 60(C)/61(P), McDonald Rebuttal at 11.
[738] See Programs Stipulation at ¶ 18.
[739] See Contessa King Rebuttal at 2 n.1; Ex. 60(C)/61(P), McDonald Rebuttal at 10.
[740] See Ex. 204, Marke Surrebuttal at 15–16.
[741] See Tr. Vol. 12 at 154:17–155:4 (Gunn).
[742] See Ex. 204, Marke Surrebuttal at 15–16; Programs Stipulation at ¶ 2.
[743] See Contessa King Rebuttal at 3.
[744] See Ex. 60(C)/61(P), McDonald Rebuttal at 9–10.
[745] See Ex. 62, McDonald Surrebuttal at 3.
[746] See Ex. 59, McDonald Direct at 3.
[747] Id. at 5, 11.

The Commission asked whether the ERP forgives arrears as a customer makes payments toward them.[748] The ERP does not forgive arrears as payments are made.[749] Rather, it provides a monthly bill credit of up to $65 for 12 consecutive months, calculated from the customer's average bill over the prior 12 months.[750] At the end of that period, the customer may reapply.[751] The ERP tariff revisions attached to the Programs Stipulation would allow the Company to accept customers with outstanding arrearages into the program.[752] They would also allow the Company, in coordination with the participant, to "apply available program assistance toward the participant's arrearages."[753] The Company addresses arrears directly through its Rehousing Program, which provides eligible customers up to $1,000 toward an electric arrearage and applies any remainder to future electric payments.[754] The Critical Medical Needs Program also addresses the build-up of arrears for medically and cognitively vulnerable customers.[755] The Programs Stipulation keeps Rehousing funding at $250,000 and increases Critical Medical Needs funding to $600,000.[756] Arrearage management is among the issues the Affordability Workshop is examining, alongside rate design, bill assistance, and program coordination.[757] An arrearage-forgiveness feature, like the customer charge waiver, should be developed there, where the Commission can avoid inconsistent or duplicative program structures.[758]

The Commission should not create a customer charge waiver program in this case.

[748] See Tr. Vol. 12 at 155:15–21 (Gunn).
[749] See Programs Stipulation at ¶ 3 & attached P.S.C. MO. No. 3, Original Sheet Nos. R-10.03 to R-10.06.
[750] See Contessa King Rebuttal at 2 n.1; Ex. 59, McDonald Direct at 4.
[751] See Contessa King Rebuttal at 2 n.1.
[752] See Programs Stipulation at ¶ 3 & attached P.S.C. MO. No. 3, Original Sheet No. R-10.04.
[753] Programs Stipulation at ¶ 3 & attached P.S.C. MO. No. 3, Original Sheet No. R-10.05.
[754] See Ex. 59, McDonald Direct at 9–10.
[755] Id. at 8–9.
[756] See Programs Stipulation at ¶ 2.
[757] See Ex. 62, McDonald Surrebuttal at 2.
[758] Id.

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

The Commission need not reach this question. If the Commission creates a program, it should not waive late fees, because the record contains no late-fee design. Staff is not opposed to an assistance program that would waive late fees, but it "requires the full details of a potential program to develop a position."[759]

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

The Commission need not reach this question either. The parties that address recovery disagree. Staff would allocate the waived revenues to all classes "on the basis of the otherwise-applicable class revenue requirements," like economic development incentives, or alternatively treat them as an expense.[760] MECG would recover the waived revenues from the residential class or, if they are recovered from all classes, allocate them on a per-customer basis.[761] Dr. Marke would split the cost between customers and shareholders.[762] He agreed that the revenue requirement should then include a provision for the program's expected cost, and he would decide class allocation in a future rate case.[763] That disagreement is one more reason to develop any program in the Affordability Workshop.

The Commission need not decide how waived revenues would be recovered.

F. Should EMM be required to file quarterly Rehousing Program reports in EFIS in addition to the existing year-end report?

No. The Programs Stipulation provides for the year-end Rehousing Program summary in EFIS and no quarterly report.[764]

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[759] See Staff Positions at 12.
[760] See Ex. 138, Sarah Lange Rebuttal at 71.
[761] See Ex. 305, York Surrebuttal at 42.
[762] See Ex. 204, Marke Surrebuttal at 15.
[763] See Tr. Vol. 8 at 133:8–16 (Marke).
[764] See Programs Stipulation at ¶ 2.

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?

The Commission should approve the Rehousing and ERP tariff revisions attached to the Programs Stipulation, which gives the Company more flexibility in program administration.[765] The Programs Stipulation keeps each program's funding dedicated to that program, with no transfers among programs.[766]

H. What level of Low-Income Weatherization Program expense, if any, should be included in the revenue requirement?

Per the Programs Stipulation, the revenue requirement should include annual Income-Eligible Weatherization Program funding of $750,000, shared 50/50% between ratepayers and shareholders.[767]

38. Energy Burden Analysis (EMM: McDonald, Lutz; Staff took no position; OPC: Marke)

The Commission should approve the Programs Stipulation, which resolves Issue 38.A for its signatories.[768] OPC's objection to the Programs Stipulation is limited to Issue 16.E.[769]

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

No. The Programs Stipulation removes the third-party energy burden tool development request and reallocates its $150,000 to the ERP.[770]

X. RATES AND REVENUE RESPONSIBILITY

The Company respectfully requests that the Commission adopt the Rate Design Settlement and decline to order Staff's proposed CPR. The commercial and industrial classes are Small

[765] Id. at ¶ 3.
[766] Id. at ¶ 2.
[767] Id.
[768] See Programs Stipulation at 4.
[769] Id. at ¶ 18.
[770] Id. at ¶ 4.

General Service ("SGS"), Medium General Service ("MGS"), LGS, and LPS.[771] Under the Rate Design Settlement, Schedule LLPS is a subclass of LPS.[772] LPS and LGS earn well above the system average return, and the Rate Design Settlement gives them less than the average increase. It holds the residential class at the average increase.[773] Staff objected to the Rate Design Settlement in part, and OPC opposed the shifts in revenue responsibility among classes and the other terms its opposition lists.[774]

OPC gives no reason for any of those other terms.[775] The Commission's stipulation rule requires an objecting party to "identify the specific provision of the stipulation and agreement that is objected to and provide a reason for each objection."[776] The Commission adopted that language in 2024 at OPC's suggestion.[777] Where OPC gives no reason for opposing a term, its opposition does not satisfy the rule and should be disregarded.

This section also answers Chair Hahn's questions on billing determinants under Issue 29.A.iv, the LPS increase under Issue 30.A.ii, the cost studies under Issue 32.A, and the allocation of CWIP under Issue 32.D.

29. Non-Residential Rate Design (EMM: Jaynes, Lutz; Staff: Lange; MECG: York)

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

Yes. The Rate Design Settlement's unopposed terms resolve Issues 29.A and 29.A.i. The contested sub-issues follow.

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[771] See Ex. 33, Jaynes Direct at 33.
[772] See Rate Design Settlement at ¶ 2.
[773] See id.; Ex. 33, Jaynes Direct at 45.
[774] Rate Design Settlement at 3–5 & ¶ 11; MECG Response at ¶ 3; Staff Rate Design Objection at ¶¶ 3–14; OPC Rate Design Opposition at ¶¶ 1–4.
[775] See OPC Rate Design Opposition at ¶ 4.
[776] 20 CSR 4240-2.115(2)(B).
[777] See Comments of the Office of the Public Counsel at 3, In re Amendment of the Commission's Rule Regarding Stipulations and Agreements, No. OX-2024-0255 (May 30, 2024); Order of Rulemaking, 20 CSR 4240-2.115, 49 Mo. Reg. 1406 (Sept. 16, 2024).

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

ii. Should the Large General Service and Medium General Service classes be subject to reactive demand charges?

No. The Commission should remove the Reactive Demand Adjustment from the MGS and LGS classes, as the Rate Design Settlement provides, while the charge remains in place for LPS and Schedule LLPS.[778] Large customers disproportionately drive reactive demand, the revenue involved is small, and removal is revenue neutral within each class.

Large Customers Disproportionately Drive Reactive Demand, and the Charge Remains Where They Are

"[A]ll customers affect reactive demand, but large customers disproportionately due to large motors, pumps, and equipment commonly used by their operations."[779] Most customers contribute in small ways that they cannot control apart from their other energy use, and for those classes a specific charge "is not useful or necessary."[780] Removal also aligns the Company with Evergy Missouri West, a separate utility, where only the LPS class retains the charge.[781] The revenue involved is small, because reactive demand revenues are 0.142 percent of MGS revenue and 0.136 percent of LGS revenue.[782] Removing the charge is also revenue neutral within each class, because the revenue it now produces will be recovered through the class's other billing determinants.[783]

[778] See Rate Design Settlement at 2; see also Ex. 54, Lutz Direct at 11–13; Ex. 57(HC)/58(P), Lutz Surrebuttal at 23–24; Ex. 33, Jaynes Direct at 30.
[779] Ex. 57(HC)/58(P), Lutz Surrebuttal at 24.
[780] Id. at 24.
[781] See Ex. 33, Jaynes Direct at 30.
[782] Id. at 30.
[783] Id. at 30.

Staff's Reactive-Demand Concern Is Answered by the Small Share Those Customers Contribute

Staff would keep the charge for MGS and LGS.[784] Staff witness Sarah Lange contends that reactive demand is becoming more significant, citing areas with less rotating mass generation and the growth of rapidly fluctuating loads.[785] The Company does not agree that there is an increasing need to address reactive demand.[786] In any event, the Rate Design Settlement keeps the charge for LPS and Schedule LLPS, the disproportionate contributors.[787]

OPC Opposes Removal Without Stating a Reason

OPC lists the term among those it opposes and states no reason.[788] OPC has therefore not satisfied the stipulation rule, and its opposition should be disregarded.[789] The Commission should remove the Reactive Demand Adjustment from the MGS and LGS classes, as the Rate Design Settlement provides.

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

The appropriate charges are those the Rate Design Settlement sets. The Rate Design Settlement adopts the Company's demand thresholds and its move from 30-minute to 15-minute billing demand, eliminates the commercial and industrial all-electric rates, sets a demand factor of 1.25 and an energy factor of 0.75 for LPS and LGS, and commits the Company to review voltage-differentiated rates in its next general rate case.[790] Staff and MECG do not oppose the thresholds or the 15-minute demand. Staff's 15 percent alternative factors rest on no cost-of-service analysis, and OPC opposes the terms without a reason.

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[784] See Staff Rate Design Objection at ¶ 9.
[785] See Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 32; Ex. 138, Sarah Lange Rebuttal at 68–69.
[786] See Ex. 57(HC)/58(P), Lutz Surrebuttal at 24.
[787] See Rate Design Settlement at 2; Ex. 57(HC)/58(P), Lutz Surrebuttal at 24.
[788] See OPC Rate Design Opposition at ¶ 4; 20 CSR 4240-2.115(2)(B).
[789] See 20 CSR 4240-2.115(2)(B).
[790] See Rate Design Settlement at 2; see also Ex. 33, Jaynes Direct at 13–17; id. at 28; Ex. 305, York Surrebuttal at 24.

Staff and MECG Do Not Oppose the Thresholds or the 15-Minute Billing Demand

The Company proposed thresholds of 31 kW, 250 kW, and 3,000 kW, and a 15-minute interval captures peak usage more accurately.[791] Staff does not object to the thresholds or the 15-minute billing demand.[792] MECG witness Jessica York (consultant, Brubaker & Associates, Inc.) does not oppose them either.[793]

Staff's Own 15 Percent Alternative Has No Cost-of-Service Support, and the Demand-Energy Term Is Definite

Staff objects to the LPS and LGS factors, contending that they are arbitrary and may produce unreasonably low energy rates.[794] On the Company's study of the restructured classes, however, energy costs are about 30 percent of the LPS cost of service, while the proposed LPS energy rates recover about 65 percent of that class's revenue requirement.[795] For LGS, the figures are about 25 percent and 60 percent. "[T]he rate structure already recovers a substantial amount of fixed, capacity-related cost through volumetric charges."[796] MECG's witness recommended factors of 1.5 and 0.5.[797] The Rate Design Settlement takes a smaller step in the same direction. Staff's own alternative would recover about 15 percent of the revenue in each restructured class from billing demand charges.[798] "Staff has not identified a cost-of-service analysis supporting the 15% figure."[799]

Staff also contends that the term is too vague to apply, and that applying it to the Company's originally proposed rates would be improper.[800] The term provides: "Demand component to

[791] See Ex. 33, Jaynes Direct at 13; id. at 17.
[792] See Staff Rate Design Objection at ¶ 4; Ex. 138, Sarah Lange Rebuttal at 56–57.
[793] See Ex. 302, York Direct at 3.
[794] See Staff Rate Design Objection at ¶ 8(a).
[795] See Ex. 305, York Surrebuttal at 24.
[796] Id. at 24.
[797] Id. at 24.
[798] Id. at 23.
[799] Id. at 24.
[800] See Staff Rate Design Objection at ¶ 8(b).

increase 1.25 times class average assigned to LPS / LGS, Energy to increase 0.75 with the remainder of the class rev. requirement recovered from the remaining rate elements."[801] The Company's direct-case rates were indicative, and "[t]he final rates will be based on the Commission's approved revenue requirement and corresponding billing determinants for the rate class."[802] The Company will begin with the billing determinants it accepted from Staff and then apply the other stipulations.[803]

Staff would complete the voltage review before any restructured rates take effect.[804] Staff and MECG each questioned voltage relationships in the Company's proposed rates.[805] The Company continued to evaluate MECG's observations.[806] The Rate Design Settlement commits the Company to review voltage-differentiated rates in its next general rate case "to appropriately reflect voltage cost differences."[807] MECG, whose witness raised the issue, agreed to that course.[808] Staff's substitute is its own pricing from the Rate Design Report, and Staff's facilities charge levels "are illustrative and are not tied to a cost study."[809] Staff "does not object to the elimination of all C&I electric rates."[810] Staff has long opposed these end-use rates and would keep them only until the restructured rates take effect, a timing question addressed under Issue 29.A.vi.[811]

[801] Rate Design Settlement at 2.
[802] Ex. 33, Jaynes Direct at 22.
[803] See Tr. Vol. 12 at 106:13–22 (Lutz).
[804] See Staff Rate Design Objection at ¶ 10.
[805] See Ex. 138, Sarah Lange Rebuttal at 65–67; Ex. 305, York Surrebuttal at 29.
[806] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 46.
[807] Rate Design Settlement at 2.
[808] Id. at 2; MECG Response at ¶ 3.
[809] Ex. 305, York Surrebuttal at 25; see Staff Rate Design Objection at ¶ 10.
[810] Staff Rate Design Objection at ¶ 13.
[811] Id. at ¶ 13; Tr. Vol. 12 at 171:10–21 (Sarah Lange).

OPC Opposes the Thresholds and Related Terms Without Stating a Reason

OPC lists the thresholds, the 15-minute demand, the voltage review, and the all-electric elimination among the terms it opposes, and it gives no reason for any of them.[812] OPC has therefore not satisfied the stipulation rule as to those terms, and its opposition should be disregarded.[813] OPC's opposition does not identify the demand-energy factors for LPS and LGS at all, so OPC has waived its right to a hearing on them.[814]

The Commission should adopt the charges and rate structures in the Rate Design Settlement, including the demand thresholds, 15-minute billing demand, the demand-energy factors for LPS and LGS, elimination of the all-electric rates, and a review of voltage-differentiated rates in the Company's next general rate case.

