Exhibit No.:	
Issue:	Policy; Overview; Introduction of Witnesses; Proposed Rate Increase; Regional Rate Competitiveness; Large Load Customers; Proposed Mechanisms; Fuel Adjustment Clause Recommendations; Crossroads
Witness:	Kevin D. Gunn
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Evergy Missouri West
Case No.:	ER-2027-0077
Date Testimony Prepared:	November 3, 2026

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2027-0077

DIRECT TESTIMONY

OF

KEVIN D. GUNN

ON BEHALF OF

EVERGY MISSOURI WEST

Kansas City, Missouri
November 2026

TABLE OF CONTENTS

I. INTRODUCTION 1

II. OVERVIEW OF EVERGY MISSOURI WEST'S OPERATIONS 5

III. PROPOSED RATE INCREASE 7

IV. REGIONAL RATE COMPETITIVENESS 13

V. SECTION 393.130.7 AND LARGE LOAD CUSTOMERS 16

VI. PROPOSED MECHANISMS AND OTHER REQUESTS OF THE COMMISSION 21

A) PLANT IN SERVICE ACCOUNTING 21

B) CONSTRUCTION WORK IN PROGRESS 22

C) EARNINGS REVIEW SHARING MECHANISM 24

D) CYBER TRACKER 25

E) INJURIES AND DAMAGES RESERVE 26

F) STORM RESERVE 27

VII. FUEL ADJUSTMENT CLAUSE RECOMMENDATIONS 27

A) FAC REQUEST 1: ELIMINATION OF THE 95/5% RISK SHARING 28

B) .....FAC REQUEST 2: INCLUSION OF LONG-TERM CAPACITY COSTS IN EMW'S FAC 34

C) FAC RECOMMENDATION 3: A TOTAL RECOVERY OF UTILITY ENERGY COSTS FAC ("TRUE FAC") 36

VIII. CROSSROADS ENERGY CENTER 39

IX. CONCLUSION 40

DIRECT TESTIMONY

OF

KEVIN GUNN

CASE NO. ER-2027-0077

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Kevin D. Gunn. My business address is 1200 Main Street, Kansas City, Missouri 64105.

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

A: I am employed by Evergy Metro, Inc. and serve as Vice President – Regulatory and Government Affairs for Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("EMM"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West," "EMW," or the "Company"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("EKM"), and Evergy Kansas Central, Inc. and Evergy Kansas South, Inc., collectively d/b/a Evergy Kansas Central ("EKC"). These are the operating utilities of Evergy, Inc. ("Evergy").

Q: On whose behalf are you testifying?

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

Q: What are your responsibilities as the Vice President – Regulatory and Government Affairs?

A: My responsibilities include developing and implementing Evergy's regulatory policy at the state and federal level, including managing regional transmission organization ("RTO") policy. Currently, my state duties are limited to Government Affairs and Missouri regulatory policy.

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

A: I received a Bachelor of Arts from American University in 1992 and a Juris Doctor from St. Louis University School of Law in 1996. I was a Commissioner on the Missouri Public Service Commission from 2008 to 2013 and served as Chair from 2011 to 2013. Prior to being on the Commission, I served as a lawyer in private practice and as a Congressional Chief of Staff. Subsequent to serving on the Commission, I was a regulatory affairs consultant and Executive Director of Regulatory and Political Affairs, Central Region for NextEra Energy Resources.

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

A: Yes. I have provided testimony before the PSC, most recently in EMM's rate proceeding, Case No. ER-2026-0143, EMM and EMW's large load tariff filing, Case No. EO-2025-0154, EMW's rate case, Case No. ER-2024-0189, EMM and EMW's Knock & Collect Case No. EE-2025-0084, and recent Certificate of Convenience & Necessity Case No. EA-2024-0292, EA-2025-0075, EA-2026-0154, and Case No. EA-2026-0343.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to provide the Commission with a policy-level overview of Evergy Missouri West's requests in this rate proceeding and to explain how those requests work together to support four related objectives: maintaining safe, adequate, and reliable service; preserving customer affordability and regional rate competitiveness; preparing the Company's system for continued customer and large-load growth; and maintaining the financial integrity necessary to fund prudent investments on reasonable terms.

I describe EMW's operations and the principal drivers of the Company's requested revenue increase, including the investments and costs necessary to serve customers and the revenues expected from new customers. I also introduce the Company witnesses who support the filing and identify the subjects each witness addresses. In addition, I discuss EMW's regional rate competitiveness, the implementation of Section 393.130.7 through Schedule Large Load Power Service, and the protections and benefits associated with anticipated large-load growth.

Finally, I provide the policy basis for the principal mechanisms and other relief requested in this case, including plant-in-service accounting, construction work in progress, the temporary Earnings Review Sharing mechanism, the cybersecurity tracker, the storm and injuries-and-damages reserves, and the Company's proposed changes to its fuel adjustment clause. I also identify Company witnesses Mr. Ives and Mr. VandeVelde as the witnesses that provide an overview and support of the Company's proposed prospective treatment of the Crossroads Energy Center. The Company's other witnesses provide the supporting calculations, accounting treatment, operational evidence, tariff provisions, and other technical details associated with these requests.

Q: Please introduce the Company's other witnesses who support EMW's rate request.

A: Table 1, below, introduces the Company's other witnesses and the topics they address.

Table 1: EMW Witnesses

Witness Name:	Topics:
Albert R. Bass, Jr.	Weather Normalization; 365-day Year Adjustment; Rate Switchers and Customer Growth; Energy Efficiency Annualization
Patrick Aron Branson	Accounting Adjustments
Ann E. Bulkley	Cost of Capital; Capital Structure; Return on Equity
Jeremy Fischer	Accounting Adjustments

Witness Name:	Topics:
Zachary Gladhill	Large Load Customers; Economic Development
Kevin D. Gunn	Policy; Overview; Introduction of Witnesses; Proposed Rate Increase; Regional Rate Competitiveness; Large Load Customers; Proposed Mechanisms; Fuel Adjustment Clause Recommendations; Crossroads
Melissa K. Hardesty	Accumulated Deferred Income Tax; Current and Deferred Income Tax; Excess Deferred Income Taxes; Solar Production Tax Credits; Property Tax; Foxtrot and Sunflower Sky Tax Strategy; Kansas City Earnings Tax
Jason Humphrey	Generation Additions for Solar and CWIP
Darrin R. Ives	Affordability; Crossroads Energy Center; Earnings Sharing Mechanism
Graham A. Jaynes	Rate Design; CCOS
Charles King	Cyber Tracker
Ronald A. Klote	Revenue Requirement Model and Schedules; Test Year; Misc. Accounting Adjustments including CWIP, Pensions and Other Post Employment Benefits, Security Tracker, Storm, and I&D Reserves; Earnings Sharing Mechanism
Geoffrey Ley	Capital Structure, Cost of Debt; Return on Equity Support; Mullin Creek #1 Build-to-Suit Lease Financing; Solar Tax Credits
Bradley D. Lutz	Rate Design Strategy, Tariff Modifications, Rules & Regulations, and CCOS
Katie R. McDonald	Customer Service
JP Meitner	Fuel Runs, Fuel Inventories, Fuel Prices
Ryan P. Mulvany	Distribution System; Storm Reserve
Linda J. Nunn	FAC Requirements, Misc. Accounting Adjustments
Buck Reuter	Transource; Retail v. Wholesale ROE
John J. Spanos	Depreciation Studies
Cody VandeVelde	Crossroads; EMW Steel in the Ground Discussion

Q: How is the remainder of your testimony organized?

A: The remainder of my testimony is organized in the following sections:

- Section II is an overview of EMW's operations.
- Section III is an overview of the proposed rate increase and rate design.
- Section IV discusses EMW's regional rate competitiveness.
- Section V addresses Section 393.130.7 and the Company's large load customers.
- Section VI describes the mechanisms and other requests EMW brings to the Commission in this case.
- Section VII presents the Company's recommendations regarding its fuel adjustment clause.
- Section VIII introduces the issues related to the Crossroads Energy Center.
- Section IX is the conclusion.

II. OVERVIEW OF EVERGY MISSOURI WEST'S OPERATIONS

Q: Please describe EMW's operations.

A: EMW is a regulated utility subsidiary of Evergy. EMW serves 352,500 customers, made up of 310,800 residential customers, 41,200 commercial customers and 500 industrials, municipalities and other electric utilities. EMW's electric service territory includes numerous counties in central, western and northwestern Missouri, including the cities of Lee's Summit, St. Joseph and Sedalia.

EMW's retail revenues, reflecting service provided to residences and businesses, averaged approximately 95% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales, and miscellaneous electric revenues accounted for the remainder of EMW's revenues. Like most electric utilities, EMW is

significantly impacted by seasonality, with approximately one-third of its retail revenues recorded in the third quarter.

To serve its customers, EMW owns approximately 460 megawatts ("MW") of base load generating capacity, approximately 1,300 MW of peak load capacity, and 8 MW of renewable generating capacity. In addition, EMW has over 700 MW of wind generating capacity under contract located in Missouri and Kansas. In this rate case, EMW requests that the Commission include approximately 174 MW of additional renewable generating capacity in rate base.

EMW operates and maintains approximately 14,803 circuit miles of distribution lines and approximately 1,834 circuit miles of transmission lines to serve customers across its service territory. Evergy is one of the largest companies in the region, with 4,700 employees, including nearly 2,500 union employees. These employees are active in the communities EMW serves, fulfilling the Company's mission of empowering a better future.

Q: What changes are occurring in Evergy Missouri West's customer base, including developments with large load customers?

A: Evergy is presently engaged with many prospective large load customers who are evaluating Missouri locations, including those in EMW's service territory. Evergy Missouri West's customer base is growing and becoming more diverse, particularly through prospective data centers, advanced manufacturing facilities, and other large industrial customers. The Company is working with prospective large-load customers representing more than 1.5 gigawatts of incremental demand. Those projects are at various stages of development and are being evaluated through Evergy's Path to Power process. I

will discuss this further later in my testimony, as will Company witness Zac Gladhill (Vice President of Strategy and Long-Term Planning) in his testimony.

III. PROPOSED RATE INCREASE

Q: What are Evergy Missouri West's requests in this case?

A: The Company requests authority to implement a revenue increase of $182.6 million,[1] excluding fuel. As I and other Company witnesses describe in more detail in our direct testimonies, this increase is necessary to recover the Company's investments in solar plants currently under construction and expected to be in service by the true-up date, reduce financing costs of natural gas plant construction, update regulatory amortizations, introduce anticipated revenues from new large-load customers expected to take service under the Large Load Power Service ("LLPS") customer tariff, and recover its investments and operational costs, including investments that improve reliability, modernize the grid, and enhance customer service and experience necessary to provide EMW's customers with safe and adequate service.

Q: What is the impact of this rate request on residential customers?

A: If the Commission grants this request, the increase would be $17.25 per month for the typical residential customer consuming 1,005/kWh per month, or a daily increase of $0.58, net of FAC rebase and amortization credits that currently reduce customer rates.

Q: What is the effective date of the Company's proposed tariffs filed in this case?

A: The revised tariffs in this case will bear an effective date of December 2, 2026. The Commission may suspend this filing up to an additional 10-months beyond this effective

[1] Excludes change in net fuel costs of $46.9 million and includes $44.8 million in expiring amortization costs.

date. This would place the expected effective date of new rates on or about October 2, 2027.

Q: What are the key drivers of this rate request?

A: Figure 1 below summarizes the necessary updates to EMW's revenue requirement to reflect current costs to serve its customers and to continue the Company's FAC. More than 75% of the increase is attributable to the recovery of costs associated with new generation and infrastructure investments needed to fulfill the Company's obligation to serve customers and to maintain safe and adequate electric service.

As noted by the Commission in its July 31, 2025, Report and Order in Case No. EA-2025-0075 where it approved Certificates of Convenience and Necessity ("CCN") for three natural gas generation facilities (Chisolm Trail Generation Facility ("Chisolm Trail") (formerly known as Viola Generation facility), McNew Generation Facility ("McNew"), and Mullin Creek #1 Generation Facility ("Mullin Creek #1")), "Evergy Missouri West's customer demand for energy has continued to grow since that time. The Commission agrees with Staff that Evergy Missouri West's current need for capacity is dire and that the Projects meet the Tartan need criteria."2 That same day, the Commission also approved CCNs for two solar facilities – Sunflower Sky Solar Facility ("Sunflower Sky"), an approximately 65 megawatt solar farm to be located and constructed in Wilson County, Kansas, as well as Foxtrot Solar Facility ("Foxtrot"), an approximately 100 MW solar farm to be located and constructed in Jasper County, Missouri – concluding that the facilities

[2] See Report & Order at 32, In re Evergy Missouri West CCN App. Regarding Natural Gas Facilities, No. EA-2025-0075 (July 31, 2025) ("These CCNs herein are Evergy Missouri West's first request for natural gas CCGTs and a SCGT since the retirement of its Sibley dispatchable base load coal plant in 2018. Evergy Missouri West's customer demand for energy has continued to grow since that time. The Commission agrees with Staff that Evergy Missouri West's current need for capacity is dire and that the Projects meet the Tartan need criteria.").

are "necessary or convenient for the public service."[3] Therefore, EMW is before the Commission to recover its just and reasonable costs pertaining to these facilities.

Additionally, prior rate cases have included several significant component rate reductions that have reduced rates over the past several years and are scheduled to expire before rates are effective in this rate case.