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

No. The Rate Design Settlement contains no study term and lists Issue 29.A.iv as resolved between the signatories.[815] The record already contains what the study would produce, and the remaining work is a compliance calculation that does not justify delaying the restructured rates.[816]

The Record Contains the Billing Determinants, and the Remaining Work Is a Compliance Calculation

In the Partial Stipulation, the Company accepted Staff's non-LLPS billing determinants for the current classes.[817] The Company applied the proposed thresholds to customer data and estimated that 4,224 customers would migrate between classes.[818] The Company converted billing

[812] See OPC Rate Design Opposition at ¶ 4; 20 CSR 4240-2.115(2)(B).
[813] See 20 CSR 4240-2.115(2)(B).
[814] See OPC Rate Design Opposition at ¶¶ 1–4; 20 CSR 4240-2.115(2)(B).
[815] See Rate Design Settlement at 3.
[816] See Ex. 33, Jaynes Direct at 14–17; Ex. 36, Jaynes Surrebuttal/True-Up Direct at 3–5; Ex. 55(HC)/56(P), Lutz Rebuttal at 12.
[817] See Partial Stipulation at ¶ 3.
[818] See Ex. 33, Jaynes Direct at 14.

demand to a 15-minute basis with a factor developed from customer-level interval data.[819] The Company filed a CCOS study for the restructured classes.[820] "[T]he Company fully supported the migrations and offered updated billing determinants to support its proposal."[821] The Company has the information it needs and has aligned its determinants with the stipulations.[822] The remaining adjustments are the type made in other rate cases.[823]

Chair Hahn Questioned Staff's Claim That There Are No Billing Determinants and Asked What Staff's Study Would Produce

In its opening statement, Staff told the Commission that "there are no determinants to calculate the rates that EMM and MECG have stipulated to."[824] Chair Hahn raised the point with Staff's counsel: "I think there are billing determinants. I'm trying to figure out the disparity."[825] Staff's counsel answered that "[t]here are no billing determinants" for the Company's agreement with MECG.[826] Staff's written objection says the same.[827] The claim is not correct, because the record contains the billing determinants described above. Staff's witness later denied that anyone had made the claim: "I don't think anyone said there's no billing determinants in this case."[828] Staff's view is instead that the Company did not follow the proper process to develop them.[829]

Chair Hahn also asked Company witness Brad Lutz (Director, Regulatory Affairs) what a customer migration or billing determinant study would produce. She explained that she was "trying to discern the cost and benefits of such studies."[830] He answered that the migration studies

[819] Id. at 17.
[820] Id. at 46.
[821] Ex. 55(HC)/56(P), Lutz Rebuttal at 12.
[822] See Tr. Vol. 12 at 105:8–17, 106:7–12 (Lutz).
[823] See Tr. Vol. 12 at 107:11–13 (Lutz).
[824] See Tr. Vol. 6 at 31:5–7 (Staff counsel); Tr. Vol. 12 at 25:21–24 (Chair Hahn).
[825] Tr. Vol. 12 at 25:21–24 (Chair Hahn).
[826] Tr. Vol. 12 at 26:1–8 (Staff counsel).
[827] See Staff Rate Design Objection at ¶ 8(d).
[828] Tr. Vol. 12 at 175:12–19 (Sarah Lange).
[829] See Tr. Vol. 6 at 33:11–24 (Staff counsel); Tr. Vol. 12 at 175:7–11 (Sarah Lange).
[830] Tr. Vol. 12 at 111:11–14 (Chair Hahn).

are in the Company's direct testimony, and that "Staff does not agree with the mechanisms that we've used, not that there's no study."[831] Asked whether he had ever seen such a study conducted in any case, he answered that he had not.[832]

Staff Identifies No Alternative Determinants and No Case in Which a Study Delayed a Rate Change

Staff requests that the Commission order a customer migration and determinants study before the restructured rates take effect.[833] Staff told the Company in discovery that it considers the method behind the conversion factor unreasonable, but Staff did not identify an alternative factor, stating that it had not received the customer information it requested.[834] The factor translates billed 30-minute demand to a 15-minute basis only to set revenue-neutral rates, and "[a]fter this initial conversion in determinants, actual bills will be based on each customer's metered demand."[835] Staff's approach would require the Company to evaluate approximately 34,000 customers and process billions of interval data records, and for that limited purpose "that exercise is neither necessary nor proportionate."[836]

Staff describes the study as the work "necessary to calculate rates to be ordered in compliance tariffs in this case."[837] In response to Commissioner Coleman, Staff estimated that the study should take less than a week if the Company devoted time to it.[838] The Company had estimated in discovery that pulling the data Staff requested would take two to three months.[839] Staff would nonetheless delay the restructured rates until November 2027, a date its counsel called

[831] Tr. Vol. 12 at 111:15–20 (Lutz).
[832] See Tr. Vol. 12 at 112:4–6 (Lutz).
[833] See Staff Rate Design Objection at ¶ 8(d).
[834] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 4 (quoting Staff response to Company Data Request 0508).
[835] Id. at 3.
[836] Id. at 3.
[837] Staff Rate Design Objection at ¶ 4.
[838] See Tr. Vol. 12 at 176:22–177:10 (Sarah Lange).
[839] See Ex. 133, Gonzales Rebuttal at 5.

Staff's "best guess."[840] Asked by Commissioner Coleman whether any rate change had been delayed while Staff conducted a study, Staff's witness identified no such case.[841] Asked from the bench about impediments to setting rates, she answered that the Commission has to set rates in this case.[842]

Staff's proposed study should not delay the compliance tariffs that implement the restructured rates. The Company will have its data ready to calculate those rates once the Commission issues its order.[843] Under the Rate Design Settlement, the restructured rates then take effect with the rate increase, by bill cycle, as discussed under Issues 29.A.vi and 32.C.[844] Staff would instead have the Company file two sets of tariff sheets for SGS, MGS, LGS, and LPS customers.[845] One set would increase the current rates for service before November 1, 2027. The other, on new sheet numbers, would carry the restructured rates for service on and after that date. Those customers would see two rate changes within a year, the sequential change the Company's witness testified risks customer confusion.[846] The Commission should therefore direct that the compliance tariffs implementing the restructured rates be filed with the other compliance tariffs in this case, and it should not condition their approval on Staff's study.

OPC's Objection Depends on Staff's Study, Which Is Unnecessary

OPC opposes reallocating revenue responsibility among classes "without a rate mitigation study as Staff recommends."[847] The study Staff recommends is a "customer migration and

[840] Tr. Vol. 12 at 30:21–31:12 (Staff counsel).
[841] See Tr. Vol. 12 at 180:7–181:8 (Sarah Lange).
[842] See Tr. Vol. 12 at 184:18–185:15 (Sarah Lange).
[843] See Tr. Vol. 12 at 105:12–17 (Lutz).
[844] See Rate Design Settlement at 1.
[845] See Staff Positions at 28–29; Tr. Vol. 12 at 183:2–14 (Sarah Lange).
[846] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 18–19.
[847] OPC Rate Design Opposition at ¶ 3.

determinants study," and the record already contains the billing determinants needed to implement the restructured rates.[848]

The Commission should not order a separate billing determinants and customer impact study as a condition of implementing the restructured rates or approving the compliance tariffs that implement them.

v. What customer education is appropriate?

Targeted customer education by the Company after the Commission's order is appropriate and does not require a delay. The Rate Design Settlement contains no education term and lists Issue 29.A.v as resolved between the signatories.[849]

The Company Will Educate Affected Customers After the Commission Rules, as in Past Cases

The Company will rely on its customer service experience and past rate case approaches to educate affected customers once the Commission rules. Its plan will identify affected customers, prepare talking points and educational materials, and set communication channels.[850] Education need not be completed before rates are effective, because "[p]ost rate case customer education has been common."[851] MECG had recommended deferral in direct testimony, but after the Company provided a combined bill impact analysis, MECG no longer recommended deferral "on evidentiary grounds alone" and recommended gradualism through revenue apportionment instead.[852] MECG then joined the Rate Design Settlement.[853]

[848] Staff Rate Design Objection at ¶ 4.
[849] See Rate Design Settlement at 4; see also Ex. 57(HC)/58(P), Lutz Surrebuttal at 7–8; Ex. 36, Jaynes Surrebuttal/True-Up Direct at 19; Ex. 34(HC)/35(P), Jaynes Rebuttal at 45.
[850] See Ex. 57(HC)/58(P), Lutz Surrebuttal at 7–8.
[851] Id. at 8.
[852] Ex. 305, York Surrebuttal at 34.
[853] See MECG Response at ¶ 3.

Customer Notification Can Occur Without Delaying the Approved Rate Structure

Staff objects that immediate implementation brings "a significant change in rate structure in the peak winter billing months, without the benefit of any meaningful customer education."[854] Staff would require customer education, a billing-system test, and a one-time report pricing each customer's last twelve months of usage under the increased current rates and the restructured rates.[855] Staff also faults the Company for not preparing detailed education plans earlier.[856] The Company explained its practice in discovery: because its proposals "can be changed dramatically during the course of the general rate proceeding," detailed plans wait until a proposal appears acceptable.[857] Staff's witness agreed that the Company would not have known in July whether the Commission would approve the restructuring.[858] "[A]dditional customer notification can occur without delaying implementation of the approved rate structure."[859] A report that leads to no specific adjustment is no reason to postpone rate modernization.[860] Rates have typically been implemented at the end of a case without delay for further study or customer education.[861]

OPC's Education Objection Adds Nothing to Staff's

OPC "opposes the intra-class responsibility shifts proposed without customer education."[862]

The Commission should approve targeted customer education by the Company after its order and should not condition implementation on Staff's education plan or one-time report.

[854] Staff Rate Design Objection at ¶ 7(a).
[855] See Ex. 125, Staff Rate Design Report at 28.
[856] See Ex. 138, Sarah Lange Rebuttal at 57–58.
[857] Ex. 57(HC)/58(P), Lutz Surrebuttal at 7 (quoting Company response to Staff Data Request 0238).
[858] See Tr. Vol. 12 at 192:2–4 (Sarah Lange).
[859] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 19.
[860] Id. at 19.
[861] See Tr. Vol. 12 at 104:22–25 (Lutz).
[862] OPC Rate Design Opposition at ¶ 2.

vi. What date should restructured rates take effect?

The restructured rates should take effect with the rate increase, by bill cycle, as the Rate Design Settlement provides: rate design "will take effect in alignment with new effective rates from the rate increase by bill cycle."[863] Delay would keep a structure every party agrees should be replaced for another year.

Delay Keeps a Structure the Parties Agree Should Be Replaced

A delay would keep the Hours Use structure, which the Company and Staff agree should be replaced and which MECG agreed to replace in the Rate Design Settlement.[864] "[D]elay is not neutral," because a one-year delay would preserve the existing structure, delay improved price signals, and risk customer confusion from sequential changes.[865]

Staff's 2027 Effective Date Would Prolong the Hours Use Structure for a Year

Staff would increase the existing rates at the end of the case and put the restructured rates into effect later, outside the peak summer and winter billing months.[866] Staff would apply the restructured rates to service on and after November 1, 2027.[867] Staff's own testimony states that Staff does not support continuing the Hours Use structure beyond a limited transition period.[868] Staff objects to a structural change in the peak winter months without customer education, which Issue 29.A.v addresses.[869] The Company has the information it needs to implement the new rate designs, and about five earlier rate changes for the Company took effect in the December and January period.[870]

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[863] Rate Design Settlement at 1. See also Ex. 36, Jaynes Surrebuttal/True-Up Direct at 18–19; Ex. 57(HC)/58(P), Lutz Surrebuttal at 8; Ex. 55(HC)/56(P), Lutz Rebuttal at 14.
[864] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 13; Staff Rate Design Objection at ¶ 4; MECG Response at ¶ 3.
[865] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 18–19.
[866] See Staff Rate Design Objection at ¶¶ 7, 13; Tr. Vol. 12 at 163:18–164:24 (Sarah Lange).
[867] See Ex. 125, Staff Rate Design Report at 26.
[868] See Ex. 133, Gonzales Rebuttal at 5.
[869] See Staff Rate Design Objection at ¶ 7(a).
[870] See Tr. Vol. 12 at 103:17–104:5 (Lutz).

OPC Did Not Object to the Effective-Date Term

OPC's opposition does not identify the term that sets the effective date.[871] OPC therefore did not object to it and has waived its right to a hearing on it.[872]

The Commission should order the restructured rates to take effect with the rate increase, by bill cycle, as the Rate Design Settlement provides.

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

Yes. The Commission should approve the Company's optional time-of-use rate for non-residential customers, as modified by the Rate Design Settlement, which adopts the proposal with the items resolved for the standard rate incorporated.[873] The rate is cost-reflective and revenue neutral, and paying less in lower-cost periods is the intended result of its design.

The Optional Time-of-Use Rate Is Cost-Reflective and Revenue Neutral

The rate has a customer charge, a facilities charge, a demand charge, and an energy charge. The energy charge has an on-peak period on summer weekday afternoons, a super-off-peak period overnight, and an off-peak period for all other hours.[874] The Brattle Group determined the rate design and pricing.[875] MECG supports the rate.[876]

Paying Less in Lower-Cost Periods Is the Intended Result of the Rate's Design

Staff objects that the rates "are not cost-based and are poorly priced," and objects to their incorporation "absent a commitment from EMM to not burden future cases with an attempt to recover revenues avoided by participating customers."[877] Customers who use electricity in higher-

[871] See OPC Rate Design Opposition at ¶¶ 1–4.
[872] See 20 CSR 4240-2.115(2)(B).
[873] See Rate Design Settlement at 2; see also Ex. 33, Jaynes Direct at 25–27; Ex. 36, Jaynes Surrebuttal/True-Up Direct at 17–18.
[874] See Ex. 33, Jaynes Direct at 25.
[875] Id. at 25.
[876] See Ex. 302, York Direct at 25–26; Ex. 305, York Surrebuttal at 26–29.
[877] Staff Rate Design Objection at ¶ 11.

cost peak periods pay more, and customers who use it in lower-cost periods pay less. "That outcome is not an avoidance of revenue responsibility; it is the intended result of assigning prices to better reflect when costs are incurred."[878] Staff has not quantified the revenue it believes participants would avoid, and it told MECG in discovery that it could not do so at this time.[879] The Company acknowledges that extreme adoption of the optional rate could reduce the revenue it recovers, but the Company may lower its costs as customers shift usage out of higher-cost hours, and "[i]f that occurs, the revenue loss would be offset by the cost savings."[880] Staff itself told MECG in discovery that "it is possible to develop a reasonable rate that maintains some protections against revenue-erosion for non-participating ratepayers and which is based on accurate and cost-based time-differentiated rates."[881]

Staff states that, as to the Company's existing Time Related Pricing ("TRP") tariff, "a well-designed TRP tariff could meet the customer desires that underlie optional highly-differentiated opt-in TOU tariffs."[882] The Company's optional rate "is designed to meet that objective directly."[883] Staff would instead have the parties develop an opt-in rate that bills energy at the day-ahead market price, with reasonable demand and other charges.[884] Yet "[a] rate billed hourly at the day-ahead market price is considerably more differentiated than the optional TOU rate Staff opposes, and it is likewise an opt-in rate."[885]

[878] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 18.
[879] See Ex. 305, York Surrebuttal at 26; Ex. 305, York Surrebuttal, Sch. JAY-SUR-1 at 20–21 (Staff response to MECG Data Request 0537).
[880] Ex. 33, Jaynes Direct at 27.
[881] Ex. 305, York Surrebuttal, Sch. JAY-SUR-1 at 20 (Staff response to MECG Data Request 0537, part 5).
[882] Ex. 138, Sarah Lange Rebuttal at 69.
[883] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 19.
[884] See Ex. 138, Sarah Lange Rebuttal at 69–70.
[885] Ex. 305, York Surrebuttal at 27.

OPC Opposes the Term Without Stating a Reason

OPC lists the optional time-of-use term among the terms it opposes and gives no reason.[886] OPC has therefore not satisfied the stipulation rule, and its opposition should be disregarded.[887]

The Commission should approve the Company's optional time-of-use rate for non-residential customers, as modified by the Rate Design Settlement.

30. Other Rate Schedules (EMM: Jaynes, Lutz; Staff: Lange; Google: Berry; MECG: York; OPC: Marke)

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?

The other rates should be increased as the Rate Design Settlement provides. The Rate Design Settlement increases the electric vehicle and lighting classes by 112.50 percent of the system average increase. Within lighting, LED service receives 25 percent of the class increase rate while the other lighting service recovers the rest of the class deficiency.[888] The TRP rate is addressed under Issue 30.A.i, and Schedule LLPS under Issue 30.A.ii. Staff would increase each of these rates by the same percentage as every other class.[889] OPC opposes the Rate Design Settlement's shifts among classes.[890]

Both of the Company's CCOS studies show these classes earning below the system average return of 4.90 percent. The lighting class earns 3.73 percent, and the electric vehicle class (Electric Vehicle/CCN in the studies) earns a negative return.[891] The lighting increase is weighted toward non-LED components "in an effort to align price signals with technological efficiencies."[892] The

[886] See OPC Rate Design Opposition at ¶ 4; 20 CSR 4240-2.115(2)(B).
[887] See 20 CSR 4240-2.115(2)(B).
[888] See Rate Design Settlement at ¶ 2.
[889] See Ex. 125, Staff Rate Design Report at 4; id. at 26.
[890] See OPC Rate Design Opposition at ¶¶ 1, 3.
[891] See Ex. 33, Jaynes Direct at 33; id. at 45, Table 8; id. at 46, Table 9.
[892] Id. at 52.

Company's direct-case proposal of an equal percentage increase for every class is addressed under Issue 32.A. The Company and Staff agree that rates not set in a general rate case, such as solar subscription block charges, should not receive the increase.[893]

The Commission should increase the electric vehicle and lighting rates by 112.50 percent of the system average increase, with the LED weighting in the Rate Design Settlement. It should not increase rates not set in a general rate case.

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

No. The TRP rate has three active service agreements, two of them under the same account.[894] The Company had proposed to eliminate it.[895] The Rate Design Settlement instead freezes the rate for current non-residential customers and, in this case, increases its components by 1.1 times the system average increase.[896] Staff does not object to the freeze.[897] MECG supports it.[898] OPC opposes both the freeze and the multiplier and gives no reason for either.[899] OPC has therefore not satisfied the stipulation rule, and its opposition should be disregarded.[900]

Staff objects to the 1.1 multiplier, contending that the provision "is being utilized to provide additional avoidance of applicable rate increases to LPS customers."[901] The multiplier, however, increases TRP prices by more than the system average. The Company's testimony called for an increase above the jurisdictional increase "to bring it closer in alignment to that of the TOU

[893] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 12; Ex. 138, Sarah Lange Rebuttal at 55.
[894] See Ex. 33, Jaynes Direct at 29.
[895] Id. at 29.
[896] See Rate Design Settlement at 2.
[897] See Staff Rate Design Objection at ¶ 14; Tr. Vol. 12 at 172:4–10 (Sarah Lange).
[898] See Ex. 305, York Surrebuttal at 30.
[899] See OPC Rate Design Opposition at ¶ 4.
[900] See 20 CSR 4240-2.115(2)(B).
[901] Staff Rate Design Objection at ¶ 14.

equivalent," and it proposed an additional 4.73 percent for that purpose.[902] The Rate Design Settlement's multiplier moves TRP in the same direction.

The Commission should freeze the TRP rate for current non-residential customers and increase its components by 1.1 times the system average increase, as the Rate Design Settlement provides.

ii. Should Schedule LLPS rates be increased in this proceeding, and if so, by how much?

Yes. Schedule LLPS rates should increase as a subclass of LPS, which receives 94 percent of the system average increase under the Rate Design Settlement.[903] The Company derived the Schedule LLPS rate from the LPS rate and committed to keep that relationship until a customer informs ratemaking. Staff's objection to an LLPS increase smaller than the residential increase would break that link.

Chair Hahn Asked About Staff's Objection to the Lower LPS Increase

Chair Hahn asked Mr. Lutz: "One of Staff's objections is that it's lower for the LPS class than the other classes. Can you speak to that?"[904] He answered that this is a transitional case, with no LLPS customer in the test year to inform ratemaking. "If LPS goes up or down, I want LLPS to follow until we have a customer available to inform any other behavior that might be different."[905] Chair Hahn also asked whether the next case would show the large load customers' revenue requirement and billing determinants. Mr. Lutz answered that the Company's next filing will have large load customers and their costs.[906] Why the LPS percentage is below the average increase is addressed under Issue 32.A.

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[902] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 20.
[903] See Rate Design Settlement at ¶ 2; see also Ex. 55(HC)/56(P), Lutz Rebuttal at 47–49; Ex. 36, Jaynes Surrebuttal/True-Up Direct at 21–22; Ex. 33, Jaynes Direct at 48–49.
[904] Tr. Vol. 12 at 114:9–13 (Chair Hahn).
[905] Tr. Vol. 12 at 114:14–25 (Lutz).
[906] See Tr. Vol. 12 at 115:10–20 (Lutz).

Schedule LLPS Rates Were Derived from LPS Rates and Should Move with Them Until a Customer Informs Ratemaking

The Company derived the Schedule LLPS rate from the LPS rate and linked the two.[907] LLPS remains under the initial pricing requirement of the settlement in the Company's LLPS tariff case: "Until there is at least one LLPS customer over 75MW the LLPS rates will maintain their relationship to LPS."[908] This is a transitional case in which no LLPS customer was active during the test year.[909] The Company intends to keep that relationship "until sufficient operational data is available to support a comprehensive cost allocation."[910]

Staff's Equal Percentage Increase Would Break the Link Between LLPS and LPS Rates

Staff would increase Schedule LLPS rates by the same percentage as every other class and objects to an LLPS increase smaller than the increase for residential and small business customers.[911] Staff's recommendation is consistent with the Company's position "in the sense that the Company has proposed maintaining the relationship between LLPS and LPS rates through this case."[912] The difference is the LPS percentage, addressed under Issue 32.A. Staff also contends that the Company's CCOS treatment of LLPS overstates the return of the LPS class.[913] The Company acknowledges that including LLPS in LPS raises the relative LPS return at current rates, but that comparison omits the share of fixed costs that could be apportioned to LLPS in the future.[914] LPS, exclusive of LLPS, earns 9.7 percent at present rates, about double the system average.[915]

[907] See Ex. 55(HC)/56(P), Lutz Rebuttal at 47–49.
[908] Ex. 33, Jaynes Direct at 49.
[909] Id. at 48.
[910] Id. at 48.
[911] See Ex. 138, Sarah Lange Rebuttal at 16; id. at 22; Staff Rate Design Objection at ¶ 6(c).
[912] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 22.
[913] See Ex. 138, Sarah Lange Rebuttal at 9.
[914] See Ex. 33, Jaynes Direct at 47.
[915] See Ex. 302, York Direct at 12.

Google Opposes an Increase but Does Not Oppose the Rate Design Settlement

Google's Statement of Positions answers Issue 30.A.ii "No."[916] Google does not oppose the Rate Design Settlement, which assigns 94 percent of the system average increase to LPS and Schedule LLPS.[917]

The Commission should increase Schedule LLPS rates as a subclass of LPS, by the LPS percentage in the Rate Design Settlement.

32. Revenue Apportionment and Implementation (EMM: Jaynes, Lutz, Gunn, Ives; Staff: Lange; Google: Berry; MECG: York; OPC: Nelson; Marke)

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?

Revenue responsibility should be apportioned by the class percentages in the Rate Design Settlement, which allocates the revenue increase by percentages of the system average increase. LPS and LGS receive 94 percent, and the residential class receives 100 percent. SGS and MGS receive 112.44 percent, with any deficiency balanced between them, and the electric vehicle and lighting classes receive 112.50 percent.[918] Those percentages follow the cost studies, Staff prepared no study of its own. The recalculations by MECG's and Staff's witnesses leave the ordering of class returns unchanged.

The Rate Design Settlement Percentages Move LPS and LGS Toward Cost While Holding the Residential Class at the System Average

The Company's study and the non-coincident-peak recalculation by MECG's witness show the same ordering of class returns. On the Company's study of the current classes, LPS earns 14.73 percent and LGS earns 10.08 percent at present rates, while the residential class earns 0.51 percent,

[916] Google Positions at 6.
[917] See Rate Design Settlement at ¶ 11.
[918] Id. at ¶ 2; see also Ex. 33, Jaynes Direct at 48–49.

against a system average of 4.90 percent.[919] MECG's witness recalculated the allocator with non-coincident peaks and found LPS at 13.21 percent, LGS at 9.66 percent, and the residential class at 0.78 percent.[920] "[T]he conclusion does not change."[921]

Staff notes that the Rate Design Settlement departs from the Company's direct case.[922] The Company's direct case, however, recognized that the current allocation departs from cost. The CCOS results "indicate a significant revenue deficiency in the Residential class, which would typically support shifting revenue responsibility between classes to better align revenues with costs."[923] Absent the transitional considerations the Company described, "the Company would have proposed making some alignment moves between classes prioritizing gradualism."[924] The Company and MECG each treat the studies as directional guidance, and their difference was one of application and timing.[925]

Net revenue from large loads benefits the other classes, and Staff's own equal percentage proposal is adjusted for "the offset of new net revenue from large loads."[926] LLPS revenue allocated across the other classes provides "a benefit to all existing rate customers in the form of incremental class revenue."[927] The level of LLPS revenue is addressed in Section I, and how revenue waived under an income-eligible program would be recovered, if the Commission approved one, is addressed in Section IX.

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[919] See Ex. 33, Jaynes Direct at 45, Table 8.
[920] See Ex. 305, York Surrebuttal at 10.
[921] Id. at 10.
[922] See Tr. Vol. 12 at 161:2–8 (Sarah Lange).
[923] Ex. 33, Jaynes Direct at 48.
[924] Id. at 50.
[925] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 15–16; Ex. 305, York Surrebuttal at 15–16.
[926] Ex. 125, Staff Rate Design Report at 4.
[927] Ex. 33, Jaynes Direct at 41.

Staff Prepared No Study of Its Own, and Its Allocator Objections Do Not Change the Ordering of Class Returns

Staff contends that no reliable CCOS study is possible in this case because of the restructuring and the new large loads, and it recommends an equal percentage increase to the classes as currently constituted.[928] A CCOS study, however, informs the Commission's judgment without dictating the result. Chair Hahn asked Mr. Lutz: "In your other experience, where there hasn't been a new class cost of service, how are costs generally allocated amongst the classes?"[929] He answered that "the cost-of-service study is an indicator. It's a guide for the commission to use in setting just and reasonable rates."[930]

The Company has filed a CCOS study in every rate case since 2005.[931] In this case it filed two, one for the current classes and one for the restructured classes.[932] The studies "offer an important data point to inform the Parties about revenue increase allocation."[933]

Staff did not prepare its own CCOS study, as Staff's counsel confirmed to Chair Hahn.[934] Instead, Staff performed a functionalized cost of service study and used it to set the structure and level of individual rate elements.[935] Staff "has not explained why that cost analysis is sufficiently reliable to influence the structure and level of individual rate elements but insufficiently reliable to inform the class revenue apportionment."[936] Asked by Commissioner Coleman, Staff's witness acknowledged that Staff "didn't put the resources into" a CCOS study.[937]

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[928] See Ex. 125, Staff Rate Design Report at 4; Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 33.
[929] Tr. Vol. 12 at 112:7–9 (Chair Hahn).
[930] Tr. Vol. 12 at 112:10–18 (Lutz).
[931] See Ex. 33, Jaynes Direct at 33.
[932] Id. at 45–46.
[933] Ex. 57(HC)/58(P), Lutz Surrebuttal at 22.
[934] See Tr. Vol. 12 at 26:11–16 (Staff counsel).
[935] See Ex. 305, York Surrebuttal at 5–6; Ex. 34(HC)/35(P), Jaynes Rebuttal at 10.
[936] Ex. 305, York Surrebuttal at 6.
[937] Tr. Vol. 12 at 178:5–17 (Sarah Lange).

Staff also contends that the studies overstate the revenue responsibility of the residential, SGS, and MGS classes.[938] In Staff's view, using coincident rather than non-coincident peaks in an average and excess allocator is not consistent with the instructions of the National Association of Regulatory Utility Commissioners ("NARUC").[939] Staff's witness made a similar recalculation with non-coincident peaks and found LPS at 14.10 percent, LGS at 9.68 percent, and the residential class at 0.77 percent. She cautioned, however, that she could not adjust the study for Staff's other concerns.[940] The criticisms raised in rebuttal "identify analytic choices rather than deficiencies in the study, and those choices move the magnitude of a result rather than its direction."[941] Staff also objects that the percentages "result in excessive total revenues when applied to the settled-upon billing determinants."[942] The Rate Design Settlement balances the remaining deficiency between SGS and MGS.[943] MECG's witness had recommended an above-average increase for SGS.[944] The signatories chose those classes to absorb the final adjustments needed to make the revenue precise.[945] Chair Hahn asked whether the dollars produced by the percentages still match the agreement with MECG. Mr. Lutz answered that, "as the commission settles on a final revenue number, the percentages would allow us to track."[946]

OPC's Alternative Allocators Are Addressed Under Issues 32.A.i and 32.A.ii

OPC would base apportionment on a CCOS study using different allocators, and it opposes the shifts among classes.[947] Those allocators are addressed under Issues 32.A.i and 32.A.ii. OPC

[938] See Staff Rate Design Objection at ¶ 6(b).
[939] See Ex. 138, Sarah Lange Rebuttal at 54.
[940] Id. at 33.
[941] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 12.
[942] Staff Rate Design Objection at ¶ 6(a).
[943] See Rate Design Settlement at ¶ 2.
[944] See Ex. 305, York Surrebuttal at 14.
[945] See Tr. Vol. 12 at 106:23–107:10 (Lutz).
[946] Tr. Vol. 12 at 115:1–9 (Lutz)
[947] See Ex. 208, Nelson Direct at 4; Ex. 209, Nelson Surrebuttal at 13; id. at 25; OPC Rate Design Opposition at ¶¶ 1, 3.

also opposes reallocation without the study Staff recommends, which concerns the determinants for calculating the restructured rates and is addressed under Issue 29.A.iv.[948]

The Commission should apportion the revenue increase among the classes by the percentages in the Rate Design Settlement. Those percentages move LPS and LGS toward cost and hold the residential class at the system average. SGS and MGS balance the remaining deficiency.

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?

The Commission need not choose a classification method to decide the apportionment, because the Rate Design Settlement sets class percentages and its signatories did not agree to any cost-of-service methodology.[949] Staff could not adjust the Company's results for the distribution issues it raises.[950] If the Commission reaches the question, it should keep the minimum system method. "[T]he method is a recognized and widely used approach for identifying the customer-related portion of distribution investment."[951] MECG supports it.[952] Staff does not propose eliminating the customer classification of distribution costs. Staff prefers a different method, a zero-intercept study, and its witness described the choice between the two as a matter of opinion.[953] OPC proposes the Basic Customer method, which would treat FERC Accounts 364 through 368 as entirely demand-related.[954] OPC's witness did not establish that the Company's method is unreasonable.[955]

[948] See Staff Rate Design Objection at ¶ 8(d).
[949] See Rate Design Settlement at ¶ 3.
[950] See Ex. 138, Sarah Lange Rebuttal at 48.
[951] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 9.
[952] See Ex. 306, York Rebuttal at 12–13.
[953] See Ex. 36, Jaynes Surrebuttal/True-Up Direct at 9–10; Ex. 138, Sarah Lange Rebuttal at 54.
[954] See Ex. 209, Nelson Surrebuttal at 13, 14.
[955] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 21.

The Commission need not decide how customer-related distribution costs should be classified. If it does, it should accept the Company's minimum system method and reject the Basic Customer method.

ii. What is the appropriate allocation of production-related cost of service for any class cost of service study relied upon in this case?

The Commission need not choose a production allocator either. Staff contends that the Company's use of coincident peaks in its average and excess allocator is inconsistent with the NARUC cost allocation manual.[956] That choice does not change the result. As shown under Issue 32.A, MECG's witness and Staff's witness each recalculated the allocator with non-coincident peaks. Each found LPS and LGS earning well above the system average and the residential class far below it.[957] Staff also contends that the study allocates the costs and the value of renewable generation inconsistently.[958] Staff could not adjust the Company's results for that concern.[959] OPC proposes the probability of dispatch ("POD") method for production and transmission costs.[960] MECG and Google oppose it.[961] Google witness Dr. Carolyn Berry (Partner, Bates White Economic Consulting) opposes it because "[g]eneration and transmission must be built to meet peak demand and capacity needs."[962] OPC's POD allocator is nearly identical to the Company's energy allocator for every class.[963] Staff's witness also considers POD, like the average and excess method, an unreasonable allocator for a utility whose plants dispatch in response to regional market prices.[964]

[956] See Ex. 138, Sarah Lange Rebuttal at 54.
[957] See Ex. 305, York Surrebuttal at 10; Ex. 138, Sarah Lange Rebuttal at 33.
[958] See Ex. 138, Sarah Lange Rebuttal at 30.
[959] Id. at 33.
[960] See Ex. 208, Nelson Direct at 4; id. at 42; Ex. 209, Nelson Surrebuttal at 26.
[961] See Ex. 306, York Rebuttal at 4–11; Ex. 452, Berry Rebuttal at 12–14.
[962] Ex. 452, Berry Rebuttal at 12.
[963] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 12.
[964] See Ex. 138, Sarah Lange Rebuttal at 31.

The Commission need not decide how production costs should be allocated. If it does, it should retain an average and excess allocation and reject the POD method.

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

The rates ordered in this case should reflect affordability through the apportionment and through targeted programs. The Rate Design Settlement holds the residential class at the system average increase.[965] It does so although the Company's study and the recalculations by MECG's and Staff's witnesses show the residential class earning less than 1 percent at present rates, against a system average of 4.90 percent.[966] The Programs Stipulation increases funding for the Economic Relief Program, the Critical Medical Needs Program, and income-eligible weatherization, as discussed under Issue 16.E.[967] "[A] dollar of ratepayer or shareholder investment in a targeted program produces significantly more affordability benefits per dollar spent than across-the-board rate reductions that dilute the benefits among customers who do not face affordability challenges."[968] Targeted programs "achieve the policy goal of supporting vulnerable customers without distorting the cost-of-service framework that the Commission uses to set just and reasonable rates."[969] OPC supports its customer charge waiver program, addressed in Section IX.[970] The LLPS revenue and fuel cost issues are addressed in Section I, and the allocation of CWIP under Issue 32.D.

The Commission should reflect customer affordability through the apportionment in the Rate Design Settlement and the income-eligible programs in the Programs Stipulation while rejecting OPC's recommended customer charge waiver program in this case.

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[965] See Rate Design Settlement at ¶ 2.
[966] See Ex. 33, Jaynes Direct at 45, Table 8; Ex. 305, York Surrebuttal at 10; Ex. 138, Sarah Lange Rebuttal at 33.
[967] See Programs Stipulation at ¶ 2.
[968] Ex. 22, Gunn Rebuttal at 26.
[969] Id. at 26.
[970] See Ex. 204, Marke Surrebuttal at 15.

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

Yes. The Company requests to implement the rate changes by customer billing cycle, applying "ordered rate and class changes based on the customer billing cycle date instead of on one fixed date for everyone."[971] A single fixed date would produce prorated bills, with customers receiving a multi-page bill showing part of their usage at the old rates and the rest at the new rates, and "[a]pplying the changes with the bill cycle would avoid this proration and provide a customer bill more like a normal bill."[972] The approach was used most recently to implement residential time-of-use rates, and the Rate Design Settlement adopts it.[973]

Staff objects that the Company first proposed bill-cycle implementation in surrebuttal, and it contends that no party has had an opportunity to address the proposal's interaction with riders such as the FAC and MEEIA.[974] Staff's testimony on the Rate Design Settlement identified no rider interaction.[975] Staff does not oppose putting the rate increase into effect at the end of the case. Staff would increase the existing rates at that time and put the restructured rates into effect later, in a shoulder month.[976] OPC's opposition to the Rate Design Settlement does not list the implementation term.[977] OPC therefore did not object to that term and has waived its right to a hearing on it.[978]

The Commission should permit the Company to implement the rate increase and the restructured rates by bill cycle.

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[971] Ex. 57(HC)/58(P), Lutz Surrebuttal at 8.
[972] Id. at 8.
[973] See id. at 8; Rate Design Settlement at 1.
[974] See Staff Rate Design Objection at ¶ 7(b).
[975] See Tr. Vol. 12 at 161:1–196:11 (Sarah Lange).
[976] See Tr. Vol. 12 at 163:24–164:17 (Sarah Lange).
[977] See OPC Rate Design Opposition at ¶ 4.
[978] See 20 CSR 4240-2.115(2)(B).

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

Revenue responsibility for CWIP for Mullin Creek No. 2 should be apportioned among all customer classes through the class percentages in the Rate Design Settlement, and none of it should be assigned directly to Schedule LLPS. Mullin Creek No. 2 is a system resource built for every customer, and the revenue requirement associated with its CWIP is part of the increase that the Rate Design Settlement apportions by class percentages. Schedule LLPS, as a subclass of LPS, pays its share through the LPS percentage.[979] The study's allocation of costs and the Rate Design Settlement's allocation of the revenue increase are two different steps, and every class, Schedule LLPS included, pays through the second.