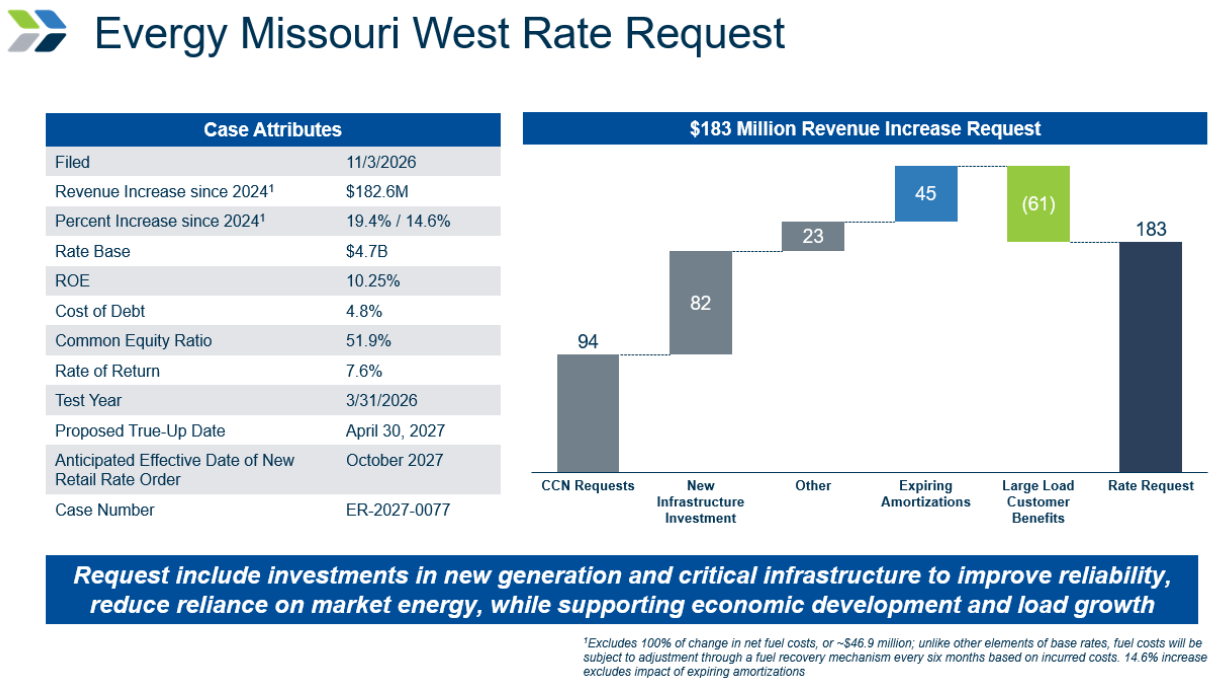
Moreover, financing costs have continued to rise. This rate request will reflect EMW's actual debt costs, proposed ROE and the capital structure needed to fund investments. These rate of return levels are supported by the testimony and analysis of Company witnesses Ann Bulkley (Principal, The Brattle Group) and Geoffrey Ley (Senior Vice President Corporate Planning and Treasurer). Updates to transmission expense and other operating expenses and revenues support the remaining revenue requirement requests.

The rate increase is significantly mitigated by incorporating customer growth from new large load customers. EMW's proposed rate increase is reduced by $61 million because of the presence of anticipated annualized revenues from the LLPS customers, receiving service under the Company's Schedule LLPS tariff.

The sum of these rate adjustments represents a just and reasonable amount necessary to maintain a financially healthy utility that will be well-positioned to continue the investments necessary to maintain safe and adequate service for its customers.

[3] See Order Approving Stipulation & Agreement at 4-5, In re Evergy Missouri West CCN App. Two Solar Facilities, No. EA-2024-0292 (July 31, 2025).

Figure 1: Rate Request Highlights



Q: What steps did the Company take to reduce the rate increase requested in this case?

A: The Company made extensive efforts to bring a substantially higher initial request down to its current level. As Mr. Ives explains, management evaluated the revenue requirement with the objective of balancing customer affordability with the need to maintain safe and adequate service and the Company's financial integrity, and it exercised judgment in selecting reasonable and supportable alternatives that reduced the amount the Company otherwise could have requested. For example, although the Company prepared a new depreciation study, it chose, with only a few necessary exceptions, to recommend continuing the depreciation rates authorized in prior cases, saving customers approximately $26 million in the near term. The Company also removed construction work in progress associated with the Mullin Creek #1 Generation Facility and instead is considering financing construction through a build-to-suit lease, reducing the rate increase by

approximately $31 million, as Company witness Geoffrey Ley (Senior Vice President, Corporate Planning and Treasurer) explains. In addition, the revenue requirement reflects approximately $61 million of projected revenues from new LLPS customers, and the Company's requested 10.25% ROE is at the low end of Ms. Bulkley's recommended range. EMW also offers bill-assistance, flexible billing, weatherization, and energy-efficiency programs for customers facing financial hardship, as discussed by Mr. Ives and Ms. McDonald. These decisions limit the near-term impact on customers while allowing EMW to continue making the investments necessary to provide safe, adequate, and reliable service.

Q: How do net fuel costs contribute to this rate request?

A: Net fuel and purchased power costs are a distinct component of the Company's overall rate request. EMW is requesting the rebasing of net fuel and purchased power costs reflected in its FAC. This increase is separate from the base-rate increase discussed above, which is comprised of the Company's investments, operating costs, financing costs, and other changes in the cost of providing service.

The FAC is designed to reflect changes in eligible fuel and purchased power costs over time. EMW is also requesting continuation of its FAC, and Company witnesses Hsin Foo, JP Meitner, and Linda Nunn provide the detailed support for the fuel and purchased power costs and the operation of the FAC.

Q: What ROE, capital structure, and cost of debt is EMW requesting in this case?

A: Evergy Missouri West requests an ROE of 10.25%. Ms. Bulkley presents in her direct testimony the results of her analysis of equity costs and recommendations in support of an ROE range of 10.25% to 11.25% for Evergy Missouri West. The requested 10.25% ROE

is at the low end of this range and was selected from the range of reasonable returns with customer affordability concerns in mind. With the Company's proposed capital structure of 51.92% equity and 48.08% long-term debt, and its projected average cost of debt of 4.81%, this results in a requested rate of return of 7.64%. The requested ROE, capital structure, and cost of debt are also supported by the testimony of Mr. Ley.

Q: Why is rate structure and design important?

A: There are several reasons why this is important. First, rate structure and design is important to ensure that Evergy Missouri West has a reasonable opportunity to recover its necessary costs of doing business. Second, rate design is necessary to ensure fairness among customers. By this I mean that rates must reasonably apportion the Company's overall costs to the various categories of customers that drive those costs, thereby preventing cross-subsidization between customer classes. Third, an appropriate rate design promotes efficient use of resources by seeking alignment of costs to serve with the provision of accurate price signals to customers. In other words, poorly designed rates may encourage the inefficient use of resources. Finally, innovative rate designs can give customers more choices when they purchase electricity, which allow them to better manage their bills and can result in a more efficient and robust electric system. Key proposals include commercial and industrial ("C&I") demand thresholds, C&I replacement of hours use, C&I optional time of use, and LLPS class cost of service considerations These topics are discussed in more detail by Company witnesses Brad Lutz (Director of Regulatory Affairs) and Graham Jaynes (Manager of Regulatory Affairs).

IV. REGIONAL RATE COMPETITIVENESS

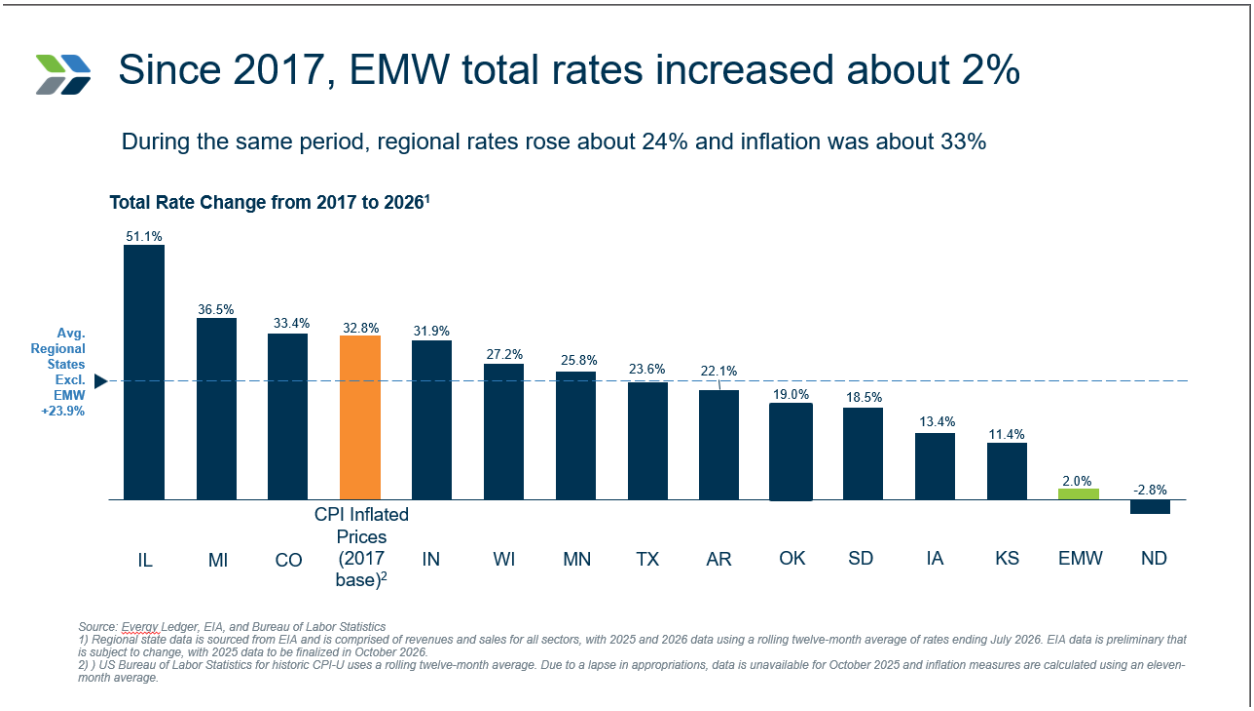
Q: Does Evergy consider the competitiveness of its rates?

A: Yes. Affordability has always been a high priority for the Company, and Evergy recognizes that customers face rising costs for many daily necessities and that electric bills directly affect household budgets. Regional rate competitiveness continues to be a fundamental objective for Evergy and its utilities and is a goal that Evergy shares with the Commission, its customers, and the state of Missouri. As discussed by Mr. Ives and Company witness Katie McDonald (Vice President of Public Affairs), Evergy has worked hard to advance this objective. The result is that Evergy's regional rate competitiveness has improved since the Great Plains Energy-Westar merger in 2018.

Q: What progress has Evergy made to address issues of rate competitiveness?

A: As shown in Figure 2 below, Evergy Missouri West's total rates increased by only 2.0% over the period 2017 through July 2026, while the rates of electric utilities in peer states increased by an average of 23.9% over the same period of time. Also during this period, the cumulative change in inflation was nearly 33%.

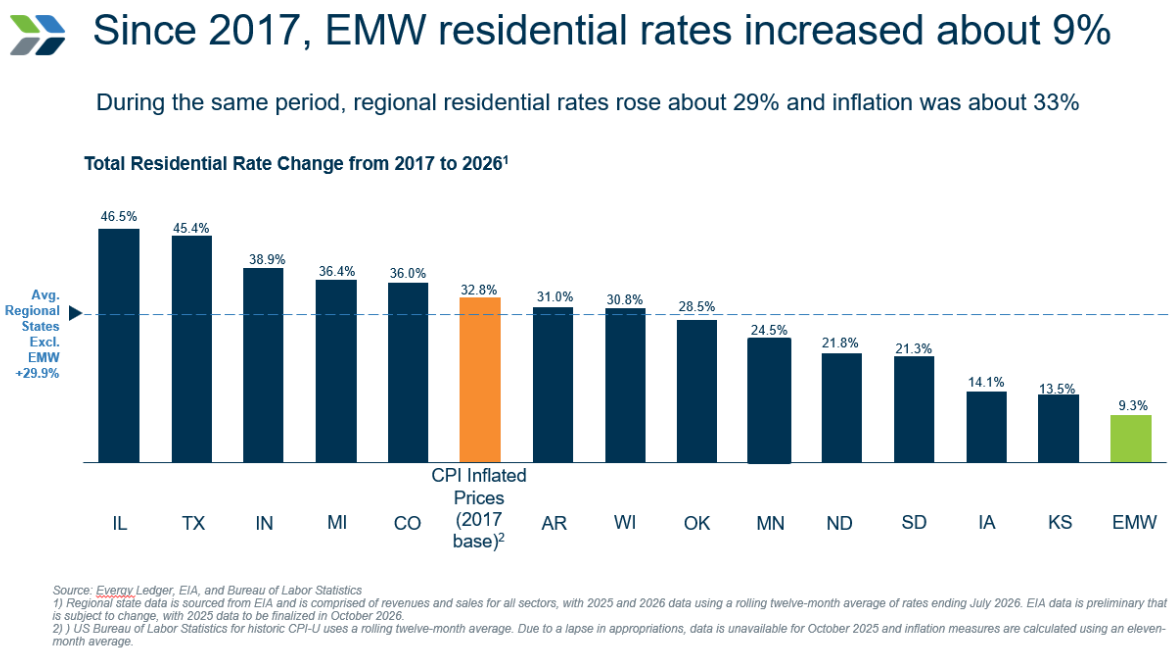
Figure 2: Regional Rate Comparison



Q: Focusing on Evergy Missouri West's residential rates, how do they compare with residential rates in peer states from 2017 through July 2026?

A: As shown in Figure 3 below, EMW's residential rates have continued to be very competitive, as reflected by a 9.3% increase, while regional residential rates on average have increased by 29.9%.

Figure 3: Residential Rate Comparison



Q: Do you expect Evergy Missouri West to continue to improve its competitive rate status in the region?

A: Yes.

Q: How will the rate increase proposed in this case impact Evergy Missouri West's regional rate competitiveness?

A: Given the current rates and pending regulatory proceedings in neighboring states, EMW expects that its rates will remain competitive regionally, even after its rates are increased. If approved by the Commission, this will be the first base rate increase for Evergy Missouri West's customers in more than two years, since its last rate case, Case No. ER-2024-0189,[4]

[4] See Report & Order at 11-12, In re Evergy Missouri West General Rate Increase, No. ER-2024-0189 (Dec. 4, 2024).

and EMW's annualized rate increase since 2017 will continue to compare favorably to regional peer utilities and the rate of inflation.

Q: How does EMW's requested rate increase compare to other utilities around the country?