Mullin Creek No. 2 Is a System Resource Whose Cost Every Class Bears

Mullin Creek No. 2 is a system resource. The need for the unit "is based not solely on load growth." It also rests on "recent and future increases in reserve planning margins and other resource adequacy requirements by SPP."[980] Google agrees.[981] Chair Hahn asked Company witness Kevin Gunn (Vice President – Regulatory and Government Affairs) whether any part of the resource would serve large users and whether its cost allocation had been determined, and he answered, "It is a system resource."[982] Asked whether it would be allocated to all customers, he answered, "Correct." The allocation of the plant's costs would be determined in the general rate case after the unit enters service.[983] On recross-examination by OPC, he testified that the resources were planned for organic load growth, SPP reserve margins, and system growth, "not to directly

[979] See Rate Design Settlement at ¶ 2; see also Ex. 33, Jaynes Direct at 48–49; Ex. 34(HC)/35(P), Jaynes Rebuttal at 14.
[980] Ex. 22, Gunn Rebuttal at 22.
[981] See Ex. 453, Berry Surrebuttal at 15.
[982] Tr. Vol. 9 at 97:13–21 (Gunn).
[983] Tr. Vol. 9 at 97:22–98:4 (Gunn).

serve a large load," and that the CWIP impact in this case will be "allocated in this case."[984] Those two answers concern two different amounts. The CWIP revenue requirement in this case is apportioned among all classes by the Rate Design Settlement percentages, and the plant's full cost enters rates in the rate case after the unit is in service. Direct assignment of generation costs to large load customers "would undermine least-cost planning, distort cost-of-service and cost-causation principles, and impair optimized system operations."[985]

Chair Hahn Asked How the CWIP in This Case Would Be Allocated Among the Classes

Chair Hahn explained to Mr. Gunn that she was thinking through how CWIP included in rates in this case would be allocated among the classes, or whether it could be allocated differently.[986] Every class, Schedule LLPS included, pays a share of the CWIP revenue requirement through the Rate Design Settlement's class percentages, as the next two subsections explain.

Every Class, Including Schedule LLPS, Pays a Share of the CWIP Revenue Requirement Through the Rate Design Settlement

Cost allocation and revenue allocation are different steps. The study assigns costs to classes, and rate design decides how much of the increase each class pays. The Rate Design Settlement allocates the revenue increase among the classes by percentages of the system average increase, and it includes Schedule LLPS "as an LPS subclass."[987] LPS receives 94 percent of the system average increase.[988] The revenue requirement for CWIP, $5,691,286 in the Company's request, is part of that increase.[989] Because Schedule LLPS rates rise with LPS rates, Schedule

[984] Tr. Vol. 9 at 99:21–100:4, 101:22–25 (Gunn).
[985] Ex. 22, Gunn Rebuttal at 23.
[986] See Tr. Vol. 9 at 97:25–98:16 (Gunn).
[987] Rate Design Settlement at ¶ 2.
[988] Id. at ¶ 2.
[989] See Staff Reconciliation at 1, line 35.

LLPS customers pay a share of the CWIP revenue requirement, as every other class does. Why Schedule LLPS receives the LPS percentage is addressed under Issue 30.A.ii, and the Company will maintain that relationship until operational data supports a comprehensive cost allocation.[990]

The Study Allocates No CWIP to Schedule LLPS Because the Test Year Had No LLPS Load

The Company's class cost of service study allocates none of the $64,389,129 of CWIP for Mullin Creek No. 2 in its true-up rate base to Schedule LLPS.[991] The study allocates CWIP consistently with other production-demand plant, using the average and excess method with a four coincident peak component.[992] Because the study assigns the LLPS subclass no demand-related costs, none of the CWIP reaches Schedule LLPS.[993] For presentation purposes, the study includes the LLPS subclass within the LPS class.[994] That is a deliberate choice for a transitional test year. Because no LLPS customer was active during the test year, the study represents the subclass with a proxy customer modeled on the first anticipated LLPS customer.[995] The study assigns the subclass its portion of variable fuel costs but not embedded demand-related costs, because the expected level of LLPS demand was still uncertain.[996] The Company believes it should "observe actual coincident and non-coincident peak demand levels for an entire 12-month test period before assigning the appropriate level of cost responsibility."[997] OPC and Staff describe the study the same way. OPC witness Ron Nelson (Founding Partner, Current Energy Group) states that, because there was no Schedule LLPS demand or energy use in the test year, "this allocation method

[990] See Ex. 33, Jaynes Direct at 48.
[991] See Ex. 43, Klote Surrebuttal/True-Up Direct, Sch. RAK-7, line 22; Ex. 175, Young True-Up Rebuttal at 2; Ex. 208, Nelson Direct at 20–21.
[992] See Ex. 33, Jaynes Direct at 37; Ex. 34(HC)/35(P), Jaynes Rebuttal at 14.
[993] See Ex. 33, Jaynes Direct at 40; Ex. 34(HC)/35(P), Jaynes Rebuttal at 16.
[994] See Ex. 33, Jaynes Direct at 40.
[995] Id. at 39; Ex. 36, Jaynes Surrebuttal/True-Up Direct at 5–6.
[996] See Ex. 33, Jaynes Direct at 40.
[997] Id. at 40.

does not allocate any costs to this rate schedule."[998] Staff's witness states that the study did not allocate fixed costs to LLPS customers, and that this "is not the measure of whether LLPS rates are adequate."[999] The Company did not use the study to set class revenues either, because the Company "did not rely on the CCOS to propose large class revenue shifts in this case."[1000] OPC's conclusion that "every customer class except Schedule LLPS will carry the burden of paying these costs" therefore confuses the study's cost allocation with the Rate Design Settlement's revenue allocation, under which Schedule LLPS shares that burden.[1001]

The Large Load Order Contemplates an LLPS Revenue Offset to CWIP, and This Case Applies It

The Commission has already addressed how CWIP for new generation and Schedule LLPS revenues fit together. In the Large Load Order, it found that if dollars from existing customers were collected through CWIP, those dollars "could be directly offset by revenues collected from any LLPS customers receiving service."[1002] It then held that "[a]ny treatment of revenues from LLPS customers will be determined in a future rate case where those revenues would be known and measurable."[1003] That framework proceeds in two steps, and this case takes the first. The LLPS Stipulation reflects $60 million of LLPS revenue in the revenue requirement, the annualized value of the known and measurable billing determinants at the true-up, as Section I explains. That revenue reduces the increase every class pays, and it is more than ten times the $5,691,286 revenue requirement for CWIP.[1004] The second step waits for load. The LLPS Stipulation calls this case "transitional" because no 75 MW LLPS customer is reflected in the test year.[1005] LLPS load added

[998] Ex. 208, Nelson Direct at 21.
[999] Ex. 138, Sarah Lange Rebuttal at 16.
[1000] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 21.
[1001] Ex. 208, Nelson Direct at 21.
[1002] See Large Load Order at 43 (Finding of Fact 100). The Chair concurred in the order. Id. at 46.
[1003] Id. at 44.
[1004] See LLPS Stipulation at ¶ 13; Staff Reconciliation at 1, line 35.
[1005] LLPS Stipulation at ¶ 1.

after the true-up, and the revenue it produces, will be known and measurable in a later rate case. Until then, the ERS shares LLPS-driven earnings with customers, as Section I explains. The Large Load Order found that the Commission could approve an earnings-sharing mechanism "in a future rate case after LLPS customers begin receiving service in Missouri."[1006]

OPC's Front-End Direct Assignment Has No Basis in the Study or the Large Load Order, and Staff Finds It Unnecessary to Address

OPC requests that the Commission assign CWIP "entirely to the LLPS customer class" and collect it "on the front-end."[1007] OPC's stated purpose is to minimize "investor and legacy ratepayer stranded asset risk."[1008] The Commission addressed that risk when it approved Schedule LLPS. It found that the minimum bill commitments and credit standards "reduce stranded cost and cross subsidy risks."[1009] It also found that the collateral and exit-fee requirements protect other ratepayers if a large load customer terminates its service agreement early.[1010]

OPC's direct assignment would set the Large Load Order's framework aside in a test year in which Schedule LLPS had no load to which any cost could be allocated. Google's witness observes that OPC "provides no evidence with respect to Mullin Creek #2."[1011] Google would allocate any approved CWIP by the average and excess four coincident peak method, and it requests that the Commission reject OPC's proposal.[1012] Staff's position is that, because it recommends equal percentage increases to all classes, including Schedule LLPS, "it is not necessary to address this issue."[1013]

[1006] Large Load Order at 43 (Finding of Fact 102).
[1007] OPC Positions at 15.
[1008] Id.
[1009] Large Load Order at 17 (Finding of Fact 38).
[1010] See id. (Finding of Fact 36).
[1011] Ex. 453, Berry Surrebuttal at 14–15.
[1012] Id. at 15–16; id. at 16.
[1013] Staff Positions at 35.

The Commission should apportion the revenue requirement for CWIP for Mullin Creek No. 2 among all customer classes through the class percentages in the Rate Design Settlement, under which Schedule LLPS pays the LPS percentage. It should reject OPC's direct assignment of that CWIP to Schedule LLPS.

33. Critical Peak Rate (EMM: Jaynes, Lutz; Staff: Lange)

A. Should the Critical Peak Rate recommended by Staff be implemented?

No. Staff requests that the Commission order the Company to implement a CPR tariff that would not apply to service before November 1, 2027. A CPR event would occur when the day-ahead locational marginal price exceeds $100 in each hour of one operating day and is $100 or more in each hour of the next. Staff offers two options: the first charges $0.10 per kWh for the six consecutive hours with the highest day-ahead prices on the event day, and the second charges $0.025 per kWh for the whole day.[1014] MECG opposes the CPR.[1015] Staff has not shown that the CPR would benefit customers, its design remains undeveloped, and the Company's time-based rates are voluntary for good reason. In fact, Staff's proposal would add an additional burden on customers at the exact time when they are already experiencing larger energy usage and therefore higher costs.

Staff Has Not Shown a Benefit

Staff has not shown that the CPR would produce a measurable benefit. Staff explains that the CPR should not be offered as a MEEIA program because "there is no reasonable or reliable way to quantify, evaluate, or verify the amounts of energy expense avoided or sales avoided."[1016] Staff also told MECG that "[i]t is not possible to estimate the aggregate revenue that would be

[1014] See Ex. 125, Staff Rate Design Report at 40; id. at 41; id. at 42; id. at 44; Ex. 167, Sarah Lange Surrebuttal/True-Up Direct at 45.
[1015] See Ex. 305, York Surrebuttal at 36.
[1016] Ex. 125, Staff Rate Design Report at 41 n.36.

produced."[1017] Staff's witness agreed that Staff does not know how much revenue the CPR would produce, and Staff did no customer surveys.[1018] Staff's witness does not expect the program at this launch to "cause massive conservation because frankly, I . . . don't think that . . . that's really the target of this." The target "is to improve the customer understanding of what's happening in the wholesale market" and to give customers an economic signal.[1019] Without quantification, "it is difficult to conclude that the proposed CPR will produce benefits sufficient to justify the customer impact, operational complexity, communication burden, and weather-event surcharge optics."[1020]

The CPR would also be mandatory.[1021] Staff's witness agreed that it would apply to every customer not specifically exempted, including hospitals and municipalities.[1022] Staff would exempt four groups: critical medical needs customers, customers with registered medical equipment, Economic Relief Pilot Program customers, and income-eligible customers.[1023] Staff "did not attempt to identify exemption categories for non-residential customers."[1024] During severe weather, "a portion of customer usage is not discretionary. A surcharge during those conditions risks charging customers more at the same time electricity may be most essential."[1025] Staff "has not performed a detailed analysis" of the effect on non-residential customers, citing the range of their sizes and usage. Its illustrations assume Option 2 and no change in usage. On those assumptions, a large general service customer using about 1,000 kWh a day would pay about $25

[1017] Ex. 305, York Surrebuttal, Sch. JAY-SUR-1 at 13 (Staff response to MECG Data Request 0533).
[1018] See Tr. Vol. 9 at 17:12–18:2, 18:8–13 (Sarah Lange).
[1019] Tr. Vol. 9 at 31:19–32:2 (Sarah Lange).
[1020] Ex. 34(HC)/35(P), Jaynes Rebuttal at 39.
[1021] Unlike its namesake, this CPR would be administered whether or not the patient needs it.
[1022] See Tr. Vol. 9 at 16:10–17:11 (Sarah Lange).
[1023] See Ex. 125, Staff Rate Design Report at 47.
[1024] Ex. 305, York Surrebuttal, Sch. JAY-SUR-1 at 16 (Staff response to MECG Data Request 0535).
[1025] Ex. 34(HC)/35(P), Jaynes Rebuttal at 39.

more per event day. A large power customer using about 100,000 kWh a day would pay about $2,500 more.[1026]

The price signal also arrives late. Staff acknowledges that under Option 1 the event-hour information "may not be available to customers until nearly midnight of the preceding day."[1027] The Company would have to check day-ahead prices and make a notification decision every day of the year, with less than 24 hours to notify customers of each event.[1028] Staff did not perform a specific analysis of whether commercial and industrial customers could shift or curtail usage on that notice.[1029] The Company describes the CPR as a surcharge during severe weather events,[1030] but its reach is broader. Staff's witness agreed that the CPR's trigger is energy pricing and that it would apply in summer as well as winter.[1031] Asked whether it would also apply if regional plant outages raised day-ahead prices, she answered, "[T]he trigger on this is not weather. The trigger on this, as we've drafted it, is energy pricing."[1032] Customers could therefore pay the charge during price events that have nothing to do with weather. In addition, if the CPR occurs during extreme weather events, no price signal may make a difference and the Commission may not want to discourage energy use at that time.

The Design Is Not Developed

The design has changed since Staff filed it. In rebuttal, Staff added a charge of $3.00 per event day for residential customers who have opted out of advanced metering, because its witness had "overlooked the ability of residential customers to avoid AMI metering."[1033] Staff's witness

[1026] Ex. 305, York Surrebuttal, Sch. JAY-SUR-1 at 13 (Staff response to MECG Data Request 0533).
[1027] Ex. 125, Staff Rate Design Report at 45.
[1028] See Ex. 55(HC)/56(P), Lutz Rebuttal at 65.
[1029] See Ex. 305, York Surrebuttal, Sch. JAY-SUR-1 at 16 (Staff response to MECG Data Request 0535).
[1030] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 38.
[1031] See Tr. Vol. 9 at 24:1–14 (Sarah Lange).
[1032] Tr. Vol. 9 at 24:12–14 (Sarah Lange).
[1033] Ex. 138, Sarah Lange Rebuttal at 29.

agreed that hospitals, natural gas facilities, and nursing homes could reasonably be excluded, and she suggested that the details could be worked out later in a workshop or a non-contested docket.[1034] Staff's proposal is, in its witness's own description, "a very bare bones recommendation."[1035] "[T]he commission can make this as complex as they feel is necessary," and "[w]e're limited only by our creativity on this."[1036] Asked how customers would be given notice of an event, Staff answered that it was "open to deferring to the company's management on how to best administer this program."[1037] The AMI opt-out addition "further highlights that the design has not been sufficiently developed."[1038]

Time-Based Pricing Should Remain Voluntary

The Company's approach to time-based pricing is voluntary. The Company recently changed its residential tariffs so that customers may opt out of time-of-use rates.[1039] Its optional time-of-use rate for non-residential customers "preserves customer choice without imposing the structure on customers that cannot respond."[1040] In 2025, the General Assembly directed the Commission to allow customers on mandatory residential time-of-use rates ordered before August 28, 2025, to opt out.[1041] That legislation shows that "mandatory time-based rates are discouraged."[1042]

Staff stresses that the CPR is revenue neutral to the Company.[1043] The Company's objections, however, have nothing to do with earnings and concern customer impact,

[1034] See Tr. Vol. 9 at 30:13–31:10, 25:14–18, 26:19–27:3 (Sarah Lange).
[1035] Tr. Vol. 9 at 38:14–15 (Sarah Lange).
[1036] Tr. Vol. 9 at 26:19–27:3 (Sarah Lange).
[1037] Tr. Vol. 9 at 23:8–25 (Sarah Lange).
[1038] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 23–24.
[1039] See Ex. 54, Lutz Direct at 30 n.20.
[1040] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 17.
[1041] See Section 386.1100.
[1042] Ex. 55(HC)/56(P), Lutz Rebuttal at 63.
[1043] See Tr. Vol. 9 at 38:24–25, 29:10–16 (Sarah Lange).

administration, and the absence of any demonstrated benefit.[1044] Without the CPR, the costs would be recovered from customers through the FAC, subject to its sharing mechanism and potentially from different customers, as Staff's witness acknowledged.[1045] A charge that moves the same costs among customers, with no measured change in usage, is not a benefit. Staff also notes that the Company's consultant, The Brattle Group, evaluated critical peak pricing.[1046] Brattle surveyed 74 commercial and industrial rates, found one with critical peak pricing, and did not shortlist critical peak pricing among its six options.[1047] Staff did not discuss the CPR with the Company before it appeared in Staff's testimony.[1048] Staff's witness could not recall a critical peak rate ever coming before the Commission in a rate case.[1049] Any critical peak design "should be developed through a more complete process that evaluates costs, benefits, customer impacts, operational feasibility, and alternatives such as voluntary demand response or rebate-based programs."[1050]

The Commission should not order the Company to implement Staff's proposed CPR.

i. If not implemented, are other accommodations needed to address high market cost events and establish offsetting revenues to be applied through the FAC?