A: As of mid-October 2026, there were 58 active electric rate cases throughout the country. Among those cases for which comparable information is available, requested rate increases ranged from 2.3% to 50.5%. EMW's requested increase falls in the middle of that range.[5]

V. SECTION 393.130.7 AND LARGE LOAD CUSTOMERS

Q: What is the importance of Section 393.130.7?

A: Section 393.130.7 directs electrical corporations to develop tariffs for new large load customers, ensuring that they pay their share of incremental costs and protecting other customers from unjust and unreasonable rates. These tariffs offer transparent and predictable terms for customers and signal Missouri's capacity to serve large loads on fair, non-discriminatory terms that reduce financial risks for all parties.

Q: Has Evergy developed tariffs pursuant to Section 393.130.7?

A: Yes. As discussed further by Evergy Missouri West witnesses Mr. Gladhill and Mr. Ives, the Commission approved Evergy's Large Load Rate Plan and Schedule Large Load Power Service ("Schedule LLPS"), as modified by the Non-Unanimous Stipulation and Agreement, in Case No. EO-2025-0154.[6] The Commission found that the plan protects existing customers, ensures new large loads pay their share of costs, and drives economic development.[7] The plan provides a transparent framework with clear eligibility, pricing,

[5] Regulatory Research Associates, S&P Capital IQ (last visited January 21, 2026), https://www.capitaliq.spglobal.com/web/client?auth=inherit#industry/pastRateCases?Type=1.
[6] See Report & Order at 46, In re Evergy Request for Large Load Tariffs, No. EO-2025-0154 (Nov. 13, 2025).
[7] Id. at 16-17.

and safeguards, allowing large customers to meet sustainability goals without shifting costs to others. This, combined with Evergy's obligation to serve all customers in its territory, increases Evergy's need for new, efficient resources, similar to those approved by the Commission in Case Nos. EA-2025-0075 and EA-2024-0292, as more large load customers come on-line in the utility's territory.

Q: What are the benefits of attracting new large load customers?

A: New large load customers provide significant benefits to the state, the electrical grid, and existing customers. For the state, they drive economic development through job creation, increased tax revenue, and a more diverse industrial base. For Evergy's customers and its system as a whole, the consistent and predictable consumption of electricity by large load customers supports more efficient grid operation and planning.[8] This phenomenon helps distribute the Company's fixed costs across a greater number of energy consumers which contributes to a lower average cost for all customers.[9]

The Evergy Missouri West Storm Fund provides a particularly clear example of the benefits new large load customers provide to existing customers. Applying the 2026 securitization rates to the energy consumption assumed for new large load customers in this rate case results in approximately $1.8 million of Storm Fund contributions, equivalent to 5.9% of the 2026 total securitization revenue requirement. These customers were not in operation when Winter Storm Uri (February 2021) occurred and therefore did not contribute to the costs giving rise to the storm fund. Nevertheless, as they begin taking service, they contribute toward recovery of those historical costs. Absent these new large

[8] See Report & Order at 9-10, No. EO-2025-0154.
[9] Id.

load customers, approximately $1.8 million would instead be recovered from other EMW customers. Moreover, that benefit is not reflected in the revenue requirement in this case. This provides a concrete example of how attracting new large load customers can reduce the costs otherwise borne by existing customers.

Q: Does Evergy Missouri West currently provide service to any large load customers?

A: No. No customer was taking service under Schedule LLPS during the test year. EMW has signed Electric Service Agreements ("ESAs") with customers and expects them to take service during the true-up period. EMW remains in advanced stages of discussion with additional potential customers.

Q: How has forecasted growth for large load customers been incorporated in this case?

A: The Company has taken a proactive approach to reflect known large load related activity in its revenue projections. As explained by Mr. Jaynes and Mr. Lutz, although there are no large load customers taking service under Schedule LLPS in the test year of the case, retail revenues were adjusted to account for forecasted customer growth using the customers' load forecasts as of the true-up date in this case. As Company witness Mr. Gladhill explains, the large load development process is a continual progression as customers refine plans and progress through the development cycle.

Q: Is any part of the Company's rate request caused by large load customers?

A: There is no net increase in the requested revenue requirement is attributable to projected LLPS service.. Stated plainly, as a result of the customer protections included in the LLPS Rate Plan, Evergy Missouri West customers are already seeing benefits from LLPS customers in its service territory. While no customers are currently served on the Schedule LLPS tariff, Evergy Missouri West reduced its proposed rate request by $61 million based

on projected revenue from new large load customer operations by the true-up date. This is a clear and immediate benefit for Evergy Missouri West customers. This aligns with an Edison Electric Institute ("EEI") published Charles River Associates report in February 2026 that demonstrated that data centers, in particular, are not driving rate increases.[10] Matthew DeCourcey, Vice President of the Energy Practice at Charles River Associates, stated: "There is no evidence to support the idea that data centers have made rates go up."[11] Specifically, rates have been stable across most of the country, including Missouri, where current rates have been unaffected by data centers as compared to the Northeast and California.[12]

A subsequent update to the report published in October 2026 finds "additional evidence that utilities and state regulators have acted quickly to adopt many of the best practices identified in *Retail Rate Trends* to protect customers from negative impacts when data centers are added to the electric grid."[13]

This position, as supported in the Charles River Associates reports, is consistent with the rate design and customer protections in the LLPS Rate Plan that EMW filed and the Commission approved in Case No. EO-2025-0154.[14]

[10] Matthew DeCourcey & Mayank Saraswat, *Retail Rate Trends in the US*, Charles River Associates at 3 (Feb. 2, 2026).
[11] Drew Maloney & Matthew DeCourcey, *Electric Perspective*, Edison Electric Institute (Feb. 2, 2026).
[12] Matthew DeCourcey & Mayank Saraswat, *Retail Rate Trends in the US*, Charles River Associates at 8 (Feb. 2, 2026).
[13] Matthew DeCourcey & Mayank Saraswat, *Retail Rate Trends in the US: Fall 2026 Updat*e, Charles River Associates at 2 (Oct. 19, 2026).
[14] See Report & Order at 9-10, 16-17.

Q: Are there any customers receiving discounted electric rates under the Economic Development Rider ("EDR")?

A: Yes. Customers receiving discounted electric rates under the Company's EDRs are included in the projected true-up period.

Q: What is the EDR?

A: The Company offers two economic development riders. Schedule PED is the Company's Limited Large Customer Economic Development Discount Rider which implements Section 393.1640.[15] The Company's Economic Development Rider is designed to encourage industrial and commercial development in Missouri and to retain existing load.16 It discounts the base rate portion of a qualifying new load's electric service bill.

Q: What public policy objectives does the EDR serve?

A: The EDR is designed to bring in load that would otherwise locate somewhere else. Because a customer must certify that it would not locate or expand here but for the discount, and must also be receiving government economic development incentives, the discount goes to projects that are still weighing other sites. Other customers are protected by the rate floor. EDR load has to cover the Company's variable cost and contribute to fixed costs, and if a later rate case shows it does not, the Commission can adjust the discount. The communities the Company serves gain the new investment, jobs, and tax base that come with that load.

Q: How are EDR discounts treated for ratemaking purposes?

A: The revenue requirement includes a normalized level of EDR credits. Mr. Jaynes describes the process in additional detail.

[15] See EMW Limited Large Customer Economic Development Discount Rider Schedule PED, Revised Sheet No. 155 (May 10, 2023).
[16] See EMW Economic Development Rider, Revised Sheet No. 123.1 (Nov. 8, 2016).

VI. PROPOSED MECHANISMS AND OTHER REQUESTS OF THE COMMISSION

A) PLANT IN SERVICE ACCOUNTING

Q: What is plant in service accounting ("PISA")?

A: PISA is a mechanism that allows utilities to defer a portion of the depreciation expense and return associated with qualifying plant placed in service between rate cases to a regulatory asset for recovery in the next general rate case.[17] It addresses regulatory lag, under which utilities would otherwise have to wait until the next rate case to include new investments in rate base.

Q: What are some of the distribution system investments that are part of the Company's capital plan and will be supported by PISA?

A: As discussed further by Mr. Mulvany, the distribution investments include:

- The Distribution System Performance Program;
- The Distribution Pole Replacement and Reinforcement Program;
- The Proactive Cable Replacement/Rehabilitation Program;
- The Underground Distribution Replacement Program;
- The High Outage Count Customers Program; and
- The Customers Experience Multiple Interruptions Improvement Program

Q: How does PISA affect rates and influence investment planning for grid modernization?

A: The negative lag inherent in traditional ratemaking, where cost recovery for capital investments is delayed until the next rate case, has made it difficult for EMW and other Missouri electric utilities to invest at the level needed to accelerate grid modernization for

[17] See Section 393.1400.

the benefit of customers. Section 393.1400 allows Evergy Missouri West to use PISA to offset a portion of this negative lag. This has allowed the Company to increase investment in its distribution system to improve reliability. By reducing regulatory lag, PISA enables more timely investment in critical infrastructure, enhancing system resilience and providing tangible benefits to customers through improved service reliability. It also helps align the recovery of costs with the delivery of these benefits to reduce rate impacts on customers because Section 393.1656 requires the Company to limit the revenue requirement impact of PISA through an impact cap.

B) CONSTRUCTION WORK IN PROGRESS

Q: What does Section 393.135.2 provide regarding construction work in progress ("CWIP")?

A: As described in Mr. Klote's direct testimony, Senate Bill 4's Section 393.135.2(1) permits electrical corporations "to include construction work in progress for any new natural gas-generating unit in rate base."[18] The inclusion of CWIP "shall be in lieu of any otherwise applicable allowance for funds used during construction that would have accrued from and after the effective date of new base rates."[19] When evaluating CWIP, the Commission "shall determine" in a CCN proceeding pursuant to Section 393.170 the amount of CWIP that may be included in rate base "limited by: (a) The estimated cost of such project; and (b) Project expenditures made within the estimated construction period for such project."[20]

[18] See Section 393.135.2(1)
[19] Id.
[20] Id.

As stated by Governor Kehoe when he signed Senate Bill 4, CWIP "[i]ncentivizes new power generation facilities and reduces financing costs, saving Missourians money in the long run and expanding Missouri's electrical grid capacity."[21]

Q:What benefit does CWIP provide to Evergy Missouri West in this rate case?

A: As discussed by Mr. Klote, EMW is including CWIP related to three new natural gas-fired generation facilities necessary to meet customer demand and reliability requirements within EMW's service territory. As discussed, EMW received CCNs for its 50% ownership interests in the Chisholm Trail and McNew natural gas energy centers in Case No. EA-2026-xxxx5. Additionally, on August 31, 2026, the Company filed a CCN application in Case No. EA-2026-0343 seeking approval for the construction and operation of a new combined-cycle gas turbine generating facility known as Buchanan Bluffs Energy Center Unit 2, in which EMW would hold a 50% ownership interest.22

Given this, including CWIP in rate base in this case will allow EMW to recover the financing costs of constructing these three natural gas facilities gradually, as those costs are incurred. Without CWIP in rate base, all construction financing costs would accumulate (and incur financing costs on financing costs) until the facilities are completed and placed in service and the Commission authorizes their recovery, allowing EMW to earn a return on its investment. By spreading these costs over the construction period, the inclusion of CWIP in rate base reduces the rate increase customers would otherwise experience when the facilities go into service, which lowers rates over the long term.

[21] See *Governor Kehoe Signs SB 4 Into Law, Securing Missouri's Energy Future and Economic Growt*h, Media Release (Apr. 9, 2025).
[22] See App. In re Evergy CCN App. Regarding Natural Gas Facility and Battery Energy Storage System, No. EA-2026-0343 (Aug. 31, 2026).

C) EARNINGS REVIEW SHARING MECHANISM

Q: Is EMW proposing an earnings review and sharing mechanism?

A: Yes. EMW proposes a temporary Earnings Review Sharing ("ERS") mechanism to provide additional customer protection as Schedule LLPS service develops between this case and the effective date of rates in EMW's next general rate case. The proposal is based on the framework filed in EMM's pending rate case (Case No. ER-2026-0143), adapted to EMW's circumstances. In their direct testimonies, Mr. Ives explains the policy basis for the proposal, and Mr. Klote explains its operation and detailed terms.

Q: Under what circumstances would the ERS require earnings to be shared with customers?

A: Sharing would occur only if two conditions are met: (1) EMW's earned return on equity exceeds its authorized return by more than 20 basis points, a deadband, and (2) actual Schedule LLPS base rate revenues exceed the LLPS revenues reflected in the revenue requirement used to establish rates. If both conditions are satisfied, 65% of the calculated earnings above the deadband would be deferred for customers and 35% retained by EMW. The portion of the customer share exceeding 50% would benefit low-income customers. Mr. Ives addresses why this balance is appropriate, while Mr. Klote provides the calculation and accounting details.

Q: How would the ERS protect customers while preserving EMW's financial incentives?

A: The ERS would provide customers a share of favorable results attributable to significant LLPS growth, while allowing EMW to retain ordinary earnings variation within the 20 basis point deadband and a minority share of earnings above it. The customer share would be recorded as a regulatory liability and returned through an amortization established by

the Commission, with special treatment for amounts attributable to PISA. Annual reports, discovery, Staff and OPC review, and Commission resolution procedures would provide the necessary transparency and oversight for the ERS. Mr. Ives discusses the policy and customer-protection rationale, and Mr. Klote and Schedule RAK-5 provide the detailed reporting, review, and return provisions.

D) CYBER TRACKER

Q: Why is Evergy Missouri West requesting a Critical Infrastructure Protection ("CIPS")/Cyber Security Tracker ("Tracker")?

A: As discussed further by Company witnesses Ronald Klote (Senior Director – Regulatory Affairs) and Charles King (Senior Vice President, Chief Technology Officer), the security threat landscape is accelerating, with adversaries targeting the electric grid at all voltage levels and leveraging sophisticated attack vectors including nation-state campaigns, supply chain compromises, and ransomware. Recent events underscore these risks, including the 2017 Russian infiltration of U.S. nuclear networks and Chinese intrusions into large U.S. carrier networks, as well as Evergy's own need to engage external security consultants when third-party compromises required rapid network assurance. The requested Tracker would permit timely recovery of unpredictable and substantial non-labor operation, maintenance and related costs outside of base rates, enabling swift, flexible responses to serious threats, as well as evolving federal reporting and compliance mandates. This flexibility is in the public interest because it supports safe, adequate, and reliable service at just and reasonable rates by allowing Evergy Missouri West to deploy prudent, layered defenses beyond baseline compliance as threats evolve.

Q: How will customers benefit from the Tracker?

A: Customers will benefit through improved reliability and resiliency, as the Company prepares for and responds to disruptions from both cyber actors and physical threats by using processes, tools, and spare parts designed to shorten restoration times, particularly amid longer supply-chain lead times. Compliance remains the baseline, but Evergy Missouri West employs a defense-in-depth strategy to mitigate evolving risks, including threats to widely dispersed unmanned assets (e.g., from drones) and supply chain exposures, such as embedded malicious components. To prudently manage these expenses, EMW will track the costs through specific accounts for Commission Staff to review in future rate cases. The Company will exclude internal labor for current employees.

E) INJURIES AND DAMAGES RESERVE

Q: What is Evergy Missouri West's request for an Injuries and Damages reserve?

A: The Company proposes to establish an Injuries and Damages ("I&D") reserve to address the inherent unpredictability and magnitude of costs arising from these claims, rather than attempting to forecast when and in what amounts such expenditures will occur. Evergy Missouri West witness Mr. Klote describes the request for this reserve in more detail.

An I&D reserve would also strengthen the Company's risk management posture by ensuring that funding is available for adverse outcomes, thereby reducing earnings volatility and mitigating the need for abrupt rate adjustments.

F) STORM RESERVE

Q: Why is Evergy Missouri West requesting a storm reserve?

A: The proposed storm reserve will reduce rate volatility for customers by using levelized expenditures associated with significant storms. This will lessen the financial impact by smoothing month-to-month storm expenditures associated with unpredictable and significant storm events. The storm reserve allows the Company to focus on service restoration and not on the financial implications as costs will be spread over time. Mr. Mulvany and Mr. Klote discuss this request in their direct testimony.

VII. FUEL ADJUSTMENT CLAUSE RECOMMENDATIONS

Q: Does the Company have an approved fuel adjustment clause?

A: Yes. EMW's FAC was initially approved in Case No. ER-2007-0004 on May 17, 2007, and has been modified and clarified in subsequent rate cases. Ms. Nunn addresses the Company's FAC and demonstrates that EMW has met the filing requirements of Section 386.266 and Commission rule 20 CSR 4240-20.090(2).

Q: What is the Company recommending with respect to the design of its FAC in this case?

A: EMW makes two current requests and one future recommendation. The first current request is that the Commission eliminate the 95/5% sharing percentage currently applied to net fuel and purchased power costs recovered through the FAC, under which the Company absorbs a fixed share of the variance from the base amount set in rates. The second current request is that the Commission allow EMW to include eligible long-term purchased capacity costs in the FAC reconciliation instead of recovering those costs solely through base rates. Finally, as a future recommendation, the Commission should consider allowing all net fuel

costs to be recovered through the rider on an ongoing basis, rather than limiting rider recovery to the amounts captured in the periodic true-up.

With respect to the future recommendation, I will discuss the Commission's authority to approve those changes and the longer-term policy objective of converting Missouri's FAC from a base-rate reconciliation mechanism to a comprehensive fuel and purchased-power tracking mechanism. Company witness Linda Nunn addresses the proposed tariff language, accounting, calculations, allocation, and implementation details.

A) FAC REQUEST 1: ELIMINATION OF THE 95/5% RISK SHARING

Q: What is the basis for EMW's request to eliminate the 95/5% sharing mechanism?

A: EMW's current FAC design, including its sharing mechanism, was developed for a materially different operating environment. A sharing mechanism rests on the premise that a utility can meaningfully influence its net fuel and purchased power costs, so that retaining a portion of cost variances creates an incentive for efficient management. That premise no longer holds for EMW. Today, centrally dispatched Southwest Power Pool ("SPP") market outcomes, evolving resource-adequacy requirements, regional transmission costs, and large load growth drive a greater share of EMW's net power-supply costs, and these drivers are largely outside EMW's control. The Commission recognized as much in its Report and Order approving EMW's new natural gas generation. SPP has significantly increased its planning reserve margins to 36% in the winter and 16% in the summer, which increases the amount of capacity EMW must secure to serve its peak load.[23]

Because those increased requirements apply to all SPP members at the same time that demand is growing at an unprecedented rate, the Commission found that the bilateral

[23] See Report & Order at 12, No. EA-2025-0075.

capacity market is no longer a viable long-term option and that the excess capacity market is becoming unviable.[24] EMW therefore faces a capacity deficit the Commission described as "dire" at the very moment the market it has historically relied on is tightening.[25] Until its new generation comes online, EMW has no practical alternative to meeting a significant portion of its customers' needs through SPP market purchases, which the Commission found expose EMW to pricing risk, as Winter Storm Uri and EMW's significant fuel and purchased-power losses since 2019 demonstrate.[26] Continued large load growth will only increase that exposure.

Under these circumstances, the sharing mechanism does not reward prudent management. Rather, it penalizes EMW for market-driven cost variances it cannot avoid, while the Commission has already confirmed that EMW is taking the long-term steps needed to reduce its market reliance. Eliminating the sharing mechanism and providing full reconciliation and timely recovery of net fuel and purchased-power costs would better align recovery with cost causation while preserving customer protection through prudence review, audit, true-up, reporting, and Commission oversight.

Q: How were fuel and purchased power costs recovered before Missouri authorized FACs?

A: Before 2005, Missouri electric utilities generally recovered fuel and purchased power costs through base rates established in general rate cases. Following the Missouri Supreme Court's 1979 decision invalidating automatic fuel surcharges under the statutes then in effect, changes in those costs remained with the utility until rates were reset in a subsequent

[24] Id. at 11, 35.
[25] Id. at 9, 13, 15, 32-33.
[26] Id. at 9, 11-12.

case.[27] That framework created substantial regulatory lag and exposed utilities and customers to forecast error and volatile market conditions.

Q: What changed in 2005?

A: The General Assembly enacted Section 386.266, authorizing the Commission to approve periodic rate adjustments outside general rate proceedings for increases and decreases in prudently incurred fuel and purchased power costs, including transportation. The statute established safeguards including true-ups, prudence reviews, reporting, and periodic return to a general rate case. It also authorized—but did not require—the Commission to include features designed to improve the efficiency and cost-effectiveness of fuel and purchased power procurement.

Q: How did EMW's 95/5% sharing mechanism originate?

A: In Aquila, Inc.'s 2007 rate case, Case No. ER-2007-0004, the Commission approved the first statutory FAC for EMW's predecessor. The Commission sought to reduce regulatory lag while retaining an economic incentive for procurement and operating efficiency. It therefore allowed customers to receive or pay 95% of eligible variances and required the utility to retain or absorb the remaining 5%. That design was a policy judgment based on the record and operating conditions then before the Commission. It was not a percentage required by Section 386.266.

Q: What assumptions supported that design?

A: The approach assumed a meaningful relationship between management decisions and the cost variances to which sharing applied. At that time, utility-controlled generation dispatch, fuel procurement, bilateral purchases and sales, and other operating decisions had a more

[27] See State ex rel. Utility Consumers Council of Missouri, Inc. v. PSC, 585 S.W.2d 41 (Mo. banc 1979).

direct effect on net fuel and purchased power costs. A symmetrical share of favorable and unfavorable variances was intended to provide "skin in the game" where management could materially affect the outcome.

Q: How have those operating principles changed?

A: The SPP Integrated Marketplace, which began operations in 2014, fundamentally changed dispatch and settlement. SPP centrally commits and dispatches resources, establishes market-clearing prices, and allocates many regional market and transmission charges. EMW continues to make important integrated resource planning, procurement, hedging, bidding, and operational decisions, but a larger share of FAC outcomes now reflects congestion, regional dispatch, reserve requirements, accreditation rules, weather, transmission conditions, and other market outcomes that EMW cannot control. The original link between a broad sharing percentage and controllable performance has therefore weakened.

Q: Why are large load customers another catalyst for change?

A: LLPS customers can change demand in increments and on timelines that were not contemplated when the FAC was established. Energization dates, ramp schedules, and ultimate usage may differ materially from rate-case forecasts. At the same time, EMW may need to secure energy and accredited capacity in advance to satisfy SPP reliability requirements. Those timing differences can create substantial FAC variances even where the Company has planned and procured prudently. A fixed 5% exposure does not improve the timing of a customer's ramp or change SPP's requirements. Rather, it simply transfers a portion of those risks to shareholders.

Q: Does the Commission have authority to change the FAC sharing percentage?

A: Yes. Section 386.266 authorizes periodic adjustments for prudently incurred fuel and purchased power costs and permits the Commission to include incentive features. It does not mandate a sharing mechanism or prescribe a 95/5% allocation. The Commission's FAC rule, 20 CSR 4240-20.090, provides the procedural framework for establishing, continuing, or modifying an FAC in a general rate proceeding. Accordingly, the Commission may determine on the record in this case that 100/0% reconciliation, together with existing prudence and true-up protections, is just and reasonable.

Q: Why should the Commission replace that mechanism with 100/0% reconciliation?

A: Broad sharing is no longer well matched to the costs and risks flowing through the FAC. When SPP determines commitment, dispatch, market prices, congestion outcomes, and regional requirements, EMW cannot systematically "beat" the market through its own dispatch. Applying a 5% penalty to prudent costs driven by those outcomes does not create an efficient incentive. It is a risk transfer unrelated to controllable performance.

Q: Is EMW an outlier?

A: Yes. As provided in Schedule KDG-1, is a report prepared by Concentric Energy Advisors in which the Company had a review conducted of FAC mechanisms across the country to review regulatory methods utilized to incorporate fuel expense in customer rates. It found that 20 of 33 traditionally regulated states, or approximately 61%, fully reconcile fuel and purchased power-related costs without broad risk sharing. Missouri is one of only two states identified that participate in an organized regional market and apply broad percentage sharing to fuel and purchased power variances. Other organized-market jurisdictions more commonly limit sharing to off-system sales or other revenues, or use

targeted bands, earnings tests, or cost-specific mechanisms. Missouri's broad 95/5% design is an outlier.

Q: Why does the Company describe the current combination of SPP market design and FAC sharing as punitive?

A: SPP dispatches the regional system to achieve economic and reliability objectives, and EMW must settle at the resulting prices and comply with regional requirements. The FAC then requires EMW to absorb 5% of eligible variances even when they arise from congestion, extreme weather, reserve-margin changes, transmission conditions, or unanticipated large-load timing. Where the Company cannot change the underlying outcome, sharing ceases to function as an incentive and becomes a penalty on prudent performance.

Q: Would full reconciliation remove customer protections?

A: No. Prudence review directly tests whether management acted reasonably and permits disallowance of imprudent costs. FAC audits, true-ups, reporting, tariff eligibility rules, and Commission oversight would also remain. These protections are better targeted than an automatic 5% allocation that applies regardless of whether the Company acted prudently.

Q: What does the Company recommend?

A: The Company recommends 100% reconciliation of eligible, prudently incurred FAC costs and revenues. That change is consistent with the predominant benchmark practice, better aligned with SPP market operations, and responsive to the magnitude and timing uncertainty introduced by large load growth. Changing to 100% reconciliation of both favorable and unfavorable variances would allow customers to receive the full benefit of

eligible reductions as well as bear the full amount of eligible increases, subject to prudence review.

Q: If the Commission declines to eliminate the current sharing mechanism, what level of sharing should remain?

A: The Company proposes that, if the Commission does not adopt 100% reconciliation, it retain the existing 95/5% sharing level.

B) FAC REQUEST 2: INCLUSION OF LONG-TERM CAPACITY COSTS IN EMW'S FAC

Q: What is the Company proposing with respect to inclusion of long-term capacity costs in EMW's FAC?

A: EMW proposes to include eligible long-term purchased capacity costs in the FAC reconciliation instead of recovering those costs solely through base rates. Ms. Nunn describes the qualifying costs, exclusions, allocation, tariff language, and reconciliation mechanics.

Q: Why is base rate only recovery no longer sufficient?

A: EMW must maintain sufficient accredited capacity to serve customers and satisfy SPP resource-adequacy requirements. The need for a multi-year capacity purchase may arise between rate cases because of large load additions, accreditation changes, reserve-margin requirements, retirements, or constrained regional supply. Waiting until the next rate case creates regulatory lag and may expose the Company to substantial prudent costs for capacity already being used to serve customers.

Q: How would FAC treatment improve procurement decisions?

A: Comparable recovery treatment allows EMW to evaluate short-term and long-term capacity alternatives on cost, risk, term, and reliability value rather than on whether

recovery will be delayed. A longer-term contract may be less costly or less risky than repeated short-term purchases. FAC eligibility therefore supports least-cost procurement while preserving prudence review.

Q: Is FAC recovery of long-term capacity costs unusual?

A: No. The benchmarking report identifies several accepted approaches. AES Indiana uses a dedicated capacity rider; Colorado utilities use purchased-capacity mechanisms; Kentucky Power reconciles purchased energy and capacity variances; and other jurisdictions recover capacity through fuel, power-cost, or resource-adequacy mechanisms. The mechanisms differ, but timely recovery of prudently incurred purchased capacity outside base rates is established regulatory practice.

Q: Why include these costs in the FAC rather than create a separate rider?

A: The FAC already provides a transparent process for tracking, filing, audit, prudence review, true-up, recovery, and refund. Purchased capacity is part of the net power-supply portfolio required to serve load and is closely related to purchased energy and SPP resource-adequacy obligations. Using the existing mechanism avoids duplicative administration while allowing the Commission to define eligibility precisely.

Q: Does the Commission have authority to include long-term purchased capacity costs?

A: The Commission has authority to determine which prudently incurred fuel and purchased power cost components qualify for recovery within the statutory and regulatory framework. The legal question is whether the proposed long-term capacity charges are properly treated as purchased-power costs incurred to serve load, rather than as costs outside Section 386.266. The Commission excluded purchased power demand costs from Aquila, Inc.'s original FAC in 2007, but that decision applied the statute to the record and market

conditions then presented. It did not amend the statute or permanently foreclose a different determination of long-term capacity contracts. Ms. Nunn explains the specific cost definition and tariff controls supporting inclusion here.