No. The Partial Stipulation adds language to the Company's FAC tariff "addressing the recovery of extraordinary events."[1051] That language is Staff's own proposal, offered "to mitigate potential large rate shock for customers" after a major winter storm.[1052] After an extraordinary event, for good cause shown and after an opportunity for any party to be heard, the Commission

[1044] See Ex. 34(HC)/35(P), Jaynes Rebuttal at 39; Ex. 55(HC)/56(P), Lutz Rebuttal at 64–66.
[1045] See Tr. Vol. 9 at 39:10–23 (Sarah Lange).
[1046] See Tr. Vol. 9 at 18:14–21 (Sarah Lange).
[1047] See Ex. 33, Jaynes Direct, Sch. GAJ-04 at 12–16.
[1048] See Ex. 55(HC)/56(P), Lutz Rebuttal at 61.
[1049] See Tr. Vol. 9 at 19:7–12 (Sarah Lange).
[1050] Ex. 36, Jaynes Surrebuttal/True-Up Direct at 24.
[1051] Partial Stipulation at ¶ 15; id. at 14.
[1052] See Ex. 106, Henderson Direct at 8.

may extend recovery beyond twelve months over a period it sets.[1053] Addressing extraordinary events in the FAC is "a reasonable policy objective."[1054] The CPR's aim of mitigating FAC impacts aligns with Staff's own extraordinary-event recommendation, as Staff's witness acknowledged. [1055] Other tools can address high-cost events, including deferrals and securitization.[1056] Staff criticizes recovery through the FAC or a securitization charge because it pushes the cost months or years past the event.[1057] The stipulated language, however, leaves the length of any extended recovery to the Commission, event by event, on a showing of good cause.

The Commission should order no accommodation beyond the extraordinary-event language in the Partial Stipulation.

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

No. Staff would add a line titled "Critical Peak Rate Revenue" to the Company's fuel adjustment rate tariff sheet, under which CPR revenues would accumulate and be "distributed and socialized to all customers" in the Company's next fuel adjustment rate filing.[1058] The line serves no purpose without the CPR, and the Company's proposed FAC tariff sheets have no such line.[1059] "[B]ecause the proposal itself has not been shown to be reasonable, necessary, or beneficial to customers, any discussion regarding its potential impact on the FAC is speculative and premature."[1060]

The Commission should not order a separate line on the Company's fuel adjustment rate tariff for critical peak pricing.

[1053] See id.
[1054] Ex. 72, Nunn Rebuttal at 17.
[1055] See Tr. Vol. 9 at 32:3–18 (Sarah Lange).
[1056] See Ex. 55(HC)/56(P), Lutz Rebuttal at 66.
[1057] See Tr. Vol. 9 at 24:15–25:2, 26:4–7, 33:17–24 (Sarah Lange).
[1058] Ex. 125, Staff Rate Design Report at 48, 49.
[1059] See Ex. 73, Nunn Surrebuttal/True-Up Direct, Sch. LJN-8 (5th Revised Sheet No. 50.10).
[1060] Ex. 72, Nunn Rebuttal at 13.

XI. TRACKERS

The Company respectfully requests that the Commission approve its proposed tracker for critical infrastructure protection ("CIP") and cyber security costs because those costs are difficult to estimate from a historical test year.

36. Critical Infrastructure Protection and Cyber Security (EMM: Klote, Gunn, Charles King; Staff: Lyons; OPC: Schaben)

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

The revenue requirement should include the test-year level of CIP and cyber security operations and maintenance ("O&M") expense.[1061] Staff agrees that the Company "supports a level of these costs based on the test year period, 12-months ending June 30, 2025,"[1062] and neither Staff nor the Company adjusted the costs from the test-year amount.[1063] Staff corrected the test-year level in its rebuttal testimony to $4,491,745 on a total-company basis.[1064] Staff's errata confirms the correction.[1065] The Company accepts that corrected level.

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

Yes. The Commission should approve a tracker for incremental CIP and cyber security O&M costs, measured against the test-year base level.[1066] Staff and OPC oppose the tracker, Staff because the costs "are flat" and OPC because forecasted costs "are not volatile."[1067] The tracker is warranted because CIP and cyber security costs are driven by mandates, threats, and third-party events that a historical test year cannot forecast, because the tracker satisfies the criteria OPC's own witness identifies, and because its design protects customers.

[1061] See Ex. 140, Lyons Rebuttal at 11; Ex. 41, Klote Direct at 36.
[1062] Ex. 140, Lyons Rebuttal at 11.
[1063] See Ex. 168, Majors Surrebuttal/True-Up Direct at 15.
[1064] See Tr. Vol. 11 at 17:18–18:2 (Lyons); Ex. 140, Lyons Rebuttal at 10–11.
[1065] See Staff's errata to Lyons Rebuttal (Oct. 14, 2026).
[1066] See Ex. 41, Klote Direct at 34–36.
[1067] Ex. 140, Lyons Rebuttal at 11; Ex. 217, Schaben Direct at 7.

CIP and Cyber Security Costs Cannot Be Forecast From a Historical Test Year

The Company must respond to evolving cyber threats and comply with changing federal reliability and cyber security requirements, including the CIP standards. Those requirements "can result in significant and unpredictable costs that are largely outside of the Company's control."[1068] Historical averages "do not fully capture future compliance obligations, emerging threat activity, or the need to respond efficiently and quickly to material cybersecurity events."[1069] Third-party events are one example. In the CrowdStrike outage, "a third-party issued software update, rather than a cyberattack, caused widespread disruption," and the Company "cannot reasonably predict the timing, scope, or cost of similar vendor-driven events during a historical test year."[1070] OPC witness Angela Schaben (Utility Regulatory Auditor) acknowledges that "[a]ttempting to predict these events a year in advance when devising a cybersecurity budget is infeasible."[1071]

The Company acknowledges that "there have been no serious cybersecurity events in recent years internal to Evergy." However, "the Company should not be expected to budget for unpredictable, incremental costs that may not be reasonably predictable in a historical test year."[1072] Staff and OPC note that the Company's spending has been relatively stable.[1073] A stable history is not a predictor of a stable future, and the way the Company buys security is also changing. "Most security tools are now subscription based which makes them an O&M charge."[1074] The move to subscription services is "applying additional pressure on year over year

[1068] Ex. 42, Klote Rebuttal at 32–33.
[1069] Ex. 40, King Rebuttal at 3.
[1070] Id. at 5.
[1071] Ex. 219, Schaben Surrebuttal at 28.
[1072] Ex. 40, King Rebuttal at 3.
[1073] See Ex. 140, Lyons Rebuttal at 11; Ex. 219, Schaben Surrebuttal at 23–24.
[1074] Ex. 39, Johnson Direct at 3 (adopted by Mr. King; Tr. Vol. 11 at 14:3–10 (King)).

O&M expenses."[1075] The tracker permits the Company to respond to these events and pressures when they occur.[1076]

Attackers' Use of Artificial Intelligence Makes These Costs Harder to Predict

The Company's witnesses testified to a newer source of uncertainty, the use of artificial intelligence ("AI") by attackers. Mr. King, the Company's Chief Technology Officer, adopted direct testimony stating that "[a]ttackers are using AI enhanced tools to focus attacks on users with privileged credentials."[1077] An attacker who obtains those credentials "can often further expand that access into critical parts of an environment." That access "can lead to customer data exposure and the potential of cyber caused outages to the [grid]."[1078] Mr. King testified that the capabilities of AI models "in the hands of cyber threat actors pose an unpredictable yet significant risk to any entity."[1079] For critical infrastructure, he testified, the dynamic nature of these risks poses "the very type of disruption and cost that fall under this category of events."[1080]

Mr. King also testified that "the baseline of information security risk is higher today than ever before" and that the Company "expects security threat costs to have a rising impact on the Company over time."[1081] OPC witness Dr. Geoff Marke agrees: "Both physical and cyber security concerns have grown since I last filed testimony."[1082]

Ms. Schaben calls these "hypothetical AI threats."[1083] They are not hypothetical. The testimony Mr. King adopted states that attackers are using AI-enhanced tools against users with

[1075] Ex. 40, King Rebuttal at 3–4.
[1076] See Ex. 41, Klote Direct at 34.
[1077] Ex. 39, Johnson Direct at 5 (adopted by Mr. King).
[1078] Id.
[1079] Ex. 40, King Rebuttal at 4.
[1080] Id.
[1081] Id. at 6.
[1082] Ex. 202, Marke Direct at 18.
[1083] Ex. 219, Schaben Surrebuttal at 29.

privileged credentials.[1084] Ms. Schaben does not address that testimony. Her response addresses only Mr. King's example of AI models escaping a test environment, which she ties to a report titled "Autonomous Sandbox Escape: OpenAI Models Breach Hugging Face." She treats that event as isolated but agrees that it "occurred."[1085]

The Tracker Satisfies the Criteria OPC's Witness Identifies and Staff's Own Tracker Policy

OPC lists five criteria for a tracker: materiality, volatility, limited management control, verifiability, and balance.[1086] "[T]he proposed tracker satisfies each of the characteristics Ms. Schaben identifies."[1087] Staff's policy likewise recognizes trackers for costs that fluctuate significantly "and for which accurate estimation is difficult."[1088] CIP and cyber security costs are difficult to estimate from a historical test year.[1089] OPC relies on an order in which the Commission found that transmission costs for which the utilities sought an accounting authority order ("AAO") were not "an unusual and infrequent occurrence."[1090] OPC acknowledges, however, that the Commission has approved deferral accounting, "by use of a tracker or an AAO," for costs resulting from "new legislation or rules."[1091] The Company's forecasts do not include new mandates until they are enacted and required of the Company.[1092]

The Tracker Preserves Management Incentives and Protects Customers

OPC contends that a tracker would "eradicate management incentives to achieve compliance through the implementation of cost-effective solutions."[1093] OPC acknowledges,

[1084] See Ex. 39, Johnson Direct at 5 (adopted by Mr. King).
[1085] Ex. 219, Schaben Surrebuttal at 29 & n.69.
[1086] See Ex. 217, Schaben Direct at 5–6.
[1087] Ex. 42, Klote Rebuttal at 32; id. at 33.
[1088] Ex. 140, Lyons Rebuttal at 3.
[1089] See Ex. 40, King Rebuttal at 3, 5.
[1090] See Report & Order at 10, In re Kansas City Power & Light Co. & KCP&L Greater Missouri Operations Co. Accounting Authority Order Application, No. EU-2014-0077 (July 30, 2014); Ex. 217, Schaben Direct at 3.
[1091] Ex. 217, Schaben Direct at 3.
[1092] See Ex. 40, King Rebuttal at 5.
[1093] Ex. 217, Schaben Direct at 8.

however, that "many costs associated with following its obligation to comply with Federal and State regulations is beyond utility control."[1094] The tracker also protects customers, because it "reconciles amounts collected with the Company's actual prudently incurred cybersecurity costs. As a result, the Company cannot recover more than its actual eligible costs, and those costs remain subject to Commission review."[1095] The tracker excludes internal labor costs.[1096] The tracker uses the cost definition that Kansas regulators approved for Evergy Kansas Metro and Evergy Kansas Central.[1097] The tracker terminates upon completion of the first general rate case the Company files on or after January 1, 2031, and the Company would bear the burden of showing that any extension is in the public interest.[1098]

The Commission should approve the CIP and cyber security tracker.

XII. DEPRECIATION

17. Depreciation (EMM: Spanos, Kopp; MECG: Andrews; Staff: Arandia)

A. Which depreciation rates should be used?

The Commission should use the depreciation rates in corrected Exhibit C to the Partial Stipulation, excluding MECG witness Brian Andrews's (consultant, Brubaker & Associates, Inc.) retirement-date adjustments. Exhibit C's depreciation rates are based on the rates proposed and used in Staff's true-up model.[1099] Staff and the Company filed corrected depreciation rates for Exhibit C.[1100] MECG does not oppose the Partial Stipulation, except that it preserved for hearing Mr. Andrews's life estimate adjustments.[1101]

[1094] Id. at 8.
[1095] Ex. 42, Klote Rebuttal at 33.
[1096] See Ex. 41, Klote Direct at 35.
[1097] Id. at 35–36; Ex. 40, King Rebuttal at 7.
[1098] See Ex. 41, Klote Direct at 36.
[1099] See Partial Stipulation at ¶ 12.
[1100] See Notice of Depreciation and Amortization Rates at ¶ 2 (Oct. 13, 2026).
[1101] See Partial Stipulation at 1.

MECG requests the Commission to require that the depreciation expense and rates "take into account the updated probable retirement dates for Iatan Unit 1 and La Cygne Unit 2."[1102] Mr. Andrews would move both units, and La Cygne Common, from March 2040 to June 2045.[1103] He estimated that the change would reduce the Company's originally proposed depreciation expense by about $7.3 million a year.[1104]

However, Staff and the Company both used March 2040 for these units. The Company's study uses a probable retirement date of March 2040 for each.[1105] Staff's depreciation witness, Amanda Arandia, "utilized the anticipated retirement dates from Mr. Spanos' depreciation study."[1106] Company witness John Spanos (President, Gannett Fleming Valuation and Rate Consultants, LLC), whose study Staff used, agrees that "Staff is not proposing any changes to the retirement dates of any of the Company's production facilities."[1107] Staff asks the Commission to reject Mr. Andrews's retirement dates.[1108]

The probable retirement years rest on life spans for each facility that "are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities." Because most of those retirement years lie far in the future, "the retirements of these facilities are not yet subject to specific management plans." "At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed, and the results incorporated in the estimation of the facility's life span."[1109] The Company's

[1102] MECG Response at ¶ 5.
[1103] See Ex. 300, Andrews Direct at 28.
[1104] See id. at 28.
[1105] See Ex. 300, Andrews Direct at 28.
[1106] Ex. 100, Arandia Direct at 4 n.2.
[1107] Ex. 80, Spanos Rebuttal at 16.
[1108] See Tr. Vol. 12 at 34:17–35:2 (Staff counsel).
[1109] Ex. 80, Spanos Rebuttal at 15–16.

depreciation study drew on field reviews and on discussions with Company personnel about "the Company's assets and plans for the assets."[1110]

Mr. Andrews relies on the Company's 2026 Integrated Resource Plan ("IRP") Annual Update, which "no longer projects the retirement of either Iatan Unit 1 or La Cygne Unit 2 within its planning horizon."[1111] The Company does not dispute that. The units' retirement is estimated to occur outside the IRP's scope, which ends in 2045, and the 2026 IRP was not available when the study's rates were calculated.[1112] The 2026 IRP lists no retirement dates for either unit. Mr. Andrews used its final planning year as the retirement date, without discussions with Company personnel or other factors.[1113]

Moreover, "[p]robable retirement dates should not be determined based strictly on a company's IRP." "The IRP is only one of those factors and does not consider all the necessary information to establish a probable retirement date in a Depreciation Study."[1114] The Company drew the same distinction for Wolf Creek: long-term planning analyses "evaluate multiple potential futures and alternative scenarios," while depreciation studies require "supportable estimates for regulatory accounting purposes based upon current facts and circumstances."[1115] The Commission fixes depreciation rates "from time to time" by order.[1116] A supported change in these units' lives can be reflected when the Commission next sets the Company's depreciation rates.

[1110] Id. at 9–10; see Ex. 79, Spanos Direct at 10.
[1111] Ex. 300, Andrews Direct at 29.
[1112] See Ex. 80, Spanos Rebuttal at 17, 18.
[1113] See id. at 18.
[1114] Id. at 17.
[1115] Ex. 30, Ives Rebuttal at 27.
[1116] Section 393.240.2.

Mr. Andrews moved La Cygne Common with La Cygne Unit 2.[1117] MECG's response names only Iatan Unit 1 and La Cygne Unit 2.[1118] To the extent Mr. Andrews's La Cygne Common adjustment remains at issue, it fails for the same reasons.

For these reasons, the Commission should approve the depreciation rates in corrected Exhibit C to the Partial Stipulation. It should approve the rates for Iatan Unit 1, La Cygne Unit 2, and La Cygne Common without Mr. Andrews's retirement-date adjustments.

CONCLUSION

If approved, the $88.9 million increase in the revenue requirement would result in a cumulative 9.6% change since the end of 2017, equal to a 2.3% annual increase since the 2022 rate case and a 1.0% annual increase since 2017.[1119] This is well below regional peer utilities and far below inflation over the same periods.

WHEREFORE, Evergy Metro, Inc. d/b/a Evergy Missouri Metro respectfully requests that the Commission issue a Report and Order that:

1. treats the Pensions Stipulation and the Non-C&I Rate Design Stipulation as unanimous and approves them without modifications or conditions;
2. approves the Partial Stipulation, including Exhibit C as corrected, and the Programs Stipulation without modifications or conditions;
3. finds that the approved terms of those four agreements are reasonable resolutions of the issues that each addresses and will produce just and reasonable rates;
4. approves the LLPS Stipulation and the Rate Design Settlement without modifications or conditions;

[1117] See Ex. 300, Andrews Direct at 28.
[1118] See MECG Response at ¶ 5.
[1119] See supra notes 8–9.

5. adopts the Company's position on each other contested issue, as set forth in this Brief, including Section C of the Introduction and Appendix A;

6. directs the parties to file without delay a joint reconciliation of the revenue requirement that reflects the Commission's decisions;

7. directs the Company to file without delay compliance tariff sheets consistent with that reconciliation;

8. directs the Company to update its MEEIA net margin rates and file them with its compliance tariff sheets; and

9. grants all other relief the Commission deems just and proper.

Respectfully submitted,

/s/ Roger W. Steiner

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by electronic mail, hand delivery, or U.S. Mail, postage prepaid, on all counsel of record on this 6th day of November, 2026.