Q: What limits remain on the Commission's authority?

A: Any modification must remain within Section 386.266, the Commission's rules, and the filed record. Eligible costs must be prudently incurred fuel or purchased power costs, including authorized related items. The FAC must retain required true-up, prudence-review, reporting, and rate-case safeguards, and EMW's rates must remain just and reasonable. Those limits support careful definition and review of long-term capacity costs, but they do not require continuation of 95/5% sharing.

C) FAC RECOMMENDATION 3: A TOTAL RECOVERY OF UTILITY ENERGY COSTS FAC ("TRUE FAC")

Q: Please describe the recommendation to move all fuel and purchased power costs into a separate rider.

A: A more comprehensive cost recovery mechanism for fuel and purchased power related costs would move all approved fuel and purchased power related costs out of base rates and into a separate tracking mechanism where costs are forecasted and reconciled on an annual basis. The mechanism would establish a prospective fuel and purchased power factor, compare actual eligible costs and revenues with that forecast, and periodically refund or recover the difference. It could include fuel, purchased energy, purchased capacity, eligible SPP and transmission charges, hedging, ancillary services, and defined offsets such as off-system sales and renewable-energy-credit revenues.

Q: Why should all net fuel costs move into the rider rather than only the true-up amounts?

A: Recovering only the true-up amounts through the rider leaves a structural mismatch between when fuel costs are incurred and when they are recovered. Base rates carry a fuel level fixed at the time of the last rate case, and that level begins diverging from actual cost the day new rates take effect. The rider then corrects the divergence only in arrears and only in part. Moving all net fuel costs into the rider aligns recovery with actual cost in the period the cost is incurred, which reduces the deferral balances that customers ultimately pay carrying costs on and removes the incentive to file rate cases for the purpose of resetting the base fuel level.

Q: How would that differ from the current FAC?

A: The current mechanism begins with fuel and purchased power amounts embedded in base rates and reconciles eligible variances from that base until the next rate case. A full tracker would not only recover the approved category of net power supply costs through one dedicated mechanism rather than dividing the same costs between base rates and the FAC, but would also change the cost-setting framework from historical to prospective. This approach would reduce the significance of an increasingly stale base factor, improve transparency, and eliminate the need to litigate base fuel costs within a general rate case proceeding.

Q: In the Company's review of FAC mechanisms across the United States, is a separate fuel cost rider the most widely accepted approach?

A: Regular updating of fuel and purchased power charges between rate cases is the predominant approach As explained in Section 4 of Schedule KDG-1, most traditionally

regulated states use forward-looking estimates or update the fuel rate to reflect current or forecasted costs between rate cases. Missouri is in the minority in reconciling actual fuel costs against a fixed base established in a general rate case. Several states recover the entirety of fuel costs outside base rates through a separate fuel cost proceeding. These findings support consideration of a separate rider while also supporting the broader practice of regularly updating fuel costs.

Q: How would this change affect customers?

A: Customers would see fuel costs reflected closer to when those costs are actually incurred, rather than through a lagging correction. The change affects the timing and allocation of recovery. It does not increase the total fuel cost customers pay. The existing protections are unaffected: the FAC remains subject to prudence review, to the periodic true-up, and to the rate case review cycle required by Section 386.266.

Q: What customer protections should accompany a full tracker?

A: The mechanism would retain prudence review, audit rights, periodic true-ups, carrying-cost rules, transparent tariff definitions, reporting, cost-allocation requirements, and Commission approval of forecast changes. The Commission could also consider materiality thresholds, rate-smoothing, or limits on recovery-period changes where needed to address customer rate impacts without denying recovery of prudent costs.

Q: Could the Commission implement that complete design under current law and rules?

A: The Commission can modify an FAC within the authority granted by Section 386.266 and can revise its implementing rules through rulemaking. However, a full tracker that removes all fuel and purchased power related costs from base rates, broadens covered categories, and operates independently of the existing base factor and rebasing structure would present more substantial statutory and regulatory questions than the two other FAC changes

proposed (elimination of risk sharing and inclusion of long-term capacity costs). This path is a longer term solution that would most likely require coordinated legislation and rulemaking.

Q: Does that longer-term objective affect the relief requested in this case?

A: No. The Commission can and should address the present mismatch now by eliminating the 95/5% sharing mechanism and including eligible long-term capacity costs in the FAC. A comprehensive tracker is a longer-term modernization initiative that should proceed through a deliberate legislative and rulemaking process.

VIII. CROSSROADS ENERGY CENTER

Q: What is the Company requesting with respect to Crossroads in this case?

A: As discussed in Mr. Ives' direct testimony, EMW asks the Commission to approve "Path A" finding that the delivered cost of Crossroads, including the transmission expense EMW incurs today, is reasonable and be included in EMW's cost of service for all customers, effective with the rates set in this case. Path A asks the Commission to decide the question it reserved in Case No. ER-2024-0189 for a general rate case. Only if the Commission does not adopt Path A does EMW request, in the alternative, "Path B," under which Crossroads and its costs would be assigned to Schedule LLPS customers once a customer begins taking service under that schedule. I refer the Commission to Mr. Ives and Mr. VandeVelde's direct testimony for more discussion and support of the Company's Crossroads request in this case.

IX. CONCLUSION

Q: Please summarize your testimony.

A: EMW is committed to providing exceptionally safe, reliable, and affordable utility service to its customers. The Company has worked hard to manage costs, maintain regional rate competitiveness, and prepare for growing customer demand, including from new large load customers.

Taking these steps and utilizing prudent cost tracking mechanisms — such as PISA treatment, a cyber security tracker, the injuries and damages reserve, the storm reserve, and the inclusion of CWIP in rate base — will ensure timely cost recovery, reduce rate volatility, and support prudent long-term planning for the benefit of all customers. These mechanisms will provide the foundation on which EMW will execute its strategic plans for the future.

EMW requests that the Commission continue its FAC, eliminate the 95/5% sharing mechanism, and allow eligible long-term purchased capacity costs to be included in the FAC reconciliation rather than recovered solely through base rates. These changes reflect an operating environment in which SPP market outcomes, rising resource-adequacy requirements, and large load growth, all largely outside EMW's control, drive net power-supply costs, so the sharing mechanism penalizes EMW for unavoidable cost variances rather than incentivizing efficient management. Looking ahead, EMW also recommends that the Commission consider converting the FAC into a comprehensive fuel and

purchased-power tracking mechanism, while customers remain protected through prudence review, audit, true-up, and Commission oversight.

Finally, consistent with the Commission's prior determinations that Crossroads is a prudent resource and its more recent finding that renewing the Crossroads transmission agreements is the lowest-cost option for EMW and its customers, the Company recommends that the Commission find the delivered cost of Crossroads, including its transmission expense, reasonable and include that cost in EMW's cost of service, effective with the rates set in this case.

Q: Does that conclude your testimony?

A: Yes, it does.

REVIEW AND ASSESSMENT OF FUEL AND PURCHASED POWER MECHANISMS

CONFIDENTIAL PREPARED AT THE REQUEST OF COUNSEL

PREPARED FOR:
EVERGY MISSOURI WEST

NOVEMBER 3, 2026

CONCENTRIC ENERGY ADVISORS

CEADVISORS.COM

©2026 CONCENTRIC ENERGY ADVISORS, INC. All rights reserved.

TABLE OF CONTENTS

Table of Contents i

Section 1: INTRODUCTION AND SUMMARY 1

Section 2: CURRENT FAC FRAMEWORK IN MISSOURI 2

Section 3: FACs ACROSS THE UNITED STATES 12

Section 4: FUEL COST REBASING 19

Section 5: LARGE LOADS and FUEL ADJUSTMENT CLAUSES 22

Appendix A: Fuel and Purchased Power Adjustment Mechanism Risk Sharing 1

SECTION 1:

INTRODUCTION AND SUMMARY

Evergy Missouri West (EMW or the Company) is reviewing its Fuel Adjustment Clause (FAC) in light of changes in its operating environment and cost profile. Relevant developments include EMW's participation in the Southwest Power Pool, changes in regional transmission and market costs, and potential large-load growth in Missouri. This report describes FAC mechanisms across traditionally regulated jurisdictions and presents benchmark examples for EMW's consideration in evaluating its FAC design.

FACs are widely used by investor-owned electric utilities, but their design varies materially across traditionally regulated, vertically integrated jurisdictions. This review focuses on 33 such states and finds that most do not use broad fuel-cost risk sharing: 20 of the 33 states reviewed fully reconcile fuel and purchased power-related costs without requiring the utility or customers to absorb a fixed percentage of variances. Among the remaining 13 states with some form of risk sharing, the mechanisms vary by cost category, market structure, deadband, earnings test, recovery timing, and treatment of market revenues. This comparison shows that Missouri's statewide 95/5 sharing approach is not the predominant model among traditionally regulated states.

The national benchmark shows that customer protection does not depend on a single fuel-cost sharing percentage; jurisdictions use prudence reviews, true-ups, deadbands, earnings tests, and cost-assignment tools to balance recovery and accountability.

In addition to comparing fuel and purchased power cost risk-sharing provisions, the types of costs included in fuel adjustment mechanisms, and the methods used to establish and reconcile base fuel costs, this report reviews jurisdictions in which large-load tariffs are in place or have been proposed. The review provides some recent examples of large load tariffs and treatment of FAC-related costs.

The benchmark identifies FAC design alternatives that differ from EMW's current approach, including mechanisms that distinguish among cost categories, use deadbands or earnings tests, limit sharing to selected revenues or variances, or separately address transmission, capacity, and large-load-related costs. These findings provide comparative information for EMW's assessment of whether and how its FAC design reflects the characteristics of the costs included in the mechanism.

SECTION 2:

CURRENT FAC FRAMEWORK IN MISSOURI

HISTORY OF FAC

Missouri's FAC framework was authorized in 2005 and implemented in 2007 through Section 386.266, RSMo., which allowed electric utilities to recover prudently incurred fuel and purchased power cost variances outside a general rate case, subject to Commission approval, true-ups, prudence review, reporting, and periodic rebasing.

The original framework reflected a compromise that reduced regulatory lag and fuel-cost volatility while preserving an incentive for efficient fuel procurement and purchased power management. Missouri implemented that incentive through a 95% customer / 5% utility sharing mechanism first approved for Aquila, EMW's predecessor, and later applied in similar form to Missouri's other electric utilities.

SERVING CUSTOMER LOAD

EMW's FAC begins with base fuel and purchased power costs established in a general rate case (GRC). Actual eligible costs are then compared to that base level, and 95% of the resulting variance is recovered from or returned to customers through future FAC rates.

Resource planning, including the IRP process, informs the generation and purchased power portfolio used to serve customer load, but the FAC reconciles the difference between forecasted base energy costs and actual costs incurred as operating conditions change. Base energy costs are rebased within a GRC, with intervals between rebasing typically ranging from 2 to 4 years.

Eligible FAC costs include fuel for utility-owned generation, purchased power energy costs, certain SPP market costs, emission allowance costs, and related offsets such as off-system sales revenues and REC revenues.

Transmission costs also flow through the FAC when tied to purchased power or off-system sales. Regional transmission costs may differ from variable fuel and purchased energy costs in their underlying drivers, timing, and degree of utility control.

Because the FAC measures actual costs against a base level established in a rate case, changes in fuel prices, market purchases, load, transmission charges, and weather can create over- or under-recoveries. Under the current 95/5 mechanism, customers are responsible for 95% of those variances and EMW retains or absorbs 5%. Table 1 below provides an overview of the variances over the past six accumulation periods.

Table 1: Evergy Missouri West FAC Variances by Accumulation Period

Accumulation Period	Base Costs ($)	Actual Costs ($)	Variance: Actual less Base ($)	Jurisdictional Factor	95% Customer Amount ($)	5% Risk Sharing Amount ($)	Reason for Variance
33rd AP: June-November 2023	$137,973,113	$140,873,518	$2,900,405	99.74310%	$2,748,306	$144,648	Higher summer load and warmer-than-normal weather increased purchased-power requirements. Relative to the prior period, fuel costs increased $12.9 million, purchased-power expense increased $2.1 million, and off-system sales revenue declined $1.2 million.
34th AP: December 2023-May 2024	$124,225,291	$117,620,217	($6,605,074)	99.70624%	($6,256,387)	($329,284)	Warmer winter weather and lower retail load reduced energy requirements. Relative to the prior period, fuel costs declined $14.6 million and purchased-power expense declined $11.5 million, partly offset by a $2.4 million reduction in off-system sales revenue. Lower natural-gas prices also reduced purchased-power requirements.
35th AP: June-November 2024	$135,808,617	$109,918,922	($25,889,695)	99.80401%	($24,547,006)	($1,291,948)	Purchased-power expense declined $22.3 million relative to the prior period. This was partly offset by an $8.4 million increase in fuel costs and a $5.7 million reduction in off-system sales revenue; summer load was 9% higher than in the prior period.
36th AP: December 2024-May 2025	$104,685,822	$113,784,769	$9,098,947	99.66773%	$8,615,278	$453,436	Purchased-power expense increased $10.9 million, with average natural-gas prices 55% higher than in the prior period. Fuel costs also increased $2.9 million, partly offset by a $10.0 million increase in off-system sales revenue.
37th AP: June-November 2025	$107,367,013	$141,189,996	$33,822,983	99.81231%	$32,071,526	$1,687,975	Higher summer load requirements contributed to higher costs. Relative to the prior period, purchased-power expense increased $21.3 million, fuel costs increased $3.9 million, and off-system sales revenue declined $2.0 million.
38th AP: December 2025-May 2026	$101,376,849	$151,860,050	$50,483,201	99.81136%	$47,868,571	$2,519,398	Fuel costs increased $12.4 million relative to the prior period, partly offset by $1.3 million of higher off-system sales revenue. Additional drivers included Winter Storm Fern and March 2026 purchased-power accruals of $6.5 million for interconnection updates and $4.2 million associated with SPP disputes.