/s/ Roger W. Steiner
Roger W. Steiner

APPENDIX A: ISSUES AND REQUESTED FINDINGS

This Appendix covers each agreement the Company asks the Commission to approve and each issue on the Amended Joint List. For each, it identifies the part of this Brief that addresses it, the positions the other parties have stated, and the finding the Company requests.[1120]

Issue	Positions of Other Parties	Finding the Company Requests
Introduction and Issues Roadmap, Section A: Stipulations and Agreements		
Pensions Stipulation (pension and other post-employment benefit costs) Introduction, Section A	No party objected.	Treat as unanimous and approve without modifications or conditions.
Non-C&I Rate Design Stipulation (Issues 2.xiii–xiv, 28.A, 29.C) Introduction, Section A	No party objected.	Treat as unanimous and approve without modifications or conditions.
Partial Stipulation (each issue it lists) Introduction, Section A	MECG: objects only as to the life estimate adjustments of its witness, Brian Andrews, reserved under Issue 17.A.	Approve it, with Exhibit C as corrected, without modifications or conditions.
Programs Stipulation (Issues 16, 38–41) Introduction, Section A	OPC: objects only as to Issue 16.E.	Approve it without modifications or conditions.

[1120] The positions shown are those stated in the parties' prefiled testimony, in their statements of positions, in the agreements, and in the parties' objections and responses to the agreements. A party is listed only for an issue on which it stated a position. Each "Value" shown is the value that the Staff Reconciliation, filed September 22, 2026, before any of the agreements, lists for the position shown. Values in parentheses are negative. This Appendix omits citations to sources that the part of this Brief listed for an issue already cites.

Issue	Positions of Other Parties	Finding the Company Requests
23.A Southwest Power Pool transmission costs in the FAC Introduction, Section A	Staff: 31.8 percent. OPC: does not oppose the LLPS Stipulation's use of 31.8 percent.	A pass-through percentage of 31.8 percent.
29.A, 29.A.i Restructuring and time-related periods Introduction, Section A	Staff: does not object to the restructuring, the energy time periods, or a winter on-peak demand period beginning at 7:00 a.m. OPC: its opposition does not list these terms, although it opposes the demand thresholds and 15-minute billing demand, which this Brief addresses under Issue 29.A.iii.	Eliminate the Hours Use rate structure and adopt the Company's periods, with a winter on-peak demand period of 7:00 a.m. to 7:00 p.m.
Section I: Large Load Power Service Issues[1121]		
3.A, 3.A.i LLPS revenues[1122]	Staff: objects to the stipulated LLPS revenues and kWh. OPC: $117 million. MECG: $25 million, with a regulatory liability for net revenues above that amount.	$60 million in LLPS revenues, as Paragraph 13 of the LLPS Stipulation provides, stated at the Schedule LLPS rates in effect at the June 30, 2026 true-up. Any increase in Schedule LLPS rates applied once, in rate design, without a gross-up of that revenue.
31.A LLPS tariff	Staff: clarifications concerning construction power, contract demand exceedance, and the minimum bill calculation. OPC: a 90 percent minimum bill, a twenty-year term, a 25 MW threshold, and an optional Community Benefits Rider.	The Paragraph 4 clarification of the Minimum Monthly Bill, with the tariff redlines Paragraph 5 provides, and no other change to Schedule LLPS. Under it, billing demand is the higher of measured demand or 80 percent of annual Contract Capacity, and energy-based charges are billed in addition.

[1121] In this Section and Section II, each finding the Company requests are grounded in the terms of the LLPS Stipulation, with three exceptions. The exceptions are the findings on Issues 31.B and 25.B and the part of the finding on Issue 31.A that concerns other changes to Schedule LLPS. Google signed the LLPS Stipulation. Staff and OPC object to it, and MECG objected to the extent necessary to preserve its positions for briefing. See LLPS Stipulation at ¶¶ 3–13; id. at 4–5; Staff LLPS Objection at ¶ 3; OPC LLPS Opposition at 3; MECG Response at ¶ 2.

[1122] See Ex. 304, Meyer Surrebuttal at 5, 6; Ex. 301, Meyer Direct at 10.

Issue	Positions of Other Parties	Finding the Company Requests
31.B Large load reporting	Staff: an annual compliance report and delivery of executed LLPS agreements with related information. OPC: independent power usage, water usage, and harmonic distortion studies.	No new reporting requirements beyond the Annual Reports provision in the Global Stipulation.
25.A, 25.C FAC treatment of LLPS customers[1123]	Staff: two options, one keeping LLPS customers in the FAC and one removing them. OPC: remove LLPS customers from the FAC or establish a separate LLPS base factor. Google: no separate LLPS base factor.	LLPS customers remain in the Company's single FAC, subject only to Paragraphs 6 through 10 of the LLPS Stipulation, with no separate base factor. LLPS fuel costs are excluded from the base factor and recovered through the FAC as actual net energy costs.
25.B FAC reporting[1124]	Staff: monthly LLPS energy, demand, and Southwest Power Pool charge reporting, and other reporting. OPC: the additional FAC reporting Staff sponsors.	No new FAC reporting beyond the reporting the Partial Stipulation adopts, with the existing monthly FAC reports also provided to OPC.
37.A Earnings review or sharing	Staff: the mechanism the Commission approved for Ameren Missouri. OPC: if its LLPS revenue adjustment is not adopted, an annual refund to other classes of LLPS revenues above the amount included in rates. MECG: opposes the revenue sharing mechanism other parties propose and supports a one-way tracker.	The Earnings Review Surveillance mechanism in Exhibit D to the LLPS Stipulation. Sharing applies in a year when actual LLPS base rate revenues exceed the amount reflected in the revenue requirement. If the Company's earned ROE then exceeds its authorized ROE by more than a 20-basis-point deadband, 65 percent of the excess would be deferred for return to customers.

[1123] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 2; Ex. 219, Schaben Surrebuttal at 2; id. at 20; Ex. 217, Schaben Direct at 18; Ex. 452, Berry Rebuttal at 11.
[1124] See Ex. 111, Mastrogiannis Direct at 11; Ex. 142, Mastrogiannis Rebuttal at 9, 12; Ex. 219, Schaben Surrebuttal at 2, 20.

Issue	Positions of Other Parties	Finding the Company Requests
Section II: Non-LLPS FAC Issues		
22.B General construct[1125]	Staff: no change to the construct. OPC: no change, with the FAC continuing to track margins to a base. Google: approve the FAC methodology the Company uses.	No change to the general construct of the FAC, apart from the LLPS terms addressed under Issue 25.A.
22.C Base factor[1126]	Staff: a base factor under one of its two options. OPC: a base factor under Staff's second option or separate base factors, and the stipulated base factor is too low. Google: opposes Staff's base factor methodology.	$0.01742 per kWh, from Staff's true-up net fuel costs and net system input plus the Company's long-term capacity sales at the June 30, 2026, true-up.
22.D Sharing ratio	Staff: 95/5. OPC: 95/5.	95/5 for non-LLPS kWh, and 90/10 for incremental costs allocated to LLPS kWh until rates take effect in the Company's next general rate case.
23.C, 23.D Long-term capacity (subaccounts 555006 and 447016)[1127]	Staff: exclude both subaccounts. OPC: exclude capacity costs. Google: opposes recovering long-term capacity costs through the Schedule LLPS Interim Capacity provision.	Include long-term capacity purchases and sales in the FAC through Subaccounts 555006 and 447016, subject to the Commission's prudence review. Capacity costs separately recovered from an LLPS customer under an Interim Capacity Agreement remain excluded.
Section III: Cost of Capital		
1.A Capital structure[1128]	Staff: 52.19 percent common equity. OPC: 45 percent common equity. Value ($8,174,533).	52.19 percent common equity and 47.81 percent long-term debt.

[1125] See Google Positions at 3.
[1126] See Ex. 156, Mastrogiannis Surrebuttal/True-Up Direct at 18–19; Ex. 219, Schaben Surrebuttal at 11, 20; OPC LLPS Opposition at ¶ 10; Ex. 452, Berry Rebuttal at 8–11.
[1127] See Ex. 142, Mastrogiannis Rebuttal at 2; id. at 3; Ex. 217, Schaben Direct at 1; id. at 12.
[1128] See Ex. 165, Won Surrebuttal/True-Up Direct at 62; Ex. 207, Murray Surrebuttal/True-Up Direct at 8; Staff Reconciliation at 2, line 146.

Issue	Positions of Other Parties	Finding the Company Requests
1.B Cost of debt[1129]	Staff: 4.54 percent. OPC: 4.54 percent.	4.54 percent.
1.C Return on equity[1130]	Staff: 9.73 percent. Value ($20,757,986). OPC: 9.25 percent. Value ($17,267,839). MECG: no higher than 9.50 percent. Google: weigh the financial protections of Schedule LLPS.	10.50 percent.
1.D Rate of return[1131]	Staff: 7.25 percent. OPC: 6.66 percent.	7.651 percent.
Section IV: Income Taxes		
15.A, 15.A.i Disposition loss deduction[1132]	Staff: no reduction. OPC: reduce income tax expense. Value ($5,437,280).	Income tax expense as the Partial Stipulation reflects, without OPC's disposition loss deduction.
15.C Net operating loss deferred tax asset[1133]	Staff: the book balance, including the unamortized net operating loss carryforward. OPC: none. Value ($2,941,318).	Include in rate base the unamortized net operating loss deferred tax balance reflected in the Company's accumulated deferred income taxes at the June 30, 2026, true-up.

[1129] See Ex. 165, Won Surrebuttal/True-Up Direct at 63; Ex. 207, Murray Surrebuttal/True-Up Direct at 8.
[1130] See Ex. 165, Won Surrebuttal/True-Up Direct at 64; Ex. 207, Murray Surrebuttal/True-Up Direct at 8; Ex. 450, Berry Revenue Requirement Direct at 9; Staff Reconciliation at 1, line 7; id. at 2, line 145; MECG Positions at 2.
[1131] See Ex. 165, Won Surrebuttal/True-Up Direct at 66; Ex. 207, Murray Surrebuttal/True-Up Direct, Sch. DM-S-2; id. at 8.
[1132] See Staff Reconciliation at 2, line 149.
[1133] See Staff Reconciliation at 2, line 151.

Issue	Positions of Other Parties	Finding the Company Requests
Section V: Fuel and Purchased Power[1134]		
5.A–D Fuel and purchased power[1135]	Staff: variable fuel and purchased power cost as stated in its true-up filing, with fuel prices, market prices, and transmission congestion rights margin based on periods ending June 30, 2026.	Staff's variable fuel and purchased power cost, as adopted in the LLPS Stipulation, with the Missouri jurisdictional amount as reflected in Staff's reconciliation, and Staff's fuel prices, normalized market prices, and transmission congestion rights margin.
Section VI: Renew Missouri Programs and MEEIA Margin Rates		
42.A Net marginal rates	Staff: does not oppose the Company's method, with the rates recalculated on the final rates in this case.	The Schedule GAJ-12 method, applied to the rates and billing determinants approved in this case, with updated MEEIA net margin rates filed with the compliance tariff sheets.
Section VII: PISA		
18.B Deferral in rate base	OPC: to the extent the $21.8 million lateral rebuild project, the $20.8 million substation projects, and the $73.1 million transmission projects are in the deferral, remove them. Staff: signatory to the Partial Stipulation, which adjusts the deferral for any plant disallowance that OPC's witnesses identified and the Commission orders.	The balance in Exhibit B to the Partial Stipulation, without the reductions OPC proposes.

[1134] The LLPS Stipulation lists Issue 5 among the issues it resolves. The findings the Company requests in this Section adopt the positions of Staff's witnesses, as the Company stated at hearing. See LLPS Stipulation at 4; Ex. 157, Niemeier Surrebuttal/True-Up Direct at 6; Ex. 158, Nieto Surrebuttal/True-Up Direct at 5, 6, 8; Ex. 164, Tevie Surrebuttal/True-Up Direct at 3.

[1135] See Tr. Vol. 8 at 57:24–58:11 (Staff counsel), 66:10–22 (Meitner), 75:14–23 (Niemeier).

Issue	Positions of Other Parties	Finding the Company Requests
Section VIII: Rate Base and Asset Management		
20.B Construction work in progress[1136]	Staff: none, because of the timing of the certificate case, and, if construction work in progress is included, removal of unsupported affiliate transactions. Value ($5,691,286). OPC: none.	Include $64,389,129 of construction work in progress for Mullin Creek No. 2, up to the amount the Commission determines in Case No. EA-2026-0154, with that case decided before or with this one. Alternatively, include it contingent on the Commission's findings in that case.
20.C Retired plant[1137]	Staff: remove retired plant from the return calculation. Value ($4,416,800).	No removal, and a return on all rate base.
20.E Return on construction work in progress[1138]	Staff: the overall rate of return. OPC: 5.08 percent. Value ($2,420,121).	The overall rate of return, with no separate capital structure for construction work in progress.
20.F, 20.H Transmission investment[1139]	OPC: remove $73.1 million of transmission projects under Issue 20.F and, separately, the $14.7 million at issue under Issue 20.H. Values ($3,438,914) for rate base and ($1,018,501) for depreciation, listed for the transmission projects.	Include the transmission investment, with no reduction under Issue 20.H.
19.A Distribution investment[1140]	OPC: remove $21.8 million for the lateral rebuild project and $20.8 million for substation projects. Values ($1,079,932) for rate base and ($319,076) for depreciation for the lateral rebuild project. Values ($1,031,200) for rate base and ($304,678) for depreciation for the substation projects.	Include the distribution investment in the Company's true-up rate base.

[1136] See Staff Reconciliation at 1, line 35.
[1137] See Staff Reconciliation at 1, line 40.
[1138] See Staff Reconciliation at 2, line 148.
[1139] See Staff Reconciliation at 2, lines 158–160.
[1140] See Staff Reconciliation at 2, lines 152–157.

Issue	Positions of Other Parties	Finding the Company Requests
19.B Asset prioritization[1141]	Staff: no, although it recommends no disallowance. OPC: no.	Yes.
Section IX: Income-Eligible Programs and Energy Burden Analysis		
16.E, 16.E.i–ii Customer charge waiver[1142]	OPC: create a program with a $6 million annual budget and waive late fees for qualifying customers. Staff: continued development in the Affordability Docket. On late fees, no opposition, although Staff needs a program's full details to take a position. If a program is approved, recovery of the waived revenues from all classes on the basis of the otherwise-applicable class revenue requirements or, alternatively, as a program expense. MECG: if a program is approved, recovery from the Residential class or, if from all classes, on a per-customer basis. Google: development in the Affordability Workshop.	No program in this case, with development continuing in the Affordability Workshop. If a program is approved, no late-fee waiver in this case, and no decision on recovery of the waived revenues is needed.
Section X: Rates and Revenue Responsibility[1143]		
29.A.ii Reactive demand	Staff: objects. OPC: opposes.	Remove reactive demand charges from the Medium and Large General Service classes.

[1141] See Staff Positions at 15.
[1142] See Google Positions at 3.
[1143] Most findings the Company requests in this Section rest on the terms of the Rate Design Settlement. The exceptions are the findings on Issues 29.A.iv–v, 32.D (further discussed herein), and 33, the alternative findings on Issues 32.A.i–ii, and the affordability part of the finding on Issue 32.B. MECG signed that agreement, and Google does not oppose it. Staff objects to it in part, and OPC objects to the terms it lists. See Rate Design Settlement at 1–2, 5 & ¶ 11; MECG Response at ¶ 3; Staff Rate Design Objection at ¶¶ 3–4; OPC Rate Design Opposition at ¶¶ 1–4.

Issue	Positions of Other Parties	Finding the Company Requests
29.A.iii Charges and rate structure	Staff: objects to the demand and energy factors and to deferring the voltage review. Staff does not object to the demand thresholds or 15-minute demand, or to eliminating all-electric rates once restructured rates take effect. OPC: opposes the demand thresholds, 15-minute demand, the voltage review term, eliminating all-electric rates, and intra-class shifts without customer education.	Charges and rate structures as the Rate Design Settlement provides.
29.A.iv–vi, 32.C Study, education, and implementation	Staff: delay for customer education and a determinants study, and objects to immediate implementation by bill cycle. OPC: opposes intra-class shifts without customer education and reallocation without a rate mitigation study.	Restructured rates and the rate increase take effect together, by bill cycle, without the delay Staff proposes. No separate billing determinants and customer impact study as a condition of implementation, and targeted customer education by the Company after the Commission's order.
29.B Optional time-based rates	Staff: objects. OPC: opposes.	Implement the Company's optional time-of-use rate for non-residential customers, as modified by the Rate Design Settlement.
30.A, 30.A.i Other rates and Time Related Pricing	Staff: does not object to the freeze, and objects to the 1.1 factor and to the settlement's revenue allocation. OPC: opposes the Time Related Pricing terms. MECG: supports the freeze.	Freeze Time Related Pricing for current non-residential customers, with its components increased 1.1 times the system average increase. Increase the electric vehicle and lighting rates by 112.50 percent of the system average increase, with the Rate Design Settlement's LED weighting, and do not increase rates not set in a general rate case.

Issue	Positions of Other Parties	Finding the Company Requests
30.A.ii Schedule LLPS rates	Staff: objects to an LLPS increase smaller than the residential and small business increase. Google: no increase and does not oppose the Rate Design Settlement.	Increase Schedule LLPS rates as a subclass of the Large Power Service class under the Rate Design Settlement's allocation.
32.A, 32.A.i–ii, 32.B Revenue apportionment	Staff: an equal percentage increase to all classes. OPC: opposes the allocation and any reallocation without a rate mitigation study. OPC would base apportionment on a class cost of service study using the probability of dispatch method and the Basic Customer method. On affordability, OPC supports its customer charge waiver program and would have data centers bear the capital and fuel costs they cause. Google: reallocate LLPS net revenues to non-Schedule LLPS customers consistent with Paragraph 14.ii of the Global Stipulation.	Allocate revenue by the class percentages in the Rate Design Settlement, with affordability addressed through that allocation and the income-eligible programs. No decision on distribution classification or production allocation is needed. If one is made, the minimum system method and an average and excess allocation.
32.D Construction work in progress allocation	OPC: assign entirely to the LLPS class. Google: allocate by the average and excess four coincident peak method. Staff: equal percentage increases for all classes.	No direct assignment to LLPS customers, with the associated revenue requirement apportioned through the class percentages in the Rate Design Settlement. The Company will propose a Schedule LLPS cost allocation in the first rate case with a 75 MW or greater LLPS customer in the test year, as the Global Stipulation provides.
33.A, 33.A.i, 33.B Critical peak rate	Staff: implement, not applicable to service before November 1, 2027, with a separate line on the fuel adjustment rate tariff. MECG: no.	No critical peak rate, no accommodation beyond the extraordinary-event language in the Partial Stipulation, and no separate line on the fuel adjustment rate tariff.

Issue	Positions of Other Parties	Finding the Company Requests
Section XI: Trackers		
36.A, 36.B Expense and tracker[1144]	Staff: the test year level, and no tracker. OPC: Staff's test year level, and no tracker.	Staff's corrected test-year level of $4,491,745 on a total-company basis, with the CIP and cyber security tracker on the terms Section XI describes.
Section XII: Depreciation		
17.A (reserved portion) Retirement dates for Iatan Unit 1, La Cygne Unit 2, and La Cygne Common[1145]	MECG: later probable retirement dates for Iatan Unit 1 and La Cygne Unit 2, with Mr. Andrews also moving La Cygne Common. Value ($25,370,000), listed for MECG's revised depreciation rates before MECG's October 7 response, which addresses only the two units. Staff: signatory to the Partial Stipulation and opposes Mr. Andrews's retirement dates.	The Exhibit C rates, as corrected, without Mr. Andrews's retirement-date adjustments, including for La Cygne Common.

[1144] See Ex. 140, Lyons Rebuttal at 10; Ex. 168, Majors Surrebuttal/True-Up Direct at 15; Ex. 140, Lyons Rebuttal at 11.
[1145] See Ex. 300, Andrews Direct at 28; Staff Reconciliation at 2, line 164.

Major energy rate case decisions in the US January-June 2026

Quarterly update on decided rate cases

Lisa Fontanella, Research Director

Contributors: Jim Davis, Heike Doerr, Russell Ernst, Monica Hlinka, Jason Lehmann, Dan Lowrey and Cameron Mays

Editor: Majda Shabbir

For detailed data

Access the RRA's electric and gas rate case decisions as of June 30, 2026 and related data.

While electric utility authorized returns in the first half of 2026 remained identical to their 2025 averages, gas utility authorized returns experienced a decline.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

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Executive Summary

Introduction

Based on Regulatory Research Associates' review of recent rate case outcomes, the average authorized return on equity (ROE) for electric utilities held steady at 9.84% in the first half of 2026, matching the 2025 full-year average, whereas the average authorized ROE for gas utilities edged down to 9.83% from 9.87%.

First-half results point to modest downward pressure on authorized returns, as commissions continue to balance significant capital investment needs with heightened customer affordability concerns.

State public utility commissions issued approximately 58 rate case decisions in the first half of 2026, including 38 electric and 20 gas cases, with 38 equity return determinations. These decisions included 38 general rate cases and 20 limited-issue cases.

In calendar 2025, commissions issued approximately 203 rate case decisions, including 105 for electric and 98 for gas utilities, with 154 equity return determinations. Those decisions included 119 general rate cases and 84 limited-issue cases.

Capital investment recovery continues to be the primary driver of rate case filings. Utilities are advancing significant spending to modernize transmission and distribution systems, expand natural gas and renewable generation, and deploy technologies supporting electric vehicles, battery storage and advanced metering infrastructure. Additional factors include rising operating costs, evolving cost-of-capital assumptions, storm-related cost recovery, and the financial impacts of early generation retirements associated with energy transition. Many filings also include proposals for alternative ratemaking mechanisms, aimed at addressing cost volatility and mitigating regulatory lag.

Average authorized ROE (%)

	2025	H1 2026	LTM ended 6/30/2026
Electric averages			
All cases	9.84	9.84	9.82
General rate cases	9.77	9.79	9.77
Vertically integrated cases	9.87	9.85	9.86
Distribution cases	9.56	9.61	9.61
General rate cases — fully litigated	9.74	9.71	9.74
General rate cases — settled	9.78	9.81	9.79
Limited-issue rider cases	9.93	10.05	9.95
All cases — fully litigated	9.86	9.88	9.86
All cases — settled	9.78	9.81	9.79
Gas averages			
All cases	9.87	9.83	9.85
General rate cases	9.70	9.64	9.67
General rate cases — fully litigated	9.75	9.61	9.68
General rate cases — settled	9.68	9.65	9.67
Limited-issue rider cases	10.21	10.25	10.27
All cases — fully litigated	10.02	10.12	10.03
All cases — settled	9.68	9.65	9.67
Composite electric and gas averages			
Electric and gas — all cases	9.85	9.84	9.84
Electric and gas — general rate cases	9.74	9.74	9.73
US Treasury			
30-year bond yield	4.78	4.89	4.84

Data compiled Aug. 14, 2026.

ROE = return on equity; LTM = last-12-months; N/A = not applicable.

Sources: Regulatory Research Associates, a group within S&P Global Energy; US Treasury Department.

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About this report

This quarterly report presents a comprehensive analysis of electric and gas rate case decisions issued in the US during the first half of 2026, along with select aggregated historical data. The report uses data included in RRA's rate case database, available on S&P Capital IQ Pro. RRA tracks all "major" rate cases for investor-owned utilities nationwide, defining "major" as cases where the utility is seeking a rate change of at least $5 million, or where the commission approves a rate change of at least $3 million. Beyond base rate cases, the database includes details on certain limited-issue rider proceedings, particularly those involving significant rate base additions outside of a general rate case. To provide continuity of coverage for a given utility, certain rate cases included in the database may not conform to the rate change coverage criteria.

Historical data in this report may differ from previous reports due to variations in presentation, such as the treatment of withdrawn or dismissed cases and the inclusion of cases not previously included in RRA's coverage. In addition, in early 2026, RRA enhanced its dataset of rate case decisions to include decisions rendered as part of formula rate plans that were previously not fully reflected in the averages, as well as decisions authorized each quarter in Pennsylvania for the utilities' distribution system improvement charges as part of the Pennsylvania Public Utility Commission's quarterly earnings review process. The enhanced dataset is still in the process of being backfilled for the years prior to 2020. Accordingly, this report presents the legacy RRA-based and the enhanced datasets, which reflects improved granularity, particularly regarding authorized returns on equity. However, it is currently only backfilled for the period from 2020 through the first half of 2026. Because the process of backfilling historical observations is ongoing, the enhanced dataset is not yet complete for all years.

The Take

The average authorized ROE for electric utilities was unchanged in the first half of 2026 compared with the full-year 2025 average, while the average authorized ROE for gas utilities declined.

Authorized ROEs have generally not kept pace with the higher interest rate environment. Regulators have shown increasing caution in raising allowed returns amid intensifying customer affordability concerns. Rising customer bills, driven by persistent inflationary pressures, elevated wholesale power costs and accelerating capital investment in areas, such as grid modernization, system resilience and policy-driven infrastructure development, have heightened scrutiny of rate increases and contributed to a more measured approach to setting authorized returns. At the same time, expanding capital programs and a high volume of rate case filings have increased political and regulatory pressure to moderate customer bill impacts.

Looking ahead, RRA expects elevated rate case activity to persist, supported by continued capital investment requirements and interest rates, as well as inflation that remain above pre-pandemic levels. Additional demand growth, particularly from data center development, is likely to further increase system investment needs. Affordability considerations are expected to remain central to regulatory decision-making, potentially limiting upward movement in authorized returns despite ongoing utility investment requirements.

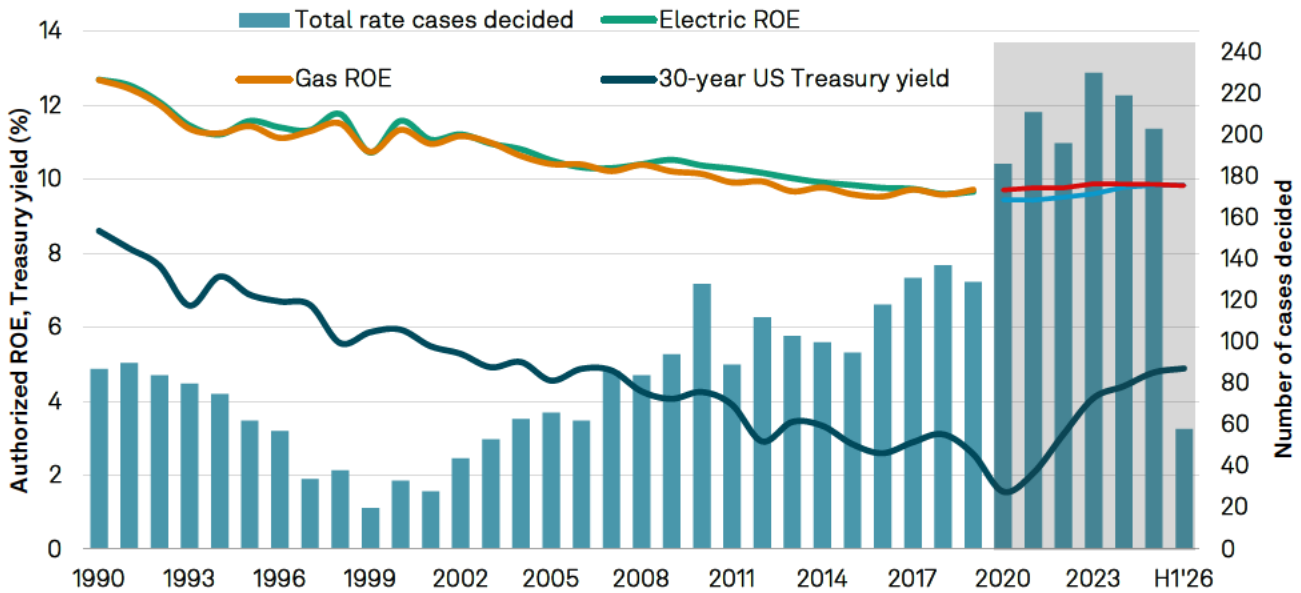
Overview of electric and gas authorizations — enhanced dataset

In the first half of 2026, the average authorized ROE for all electric utilities was unchanged compared with the full-year 2025 average, while the average authorized ROE for gas utilities declined compared to the full-year average for 2025.

According to calculations by RRA, the overall average authorized ROE for electric utilities was 9.84% in rate cases decided in the first half of 2026, equal to the average for full year 2025. There were 25 electric ROE authorizations in the first half of 2026 versus 86 in full year 2025.

The average ROE authorized for gas utilities was 9.83% in rate cases decided in the first half of 2026, slightly below the 9.87% in rate cases decided in full year 2025. There were 13 gas ROE authorizations in the first half of 2026 versus 68 in full year 2025.

All cases — average electric, gas authorized ROEs; total number of rate cases decided



Data compiled Aug. 14, 2026.

ROE = return on equity.

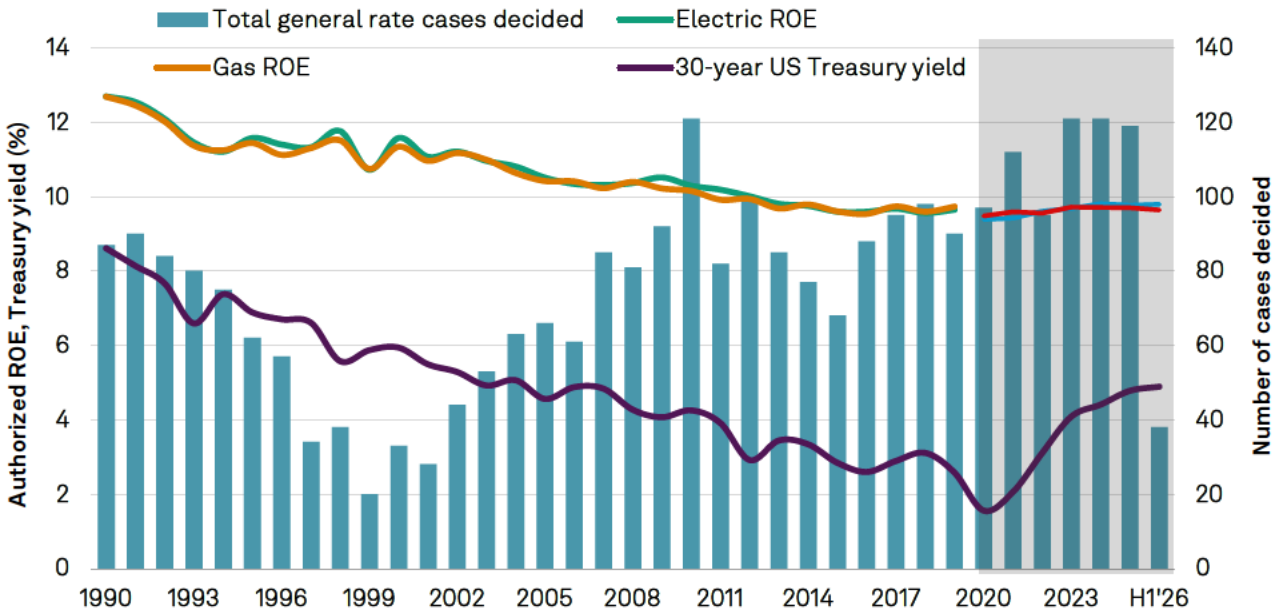
The rate case data for 1990-2019 will be backfilled and is subject to revision. The rate case data for 2020 and beyond reflect the enhanced dataset.

Sources: Regulatory Research Associates, a group within S&P Global Energy; US Treasury Department.

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There were five limited-issue rider cases with an authorized electric ROE in the first half of 2026 versus 36 in full year 2025. Excluding the rider cases, the average authorized ROE for electric cases was 9.79% in the first half of 2026 versus 9.77% in full year 2025. There were four limited-issue rider cases with an authorized gas ROE in the first half of 2026 versus 22 in full year 2025. Excluding rider cases, the average authorized ROE for gas cases was 9.64% in the first half of 2026 versus 9.70% in full year 2025.

General rate cases — average electric, gas authorized ROEs; total decided rate cases



Data compiled Aug. 14, 2026.
ROE = return on equity.
The rate case data for 1990-2019 will be backfilled and is subject to revision. The rate case data for 2020 and beyond reflect the enhanced dataset.
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Many of the limited-issue rider cases rely on previously approved ROEs that are excluded from the averages. In addition, in the past, some of the limited-issue rider cases included incentives causing the ROEs authorized in these cases to be significantly higher than those approved in general rate cases, raising the overall average. However, these premiums have largely expired. A significant number of these limited-issue rider cases now include the quarterly market-based proxy returns established by the Pennsylvania PUC.

In the first half of 2026, the median ROE authorized in all electric utility rate cases was 9.78% versus 9.80% in full year 2025. For all gas utility rate cases, the median was 9.79% in the first half of 2026 and 9.80% in full year 2025. For the electric general rate cases, the median ROE authorized was 9.75% in the first half of 2026 versus 9.70% in full year 2025. For gas general rate cases, the median ROE authorized was 9.75% in the first half of 2026 and 9.75% in full year 2025.

For the limited-issue rider cases, the electric median ROE was 10.05% in the first half of 2026 versus 10.00% in full year 2025, while the gas median ROE was 10.25% in the first half of 2026 versus 10.20% in full year 2025.

Looking at the last-12-months ended June 30, 2026, the average ROE authorized in all electric utility rate cases was 9.82% and the median was 9.78%, while for gas utilities, the average was 9.85% and the median was 9.80%.

Looking at the last-12-months ended June 30, 2026, the average ROE authorized in all electric general rate cases was 9.77% and the median was 9.73%, while for gas general rate cases, the average was 9.67% and the median was 9.65%.

Authorized returns have generally followed the overall direction of interest rates but with a lag. However, the magnitude of the year-over-year change in authorized ROEs is generally much smaller than interest rate changes.

Interest rates — as measured by the 30-year US Treasury bond yield — declined steadily from 1990 to 2020, exerting downward pressure on authorized ROEs. During this period, Treasury yields dropped over 700 basis points, to 1.56% from 8.61%. Meanwhile, the average authorized ROEs for electric and gas utilities combined decreased less than 325 basis points, to 9.56% from 12.69%. Notably, average authorized ROEs for all cases did not fall below 10% until 2011 for gas utilities and 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020 for the electric group.

The overall decline in authorized ROEs coincided with an increase in rate case activity.

Between 1990 and 2020, interest rates and authorized ROEs declined at different rates, leading to a widening spread between authorized ROEs and the average yield on 30-year US Treasurys. This spread increased to about 800 basis points in 2020 from just over 400 basis points in 1990.

The widening spread is primarily due to regulators' implicit understanding that the interest rate drop driven by the US Federal Reserve intervention was atypical. Consequently, regulators did not fully reflect the interest rate drop in newly authorized ROEs. In some instances, regulators recognized that industry changes and economic instability posed increased risks for investors, justifying a higher premium over interest rates.