CHANGES IN RISK PROFILE SINCE FAC WAS ESTABLISHED IN 2007

Since the FAC was first approved, EMW's operating environment has become more dependent on organized regional markets. SPP centralized dispatch, market pricing, congestion, and regional transmission planning now influence a larger share of the costs that flow through the FAC. These changes affect the extent to which individual FAC variances are associated with utility procurement, resource planning, and operating decisions.

Extraordinary weather events have demonstrated that FAC costs can change rapidly in response to regional fuel and market conditions. Under a sharing mechanism, these changes may produce customer and shareholder impacts even when the underlying costs arise from broad market conditions. Prudence review remains a separate regulatory safeguard for evaluating the reasonableness of incurred costs.

EMERGING PRESSURES IN MISSOURI

Missouri's FAC framework is operating in an environment that includes increasing large-load interest, regional transmission development, and affordability concerns. These developments affect the analysis of cost causation, allocation of large-load-related costs, and the operation of existing prudence reviews, audits, true-ups, and Commission oversight.

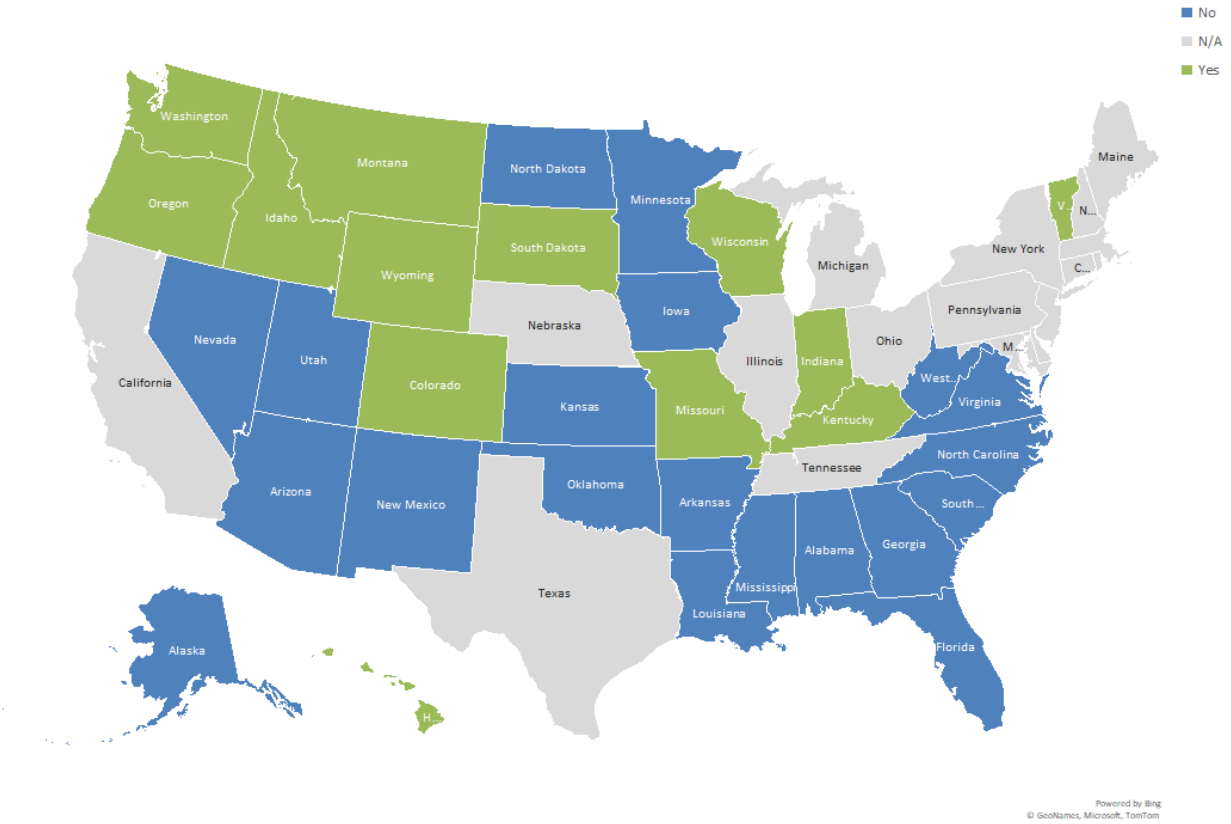
SECTION 3:

FACS ACROSS THE UNITED STATES

FUEL ADJUSTMENT CLAUSES ACROSS THE UNITED STATES

The majority of IOUs in the United States have some mechanism to adjust fuel-related costs. As shown in Figure 1 below, the majority of traditionally regulated states (20 or 61%) fully reconcile fuel and purchased power-related costs and do not have a form of risk sharing between the utility and customers. Additionally, the risk sharing approach is not always implemented consistently within the state.

Figure 1: Fuel-Related Cost/Revenue Sharing in the United States



For the 13 traditionally regulated states that do have a form of risk sharing, there are a variety of sharing methodologies. Appendix A expands on the manner in which the risk is shared between the utility and customers and the nature of the costs or revenues included in the sharing.

In some cases, there is a deadband or earnings test that must be satisfied, but in the majority of cases, the sharing is a straight percentage basis.

Of the 13 states, 7 states (Indiana, Kentucky, Missouri, Montana, South Dakota, Vermont, and Wisconsin) participate in a regional transmission organization (RTO) market such as the Southwest Power Pool (SPP), the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, LLC (PJM), or Independent System Operator-New England (ISO-NE). Three of the states, Indiana, Kentucky, and South Dakota, only share revenues related to Off-System Sales (OSS) or Renewable Energy Credits (RECs). Table 2 below provides a summary of the type of sharing for states that participate in an organized regional market.

Table 2: Fuel-Related Cost/Revenue Sharing by States Participating in an Organized Market

State	Market Participation	Sharing
Indiana	MISO, PJM	OSS margin revenue only
Kentucky	MISO, PJM	OSS margin revenue only
Missouri	MISO, SPP	95/5 for all utilities
Montana	MISO, SPP	90/10 for all utilities
South Dakota	MISO, SPP	OSS margin revenue only
Vermont	ISO-NE	$ efficiency band
Wisconsin	MISO	2% tolerance band

Taken together, the benchmarks show that Missouri applies a fixed shareholder share across a broader set of eligible FAC variances than many of the other jurisdictions reviewed. Other jurisdictions use mechanisms that separately address fuel-cost incentives, market-revenue sharing, transmission recovery, capacity recovery, or large-load cost assignment. These approaches provide points of comparison for assessing how different cost categories are treated relative to the utility's ability to influence the underlying costs.

COSTS INCLUDED IN FUEL AND PURCHASED POWER RECONCILIATION MECHANISMS

In Missouri, the costs eligible for the Fuel and Purchased Power Adjustment (FPA) are the Company's allocated jurisdictional costs for the fuel component of the Company's generating units and reservation charges (FC), purchased power energy charges including applicable Southwest Power Pool charges (PP), emission allowance costs and amortizations offset by the sale of emission allowances (E), cost of transmission of electricity by others associated with purchased power and off-system sales (TC), and the cost associated with the Company's hedging program. These costs are offset by jurisdictional off-system sales revenues and applicable SPP revenues (OSSR) and revenue from the sale of Renewable Energy Certificates or Credits (R). Purchased power demand costs or

revenues associated with purchased power contracts in excess of one year are not included in the reconciliation and are included in base rates.

Across the states reviewed in Appendix A, fuel adjustment and power cost reconciliation mechanisms similarly recover the variable costs of serving retail load, including fuel for utility-owned generation, purchased energy, market purchases, and related hedging or risk-management costs. Many mechanisms also include offsets or credits for off-system sales margins, wholesale sales revenues, renewable energy credits, production tax credits, emission allowance revenues, and other market-related credits. Treatment of capacity, transmission, and environmental compliance costs varies more significantly by jurisdiction. Some states include purchased capacity, transmission or wheeling charges, ancillary services, emissions costs, and renewable compliance costs directly within the fuel or power cost mechanism, while others recover those categories through separate riders or adjustment clauses. Overall, the benchmark shows that FAC-type mechanisms are not limited narrowly to commodity fuel expense; rather, they commonly reconcile a broader set of net power supply costs, with differences across states driven by market structure, resource mix, and the degree to which capacity, transmission, and policy compliance costs are separately tracked.

REGIONAL MARKETS AND FACs

Market structure is one factor considered in the design of FAC sharing provisions. In non-organized markets, vertically integrated utilities generally retain responsibility for dispatch, fuel procurement, bilateral purchases and sales, and other operating decisions. Some jurisdictions use sharing mechanisms in conjunction with these responsibilities to allocate portions of cost or revenue variances between customers and shareholders.

In organized regional transmission markets, centralized dispatch, market pricing, and regional transmission planning determine many short-term operational outcomes. Utilities continue to make decisions regarding long-term resource planning, procurement strategy, hedging, bilateral contracting, and other matters that can affect net power supply costs.

In an RTO or ISO environment, the relationship between a FAC sharing provision and utility management decisions may vary by cost category. Market prices reflect centralized dispatch, congestion, and other regional outcomes, while utility decisions continue to affect resource planning, procurement, hedging, contracting, and operations. The benchmark therefore distinguishes mechanisms that apply sharing broadly from those that limit sharing to specified costs, revenues, bands, or tests.

For comparison purposes, this review groups benchmark states by participation in regional transmission organizations and identifies how each jurisdiction treats cost recovery, prudence review, sharing, deadbands, earnings tests, and other relevant mechanism features.

FUEL AND PURCHASED POWER RISK SHARING INCENTIVES – REGIONAL MARKET PARTICIPATION

Among the benchmark states with regional market participation, risk-sharing provisions vary considerably. Indiana, Kentucky, and South Dakota utilities limit sharing to off-system sales margins or related market revenues, while Missouri and Montana utilities apply broader sharing percentages to fuel and purchased power variances. Vermont and Wisconsin utilities use more targeted approaches that combine reconciliation with deadbands, earnings tests, or periodic resets.

Missouri is one of only two states reviewed that operate in an organized regional market and apply broad fuel and purchased power cost sharing to variances from a base level established in a general rate case. In other RTO jurisdictions, sharing is more commonly limited to market revenues, off-system sales margins, or targeted bands and tests rather than applied uniformly to all eligible fuel and purchased power variances between rate cases.

Indiana, Kentucky, and South Dakota

Indiana, Kentucky, and South Dakota IOUs do not share fuel and purchased power cost variances, but they do return off-system sales margins, renewable energy credit revenues, or other market-related credits to customers. South Dakota also resets the fuel factor, reducing the need for broad variance sharing.

Missouri and Montana

Missouri and Montana IOUs apply broader sharing mechanisms to fuel and purchased power variances. In Missouri, all utilities recover 95% of eligible variances through the FAC, while Montana's major utilities share variances 90/10 between customers and shareholders. In both of these states, the base fuel and purchased power level is established in a general rate case and remains in place until it is reset in a subsequent general rate case.

Vermont and Wisconsin

The utilities in Vermont and Wisconsin rely on more structured reconciliation designs. In Vermont, Green Mountain Power's multi-year rate plan includes a quarterly power supply adjustor (PSA) with an efficiency band for a component of power supply related costs and a performance incentive tied to reductions in power supply costs. In Wisconsin, utilities use an annual fuel cost plan, symmetrical 2% tolerance band, earnings test, deferral treatment, and annual fuel factor reset.

FUEL AND PURCHASED POWER RISK SHARING INCENTIVES – NON-REGIONAL MARKET PARTICIPATION

Utilities in states that do not participate in a regional market can use their assets to make economic dispatch decisions, creating value for customers.

Colorado

Colorado's major IOUs fully reconcile fuel, purchased energy, wheeling, gas price risk-management costs, and renewable standard transfers through Energy Cost Adjustment mechanisms, while sharing positive energy sales net income and certain allowance margins. Commodity, purchased capacity, and ongoing transmission investment are recovered separately through dedicated adjustment mechanisms. Public Service Company of Colorado has proposed large load tariff language to recover incremental generation and transmission-related costs, including fuel and purchased power from the large load class customers.[1]

Hawaii

Hawaiian Electric Company (HECO) operates within a performance-based ratemaking framework and separates fuel and purchased energy recovery from other purchased power costs. HECO's Energy Cost Reconciliation Clause (ECRC) includes fuel, distributed generation, and purchased energy contracts with limited fossil-fuel cost sharing, while the Purchased Power Adjustment Clause (PPAC) recovers capacity, operations and maintenance, and other non-energy purchased power costs. HECO also operates under a rewards-only shared savings mechanism tied to reductions in fuel, purchased energy, capacity, and major project costs.

Idaho

Idaho's major IOUs use utility-specific power cost adjustment mechanisms that reconcile 90% to 95% of eligible net power cost variances, including fuel and purchased power costs net of off-system sales or special contract revenues.

Oregon

Oregon's major utilities rely on annual power cost update and variance mechanisms, including deadbands, sharing percentages, earnings tests, and limits on deferred cost recovery. These mechanisms are designed to reconcile net variable power cost deviations while limiting customer and utility exposure to forecast error.

Washington

Washington's major IOUs use graduated sharing structures with deadbands and tiered customer/shareholder allocations. These mechanisms reconcile variations from baseline power costs and typically treat resulting balances as deferrals that are later surcharged or refunded once threshold levels are reached.

[1] Proceeding No. 23AL-0137E In the Matter of Advice Letter No. 2018 – Electric filed by Public Service Company of Colorado to Revise Colorado P.U.C. No. 8 – Electric Tariff to Address Large Loads, Add a New Schedule Transmission Large Service (Schedule TL) Rate, Add a New Clean Transition Tariff (Schedule CTT), and Implement Changes to the Transmission Line Extension Policy, to Become Effective May 3, 2026.

Wyoming

Wyoming applies differentiated sharing percentages by cost category and utility. Montana-Dakota Utilities shares fuel-related variances 85/15 and purchased power-related variances 95/5, while Rocky Mountain Power's energy cost adjustment applies 80/20 sharing to eligible net power cost variances.

TRANSMISSION COSTS

A Regional Transmission Organization (RTO), such as SPP, is responsible for independently coordinating non-discriminatory access to transmission services. Transmission service is taken through the Open Access Transmission Tariff (OATT) and EMW is considered a Transmission Customer.