The spread has been narrowing since 2020 — when interest rates began to rise, but authorized ROEs did not keep pace — reaching about 500 basis points in 2025. Given the various factors increasing customer bills and increased affordability scrutiny, the spread may continue to narrow, as regulators may become more reluctant to raise authorized returns.

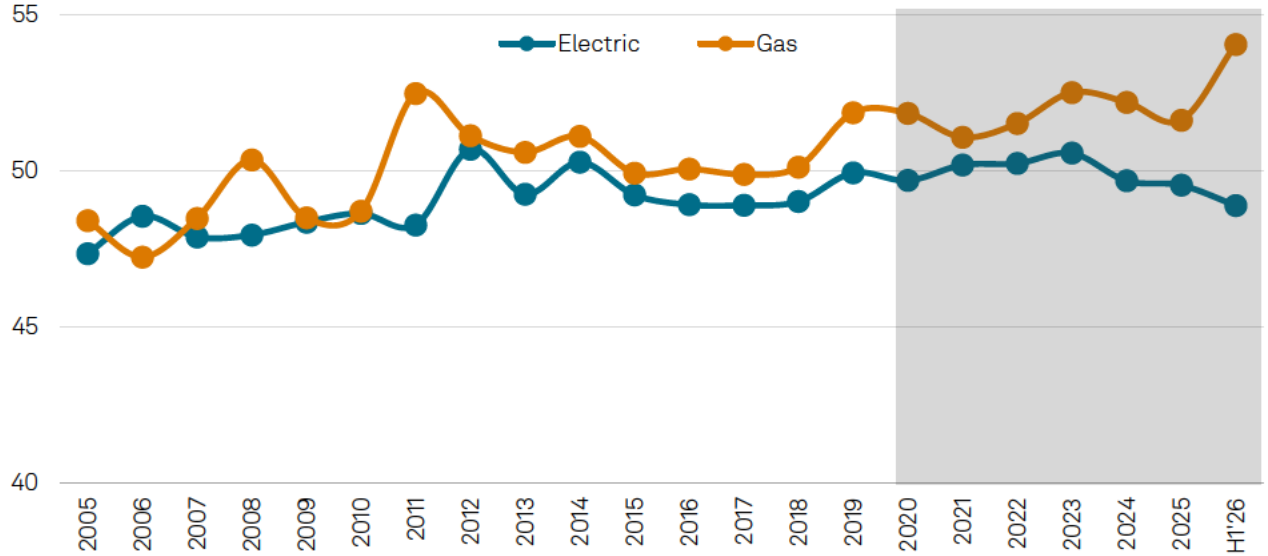
Capital structure trends

The negative cash flow impact from the 2017 federal tax legislation raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios. Consequently, the authorized equity ratios adopted by utility commissions in 2019 averaged 49.94% for electric utilities and 51.86% for gas utilities, modestly higher than the averages for 2018 and 2017, and almost 300 basis points above the levels observed in 2005.

Since then, authorized ROEs for electric utilities have fluctuated at about 50%, with the average for the first half of 2026 coming in at 48.89% versus 49.54% in full year 2025. For gas utilities, the average has been slightly higher, reaching 54.06% in the first half of 2026 and 51.63% in full year 2025.

Exhibit A
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Average authorized equity ratio (%) — all cases



Data compiled Aug. 14, 2026.
Data prior to 2020 is subject to revision; data for 2020 and beyond reflect the enhanced dataset.
Sources: Regulatory Research Associates, a group within S&P Global Energy; US Treasury Department.
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A more granular look at ROE trends

So far, the discussion has focused on broad trends in authorized ROEs. The following sections provide a more detailed analysis.

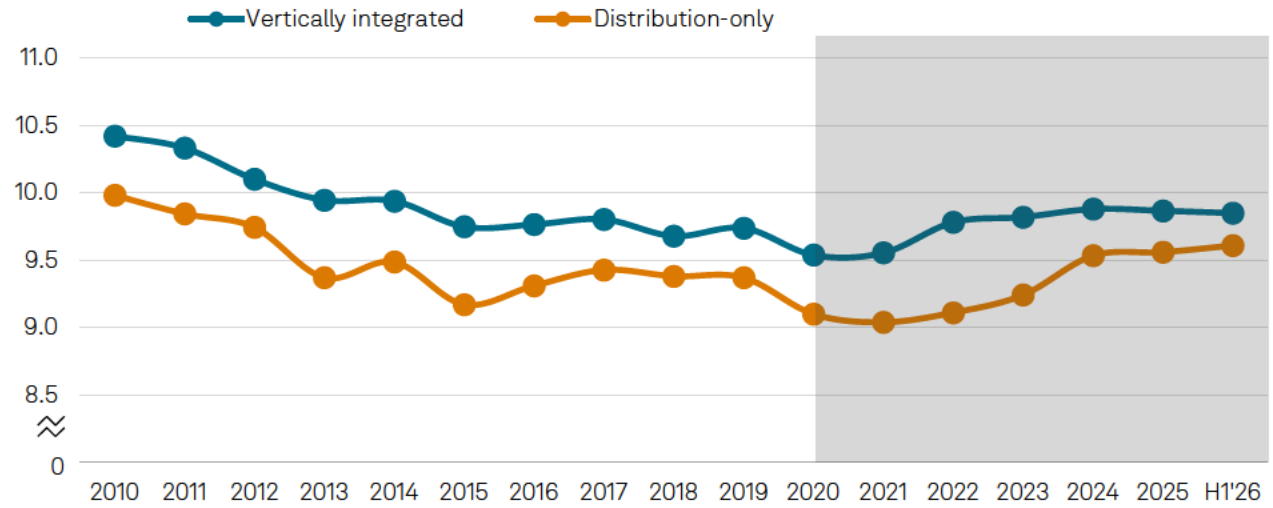
RRA has noted significant differences in average ROEs based on the types of proceedings or decisions in which these ROEs were established.

Due to the restructuring of the electric industry, several states have unbundled electric rates and introduced retail competition for electric generation. In these states, commissions have jurisdiction only over return parameters and revenue requirements for distribution operations.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation assets have historically been about 30-67 basis points higher than in distribution-only cases. This difference is attributable to the increased risk associated with the construction, ownership and operation of generation assets, as well as the procurement of fuel supplies.

The industry average ROE for vertically integrated electric utilities was 9.85% in cases decided in the first half of 2026, versus the 9.87% average in full year 2025. For electric distribution-only cases, the average industry ROE was 9.61% in the first half of 2026 versus 9.56% in full year 2025.

Average authorized electric ROEs (%)

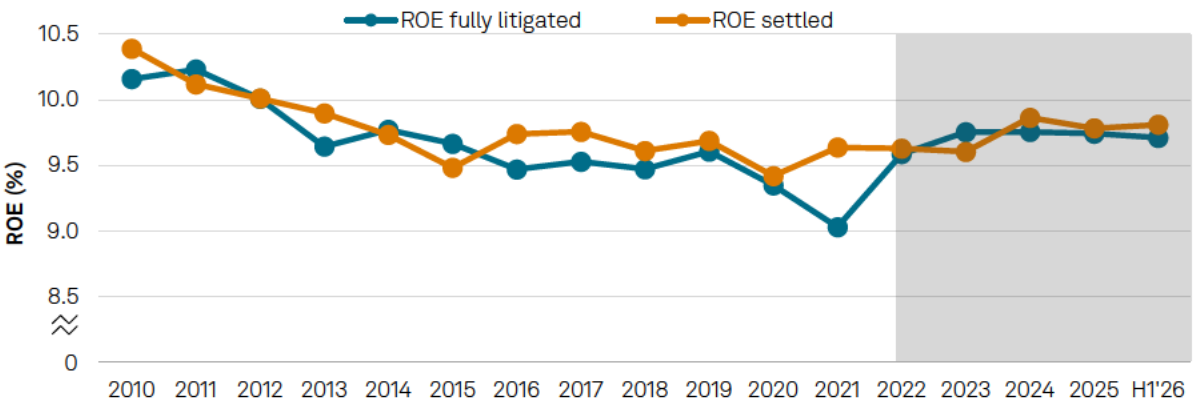


Data compiled Aug. 14, 2026.
ROE = return on equity.
Data prior to 2020 is subject to revision; data for 2020 and beyond reflect the enhanced dataset.
Source: Regulatory Research Associates, a group within S&P Global Energy.
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In recent years, settlements have frequently been used to resolve general rate cases, with some taking the form of "black box" settlements. These do not specify the ROE or other typical rate case parameters underlying the stipulated rate change. However, some states require settlements to specify these values, even if they do not provide all the specific adjustments from which these values were derived.

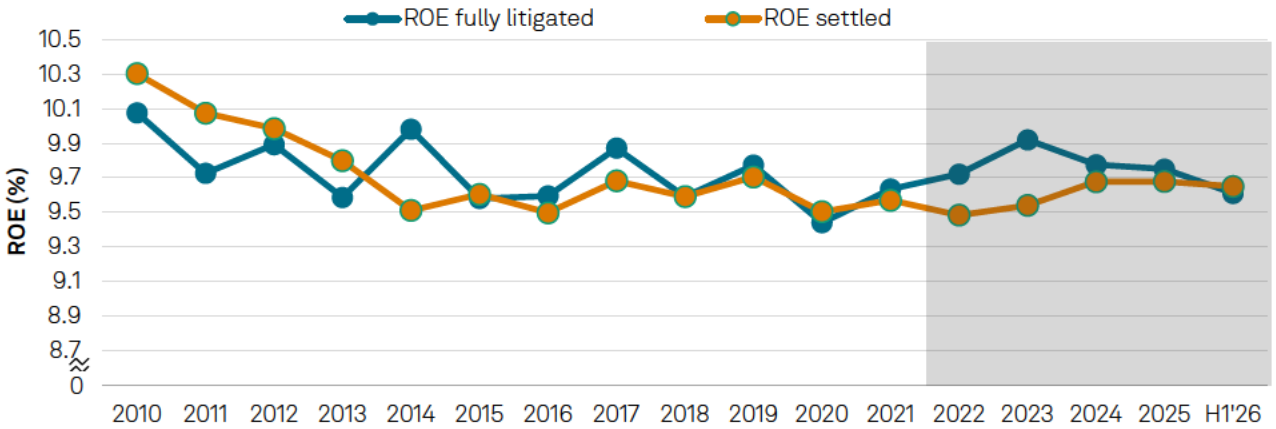
For both electric and gas cases, RRA has observed no consistent pattern in the relationship between average authorized ROEs for settled and fully litigated cases. In some years, the average authorized ROE was higher for fully litigated ones, while in others, the opposite was true.

Electric general rate cases: Average authorized ROEs — settled vs. fully litigated cases



Data compiled Aug. 14, 2026.
ROE = return on equity.
Data prior to 2020 is subject to revision; data for 2020 and beyond reflect the enhanced dataset.
Source: Regulatory Research Associates, a group within S&P Global Energy.
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Gas general rate cases: Average authorized ROEs — settled vs. fully litigated cases



Data compiled Aug. 14, 2026.
ROE = return on equity.
Data prior to 2020 is subject to revision; data for 2020 and beyond reflect the enhanced dataset.
Source: Regulatory Research Associates, a group within S&P Global Energy.
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The following discussion focuses on these corresponding tables available here.

Tables 1a, 1b, 1c and 1d show the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2021, as well as those authorized in only general rate cases followed by the number of observations in each period.

Tables 2a, 2b, 2c and 2d indicate the composite electric and gas industry data for all major cases, as well as for general rate cases only summarized annually since 2005 and quarterly since 2022.

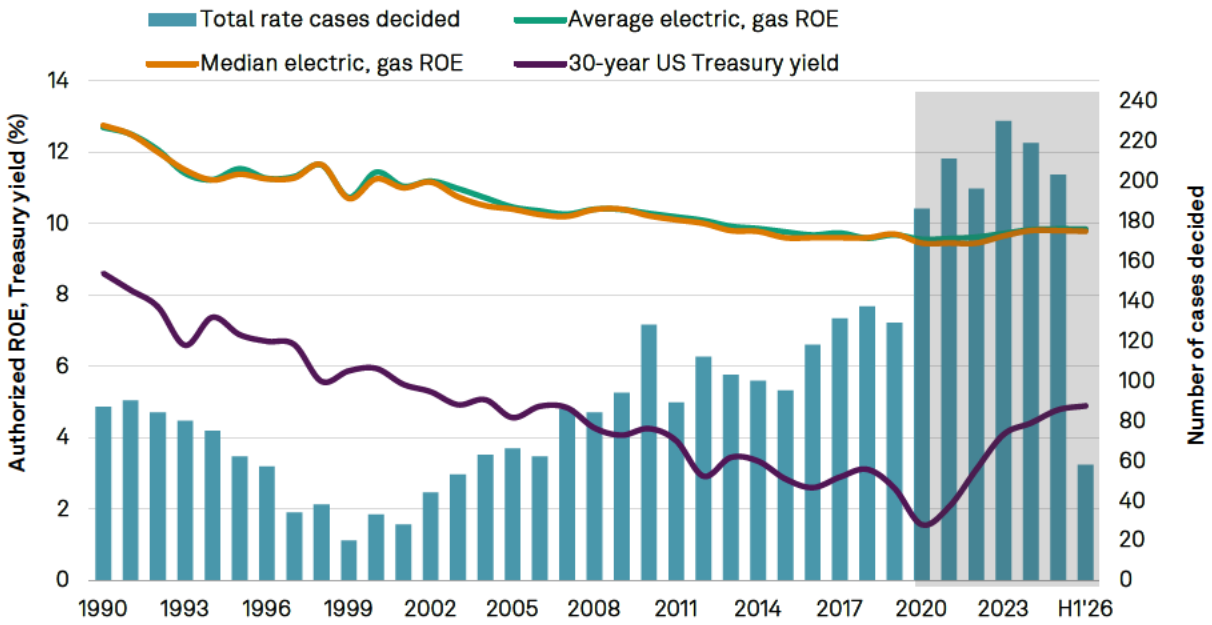
Tables 3 and 4 provide comparisons of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus distribution-only cases for electric and gas utilities since 2010.

Tables 5a and 5b list the individual electric and gas cases decided in 2026. The decision date is shown first, followed by the company name, company ticker, abbreviation for the state issuing the decision, authorized rate of return, ROE, and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered when the decisions were rendered. This study does not reflect fuel adjustment clause rate changes.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified periods; they are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graphs below track the average and median equity return authorized for all electric and gas rate cases since 1990, as well as for general rate cases only. As the table indicates, the average authorized ROEs have generally trended downward since 1990, reflecting the significant decline in interest rates and capital costs over this time frame. However, with the higher interest rate environment in the past couple of years, the average is beginning to trend moderately upward.

All cases — composite electric, gas average authorized ROEs; total number of rate cases



Data compiled Aug. 14, 2026.

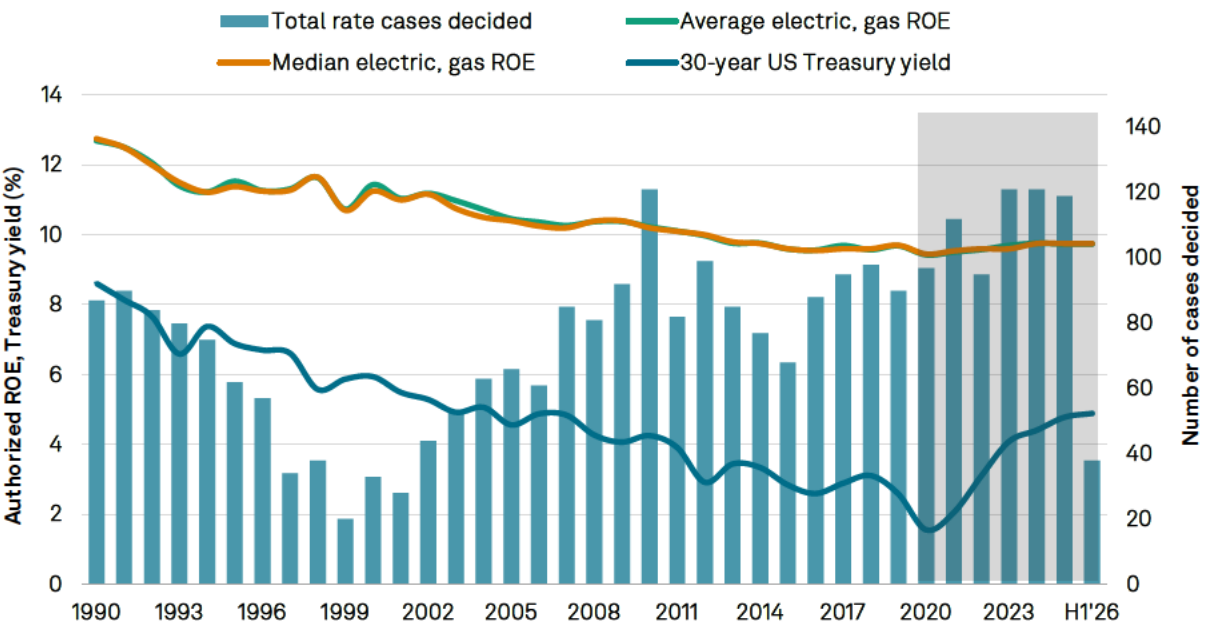
ROE = return on equity.

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General rate cases — composite electric, gas average authorized ROEs; total number of rate cases



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Further Reading

Major energy utility cases in progress in the US, July 2026

State Regulatory Evaluations: Energy, June 2026 Release

The rate case process: a conduit to enlightment

Rate base: It's more complicated than it sounds

An Overview of FERC Regulation

Adjustment Clauses – a state-by-state overview

FERC Regulatory Review

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