Transmission service provides the delivery of electric energy over high-voltage transmission lines and facilities to local distribution facilities for the purpose of providing energy for end-user consumption. Transmission service and Network Integration Transmission Service (NITS) allow for a more efficient pooling of resources that lowers costs and improves reliability.[2] This is accomplished because EMW can optimize its load serving efficiency by utilizing a market geared toward maximizing economic commitment and dispatch efficiency. Rather than each market participant determining which resources need to generate to serve load cost-effectively, EMW's customers share in the benefits of all SPP members by allowing for a regional solution to serve load to maximize cost-effectiveness. The transmission infrastructure in the SPP footprint enables this construct and creates immediate benefits for members.

Transmission costs are allocated to EMW through Schedule 9 (Network Integration Transmission Service), Schedule 10 (Wholesale Distribution Service), and Schedule 11 (Base Plan Zonal Charge and Region Wide Charge), included in base fuel and purchased power costs and reconciled through the Fuel Adjustment Clause. Schedule 1-A (Tariff Administrative Fee) and Schedule 12 (FERC Assessment Charge) are currently considered FAC-ineligible and excluded from any true-up outside of a general rate case.

Transmission costs differ across the benchmark states in source, allocation method, and recovery treatment. For utilities participating in RTOs or other organized markets, regional transmission charges are established through regional tariffs and allocation processes. The benchmark identifies whether these costs are included in fuel or power cost mechanisms, recovered through separate riders, or reflected in base rates.

[2] SPP OATT Section 30.5. "As a condition of receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2 and in accordance with the Energy and Operating Reserve Markets procedures in Attachment AE."

The benchmark shows that some jurisdictions include transmission, wheeling, or ancillary-service costs in fuel or power cost mechanisms, while others use separate transmission riders or base-rate treatment. Separate recovery appears in jurisdictions where transmission investment and regional charges are tracked outside the fuel mechanism. For EMW, SPP transmission charges can be compared with short-term fuel procurement and dispatch costs based on cost drivers, timing, allocation, and the extent of utility decision-making associated with each category.

Table 3 below describes cost recovery for transmission costs for the 7 states previously identified that operate in regional markets and have some form of risk sharing.

Table 3: Transmission-Related Cost Recovery Treatment for States with Risk Sharing That Participate in an Organized Market

State	Transmission Cost Recovery Treatment
Indiana	Major IOUs have separate rider for MISO/PJM transmission costs, fully reconciled.
Kentucky	Major IOUs recover PJM costs through the fuel adjustment clause, fully reconciled.
Missouri	All Missouri utilities include certain transmission-related costs in base fuel costs and recover 95% of variances through the Fuel Adjustment Clause.
Montana	NorthWestern's Power Cost and Credits Adjustment Mechanism (PCCAM) includes transmission costs; Montana-Dakota Utilities has a fuel tracker that excludes transmission and uses separate recovery mechanisms in other jurisdictions.
South Dakota	NorthWestern includes some transmission-related energy charges in the fuel tracker; Black Hills, MidAmerican and Montana-Dakota Utilities have separate transmission riders. Costs are fully reconciled.
Vermont	ISO-NE transmission costs are included in quarterly power supply adjustor established as part of the multi-year rate plan, Component B, recovering costs that fall outside of an efficiency band.
Wisconsin	MISO transmission-related costs are reflected within annual fuel cost planning and reconciliation and are subject to the 2% tolerance band.

CAPACITY COSTS

Across the benchmark states, capacity costs are recovered through fuel or power cost mechanisms, purchased power or capacity riders, resource adequacy mechanisms, or base rates, depending on the

jurisdiction and market structure. Treatment also varies according to whether the cost relates to short-term purchased power, longer-term resource adequacy obligations, generation investment, market capacity requirements, or large-load growth. Table 4 identifies benchmark jurisdictions with capacity-specific recovery mechanisms.

Table 4: Capacity-Related Cost Recovery Treatment

State	Capacity-specific Cost Recovery Treatment
Indiana	AES Indiana uses a dedicated Capacity Adjustment (CAP) Rider that separately reconciles capacity auction purchases, bilateral capacity transactions, and other capacity-related costs/revenues.
Oklahoma	Oklahoma Gas & Electric (OG&E) Generation Capacity Rider (GCR) recovers the revenue requirement associated with new gas-fired generation capacity projects before those costs are rolled into base rates.
Colorado	Reliability or capacity costs recovered through separate riders rather than through traditional FAC mechanisms. Colorado does not participate in an organized regional wholesale market.

OFF-SYSTEM SALES / RENEWABLE ENERGY CREDITS REVENUE SHARING

Across the benchmark states, off-system sales margins, REC revenues, emission allowance proceeds, production tax credits, and similar credits are commonly used to offset fuel and purchased power costs. Allocation methods vary: some jurisdictions return these amounts in full, while others use partial or graduated sharing. Indiana, Kentucky, and South Dakota limit sharing primarily to off-system sales, REC, or related market revenues rather than broadly applying sharing to fuel-cost variances.

SECTION 4:

FUEL COST REBASING

ESTABLISHING BASE FUEL COSTS FRAMEWORK

Fuel cost recovery design involves two separate questions: how the prospective fuel-related cost level used to set customer charges is established, and how differences between that level and actual costs are reconciled. A fuel adjustment mechanism can retain a fuel component in base rates while updating the total effective fuel charge through a separate rider. Alternatively, the prospective fuel cost allowance can be refreshed independently of a general rate case through a separate fuel cost rider.

Missouri defines base energy costs as eligible fuel and purchased power costs, net of fuel-related revenues, included in the revenue requirement used to set base rates in a general rate case. That base energy cost remains in place until the next rate case. Periodic FAC adjustments include the cost variance, the Commission-approved incentive allocation, true-up amounts, prudence adjustments, and interest. The FAC true-up reconciles amounts authorized for recovery with amounts actually recovered; it does not replace the baseline with a new forward-looking fuel cost forecast. This distinction is important when evaluating alternatives that update expected costs regularly rather than repeatedly measuring actual costs against an older baseline established in a rate case.

The majority of vertically integrated states either use forward-looking estimates of fuel and purchased power costs or update the fuel rate to forecast or current costs between rate cases. Missouri is in the minority with three other states (Montana, Utah, and Wyoming) where actual fuel costs are reconciled against a fixed base set in a general rate case. The remaining states update the fuel rate customers pay between rate cases based on either current or forecasted costs. Several states have a separate fuel cost proceeding where the entirety of fuel costs are recovered outside of base rates. Tables 5 and 6 summarize how jurisdictions with risk sharing mechanisms establish and rebase fuel and purchased power costs.

Table 5: Base Fuel Cost Establishment and Reconciliation Frameworks for States with Risk Sharing That Participate in an Organized Market

State	Base Fuel Cost Establishment Approach
Indiana	A fuel-cost allowance is included in the general rate case. Subsequent FAC proceedings use updated forecasts to calculate the adjustment above or below that allowance.
Kentucky	A baseline fuel cost is established in base rates with monthly FAC adjustments using actual fuel costs. The Commission conducts a formal review every two years and resets the baseline when necessary through that fuel review.
Missouri	Base fuel and purchased power costs established in a general rate case. The FAC reconciles actual costs and recoveries against the approved baseline.
Montana	Base fuel costs are established in a general rate case. The fuel cost adjustment mechanism reconciles actual and allowed fuel costs, subject to sharing.
South Dakota	The practice varies by utility. Xcel Energy and MDU recover fuel costs through a fuel clause established using either a forecast or 4 months of actuals with a reconciliation process. Black Hills and NorthWestern establish base fuel costs in a general rate case and reconcile through an adjustment clause.

Vermont	Green Mountain Power operates under a multi-year rate plan. Power supply costs and retail revenues are forecast and refreshed annually through base rate filings under its multi-year regulation plan.
Wisconsin	Annual forecasted fuel cost plan, subject to subsequent reconciliation. Refunds are subject to a symmetrical 2% tolerance band, and recovery of excess costs is also subject to the excess revenues test.

Table 6: Base Fuel Cost Establishment and Reconciliation Frameworks for States with Risk Sharing That Do Not Participate in an Organized Market

State	**Base Fuel Cost Establishment Approach**
Colorado	Base fuel costs are established outside of base rates through the Electric Commodity Adjustment (ECA) clause. Quarterly ECA filings and an annual reconciliation filing reset the base fuel costs.
Hawaii	Operates under a multi-year performance-based ratemaking framework. Fuel and purchased power costs recovered through the Energy Cost Recovery Clause (ECRC) and Purchased Power Adjustment Clause (PPAC) with heat-rate parameters set in the general rate case. Fuel costs are reconciled on a monthly basis.
Idaho	Base fuel costs are established and reset through the general rate case process. The annual Power Cost Adjustment (PCA) / Energy Cost Adjustment (ECA) clauses reconcile the difference. Idaho Power's fuel costs are reset annually to a projected power cost.
Oregon	Portland General Electric (PGE) projects net variable power costs for the following year. The process includes an initial forecast, regulatory review, and a subsequent update to the forecast incorporating any directives from the Commission. Separately, actual annual net variable power costs are compared with the projected net variable power costs with a portion of the variance recognized in rates, subject to deadbands, sharing, and an earnings test.
Washington	Base fuel costs are established during a power cost proceeding.
Wyoming	Base fuel costs are established during a general rate case. The annual fuel cost reconciliation mechanisms reconcile the difference.

Table 7 below summarizes how other neighboring vertically integrated jurisdictions rebase fuel and purchased power costs.

Table 7: Base Fuel Cost Establishment and Reconciliation Frameworks for Select Neighboring States

State	Base Fuel Cost Establishment Approach
Arkansas	Entergy Arkansas operates under a formula rate plan. The Energy Cost Recovery Rider (ECR) recovers net fuel and purchased energy costs, is initially determined in a general rate case proceeding, and redetermined through annual filings. Arkansas participates in a regional market and does not have a risk sharing mechanism for fuel costs.
Iowa	Fuel costs recovered through the Energy Adjustment Clause (EAC) rider calculated based on a forecast of energy costs. Iowa participates in a regional market and does not have a risk sharing mechanism for fuel costs.
Kansas	Fuel costs recovered through the Energy Cost Adjustment (ECA) rider based on forecasted fuel costs net of revenues. Kansas participates in a regional market and does not have a risk sharing mechanism for fuel costs.
Oklahoma	Fuel costs recovered through the Fuel Cost Adjustment (FCA) rider based on forecasted costs. Factors are updated and reviewed semi-annually with an annual prudence review. Oklahoma participates in a regional market and does not have a risk sharing mechanism for fuel costs.

SECTION 5:

LARGE LOADS AND FUEL ADJUSTMENT CLAUSES

LARGE LOADS

Large-load growth, including data centers and high-load-factor industrial customers, can increase fuel, purchased power, capacity, transmission, and resource-procurement requirements before those costs are reflected in base rates. Jurisdictions reviewed in this report have addressed these effects through customer-specific tariff provisions, long-term electric service agreements, minimum billing demands, collateral or credit support, ramp schedules, exit or capacity-reduction fees, and assignment of incremental capacity, generation, transmission, and interconnection costs. These provisions may operate separately from, or in conjunction with, traditional FAC mechanisms. The following recent case examples describe how selected jurisdictions identify, track, and recover large-load-related fuel and purchased power costs.

LARGE LOAD TARIFF CASE EXAMPLES

Colorado

Public Service Company of Colorado's proposed Schedule TL would apply to new or expanded transmission-voltage customers with forecast demand of 50 MW or more. The tariff creates a separate Large Load customer class and applies an incremental cost test so that Large Load customers pay the greater of standard embedded-cost rates or the incremental generation and transmission costs required to serve them. For generation, PSCo would compare the incremental generation portfolio cost—including utility-owned resource revenue requirements, PPA capacity costs, production and investment tax credits, and incremental fuel and purchased energy impacts estimated through production cost modeling—to all generation-related revenues paid by Schedule TL customers, including revenues from base demand and energy rates. If incremental costs exceed those revenues, PSCo would impose a Schedule TL surcharge; if standard revenues exceed incremental costs, the resulting margin benefits other customers. The proposal therefore insulates existing customers by assigning large load-driven fuel, purchased power, capacity, and generation costs to the Large Load class rather than allowing shortfalls to be socialized broadly. PSCo also proposes to conduct this generation incremental cost test whenever relevant costs are added to base rates or riders, including the ECA, PCCA, or GRSA, and any required surcharge revenues would be credited to other customer classes to reduce their generation cost allocation. Transmission costs are treated similarly: customer interconnection facilities are directly assigned upfront, while network reinforcement costs are tested against Schedule TL transmission revenues; any shortfall is recovered from Schedule TL customers and credited to other classes. The tariff also includes an 80% Contract Demand minimum bill and exit fee structure, offering additional protection if a large load does not materialize, reduces load, or exits before the end of its service term. The structure does not include broad fuel-cost risk sharing for existi

ng customers; instead, sharing is effectively limited to the direction of benefits or shortfalls through the incremental cost test. Schedule TL absorbs incremental-cost deficiencies, while revenues above incremental cost create benefits for other customers.[3]

The proposed tariff also requires customers to provide a five-year load forecast of expected monthly on-peak and off-peak demand and energy, along with at least semi-annual updates. Inaccuracies do not constitute a breach of the ESA, but customers are expected to prepare the load forecasts in good faith and to notify the utility of material changes.

[3] Proceeding No. 23AL-0137E In the Matter of Advice Letter No. 2018 – Electric filed by Public Service Company of Colorado to Revise Colorado P.U.C. No. 8 – Electric Tariff to Address Large Loads, Add a New Schedule Transmission Large Service (Schedule TL) Rate, Add a New Clean Transition Tariff (Schedule CTT), and Implement Changes to the Transmission Line Extension Policy, to Become Effective May 3, 2026.

Wisconsin

Wisconsin Electric Power Company's Very Large Customer (VLC) tariff is mandatory for very large energy users and requires that VLC customers subscribe to specific resources under the proposed Bespoke Resources tariff. The Bespoke Resources tariff requires any customer taking service under the VLC tariff to enter into long-term agreements to subscribe to energy and capacity resources to reduce long-term reliance on purchasing power through wholesale markets. Bespoke Resources may include facilities such as new generators, storage facilities, or other resources, in order to meet the large demand being added to the system by VLCs. The tariffs and service agreements are intended to meet the significant energy and capacity needs of VLCs while ensuring the VLCs pay for the infrastructure investments needed to serve them and avoid cross-subsidization by other customers. The VLC and Bespoke Resources tariffs and service agreements include long-term contractual commitments and additional financial protections not present in the other tariffs.[4]

In approving the tariff, PSC Commissioner Hawkins stated in the Commission's press release, "I'd also like to acknowledge the attention the issue of transmission costs has gotten from intervenors and the public. Without the large and loud engagement on this topic, I doubt we would have seen the movement we have from the applicant and ATC to evaluate creative solutions to this issue."[5]

Oklahoma

In response to Oklahoma House Bill 2992 and the Oklahoma Corporation Commission's directive to establish a large-load tariff, Oklahoma Gas & Electric proposed a new Extra Large Power and Light tariff applicable to new or expanded customers that meet the tariff's extra-large load thresholds. For fuel and purchased power costs, the proposal excludes XLPL customers' energy-related costs from the standard Fuel Cost Adjustment recovery and instead charges those customers the hourly Southwest Power Pool Day-Ahead Locational Marginal Price for OG&E, adjusted for line losses, on actual energy usage. XLPL customers remain responsible for their allocated share of capacity and purchased power agreement costs recovered through the FCA, and those costs are subject to the tariff's minimum Billing Energy requirements. The associated terms and conditions also provide that any potential adverse rate impact on other customer classes—including impacts from added generation, power delivery infrastructure, fuel, purchased capacity expense, or purchased power expense—will be reviewed and addressed in each general rate case and each FCA annual review. If such review shows an adverse impact, OG&E's Customer Class Protection Charge, initially set at $0/kW-month, provides a tariff-embedded mechanism to collect the shortfall from XLPL customers

[4] Docket 6630-TE-113, Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs, Order issued May 21, 2026.
https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=591873 ; Rate Schedule Very Larg Customer – Market Pricing Tariff

[5] PSC Overhauls We Energies' Data Center Tariff, Makes Improvements to Protect Existing Customer, Press Release issued April 24, 2026.

and credit revenues back to other customer classes. The tariff further protects existing customers through 85% minimum Billing Demand, 90% minimum Billing Energy, a 15-year minimum term following a load ramp period, CIAC responsibility for transmission and distribution infrastructure, collateral equal to 60 months of minimum charges, and termination or capacity-reduction fees. The proposal therefore does not rely on broad sharing of XLPL-driven fuel or purchased power cost exposure with existing customers; rather, it removes XLPL energy from standard FCA treatment, requires XLPL customers to pay market-based energy costs plus allocated capacity/PPA costs, and preserves Commission review and a class-protection charge as a fail-safe against cross-subsidization.[6]

Utah

Rocky Mountain Power's (RMP) Large Load Service Contract (LLSC), approved by the Utah Public Service Commission in Docket No. 26-035-05 in April 2026, uses a customer-specific contract and accounting framework to isolate large-load costs from general retail recovery. Under the LLSC, the customer pays a fixed cost component (Reservation Charges), a variable cost component (Energy Charges), and applicable surcharges, riders, and taxes. RMP removes Reservation Charge revenues from revenue requirement and net power costs (NPC), and excludes the costs of customer load facilities, bridging market capacity purchases, incremental generation resources, and RMP's associated return from general customer recovery. RMP represented that Energy Charges also allow existing resources to be economically dispatched to serve the customer's load and that, in total, the LLSC is expected to provide net benefits to other retail customers.[7]

RMP states its other customers will not bear incremental costs of the LLSC; rather, they are expected to benefit from it in several ways. First, RMP contends other customers will benefit from the economic re-dispatch of the system. Second, other customers will benefit from the Customer's contributions to applicable surcharges and riders. Third, Utah residents and the state will benefit from state and local tax revenue through the contract term. RMP asserts other customers are properly shielded from any costs and risks associated with the LLSC. For example, in addition to the Reservation and Energy Charges, the Customer will reimburse RMP for all incremental costs of serving the Customer's load, which the LLSC lists categorically.[8]

[6] Case No. PUD2026-000046, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Approving its New Extra Large Load Tariff and Terms and Conditions of Service for Extra Large Load Customers and a Regulatory Asset to Recover Costs Associated with Portfolio Optimization Software.

[7] Docket No. 26-035-05 Application of Rocky Mountain Power for Approval of a Large-Load Service Contract between PacifiCorp and a Large-Load Customer, Order issued April 10, 2026. https://pscdocs.utah.gov/electric/26docs/2603505/344733260350 5oasadmfatmdrao4-10-2026.pdf

[8] Incremental Costs include incremental energy costs used by the Customer facilities, incremental interconnection costs used by the Customer facilities, and incremental capacity-related costs, including

costs for offsetting peak demand, ancillary services, supplying reserves, resource adequacy, and resource sufficiency.

APPENDIX A:

FUEL AND PURCHASED POWER ADJUSTMENT MECHANISM RISK SHARING

FUEL AND PURCHASED POWER ADJUSTMENT MECHANISM RISK SHARING BY STATE

Table 8: Fuel-Related Cost/Revenue Risk Sharing in the United States

State	Risk Sharing	Regional Market Participation
Colorado	• Black Hills: Effective through 2027, the Energy Cost Adjustment (ECA) fully reconciles the cost of fuel, purchased power energy (excluding demand) charges, transmission of electricity by others, gas price volatility risk management, and Net Renewable Energy Standard Adjustment (RESA) transfers. 90% sharing of positive Energy Sales Net Income (OSS margin).[9] • Public Service Co of Colorado (Xcel): Electric Commodity Adjustment (ECA) full cost reconciliation of fuel, purchased energy and wheeling (excluding demand), gas price volatility risk management, and Net Renewable Energy Standard Adjustment (RESA) transfers. 90% sharing of positive Energy Sales Net Income (OSS margin). 90% sharing of positive short-term sales margins in excess of a threshold value and sharing of SO_2 allowance margins in accordance with Commission orders.[10] • ECA cost forecasted on a 12-month rolling basis with a quarterly adjustment. • Both companies have separate capacity and transmission recovery mechanisms. • Purchased Capacity Cost Adjustment (PCCA) fully recovers the incremental cost of capacity-related charges from entities providing contractual power supplies that are not included in base rates. • Transmission Cost Adjustment (TCA) reflects the ongoing capital costs associated with transmission investment that are not being recovered through the Company's base rates. • PSCo proposed a new base rate schedule for Large Load customers. Schedule TL Tariff proposes language to recover incremental fuel and generation-related costs from the large-load customers.[11]	None
Hawaii	• Hawaiian Electric Company: Energy Cost Recovery Clause (ECRC) includes fuel contracts, distributed generation	None

[9] Black Hills Colorado Electric, LLC d/b/a Black Hills Energy Tariff No. 11, Energy Cost Adjustment (ECA), Purchase Capacity Cost Adjustment (PCCA), Transmission Cost Adjustment (TCA.

[10] Public Service Company of Colorado Tariff No. 8, Electric Commodity Adjustment (ECA), Purchase Capacity Cost Adjustment (PCCA), Transmission Cost Adjustment (TCA).

[11] Proceeding No. 26AL-0137E, In the Matter of Advice No. 2018 – Electric Filed by Public Service Company of Colorado to Revise Colorado P.U.C. NO. 8 – Electric Tariff to Address Large Loads and Add Transmission Large (Schedule TL) and Clean Transition Tariff (Schedule CTT) and Implement Changes to the Transmission Line Extension Policy, Direct Testimony of Jeffrey Knighten, April 2, 2026.

State	Risk Sharing	Regional Market Participation
	contracts, and purchased energy contracts and shares 2% of *fossil fuel-only* costs symmetrically. Sharing is capped at +/- $2.5 million for Oahu, and lesser amounts for HECO's smaller island service territories. Purchased Power Adjustment Clause (PPAC) includes capacity costs, operations and maintenance costs, and other non-energy costs, including costs incurred by the Company to operate and maintain generation units owned by others for the purpose of providing power to the utility system.[12] • Operates under a Performance-Based Ratemaking framework with a rewards-only Collective Shared Savings Mechanism (CSSM) performance incentive of 20% tied to reductions in fuel, purchased energy and capacity, and major projects.[13]	
Idaho	• Avista: Temporary Power Cost Adjustment (PCA) recovers or rebates a portion of the difference between actual and allowed net power supply costs (hydroelectric generation, secondary prices, thermal fuel costs, and changes in revenues and expenses from energy and capacity contracts, transmission expenses, and other offsetting revenues). 90% of the change in power expense is recovered from customers.[14] • Idaho Power: Power Cost Adjustment (PCA) recovers or rebates 95% of the variance between fuel and purchased power expenses (excluding cogen and small power producers) less off-system surplus sales (OSS) revenue and special contract revenue.[15] • PacifiCorp/Rocky Mountain Power: Energy Cost Adjustment (ECA) tracks difference between actual and base net power costs, excluding PTC, and REC revenue, recovering or refunding 90% of the variance. PTC and REC revenue variances are fully shared. Base rates are established in a general rate case.[16] • No specific tariff provisions addressing direct assignment or "no-PCA" participation treatment for very large load customers under special contracts; however, revenue from market-based special-contract pricing is excluded from Idaho Power's PCA.	Western Energy Imbalance Market (EIM)
Indiana	• Duke Energy Indiana: Fuel Cost Adjustment plus separate environmental, RTO non-fuel, reliability, federally mandated, renewable-project and generation-cost trackers. GCT 2 was	MISO, PJM

[12] Hawaiian Electric Company, Energy Cost Recovery Clause, Effective October 1, 2023 and Purchased Power Adjustment Clause, Effective June 1, 2026.
[13] Hawaiian Electric Company, Performance Incentive Mechanism Provision / Collective Shared Savings Mechanism, Effective January 1, 2023.
[14] Avista Corporation d/b/a Avista Utilities, Temporary Power Cost Adjustment – Idaho, Effective October 1, 2025. Case No. AVU-E-26-05, In the Matter of the Power Cost Adjustment (PCA) Annual Rate Adjustment Filing of Avista Corporation.
[15] Idaho Power Company, Power Cost Adjustment, Effective June 1, 2026; Case No. IPC-E-26-10, In the Matter of Idaho Power Company's Application for Authority to Implement Power Cost Adjustment (PCA) Rates for Electric Service from June 1, 2026 through May 31, 2027, Order No. 37054 issued May 29, 2026.
[16] Rocky Mountain Power, Energy Cost Adjustment, Effective June 1, 2026; Case No. PAC-E-26-05, In the Matter of Rocky Mountain Power Requesting Approval to Recover $4.1 Million Associated with the ECAM Deferral and Refund $1.4 Million Associated with the RRA.

State	Risk Sharing	Regional Market Participation
	approved September 9, 2026 for October 2026-March 2027, with semiannual forecast/actual reconciliation and continuing project oversight. • AES: Fuel Cost Adjustment plus separate capacity, OSS, RTO, and environmental riders, with the statutory NOI test. • Indiana & Michigan Power: FAC uses a six-month fuel-cost forecast and reconciles at least six months of actual results. Separate ECR, OSS/PJM, RAR and SPR riders address environmental costs, wholesale-margin sharing/PJM costs, purchased-power capacity, and solar investment.	
Kentucky	• Duke Energy Kentucky: Profit Sharing Mechanism (PSM) Rider that shares 90% of off-system power sales margins, PJM capacity proceeds, surplus gas sales, and REC proceeds.[17] • Louisville Gas & Electric Co: Fuel Adjustment Clause (FAC) fully recovers fuel and net energy purchases, exclusive of capacity or demand charges. Off-System Sales Adjustment Clause (OSS) recovers 75% of net Off-System Sales margin.[18] • Kentucky Power: Fuel Adjustment Clause (FAC) – fully recovers fuel and net energy purchases, exclusive of capacity or demand charges. Purchased Power Adjustment (PPA) – fully recovers purchased energy and capacity variances from the level included in base rates. Environmental Surcharge (ES) – fully recovers variance in environmental compliance costs. System Sales Clause (SSC) – fully recovers variances in system sales.[19]	PJM
Missouri	• Liberty Utilities Empire District Electric Co. (EDE), Evergy Metro Inc. (EMM), Evergy Missouri West Inc. (EMW), and Ameren Union Electric Co. (UE) have Fuel Adjustment Clauses (FAC) in place that recover 95% of variances in fuel and purchased power costs, net emissions allowance costs, and OSS revenues.[20] • Evergy Missouri West Inc. (EMW) – Costs include fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool (SPP) charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales, and the cost described below associated with the company's hedging program all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, revenue from the sale of Renewable Energy Certificates or Credits (REC). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year or costs	MISO, SPP

[17] Duke Energy Kentucky, Profit Sharing Mechanism (PSM) Rider, Effective June 1, 2026.
[18] Louisville Gas and Electric Company and Kentucky Utilities Company, Fuel Adjustment Clause and Off-System Sales Adjustment Clause, Effective February 16, 2026.
[19] Kentucky Power Company, Fuel Adjustment Clause (FAC), Purchased Power Adjustment (PPA), Environmental Surcharge (ES), and System Sales Clause (SSC), effective March 1, 2026.
[20] Evergy Missouri West, Inc. d/b/a/ Evergy Missouri West, Fuel Adjustment Clause Rider FAC, Effective January 1, 2025.

State	Risk Sharing	Regional Market Participation
	associated with service provided to customers taking energy through Schedule MKT. • Evergy Missouri West and UE have a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) that fully recovers or refunds costs or benefits received as a result of compliance with the state's renewable energy standards, capped at 1% annually for recovery and no limit to the credit.	
Montana	• Montana-Dakota Utilities: The Fuel and Purchased Power Cost Tracking Adjustment (FPPC) recovers or refunds 90% of the variance above or below the established base revenues of fuel and power purchased, wholesale sales revenues and Renewable Energy Credit revenues. Contract Service Rate 35 is excluded.[21] • NorthWestern Energy: Power Cost and Credits Adjustment Mechanism (PCCAM) allows for surcharge or refund of 90% of the variance between base and actual fuel, purchased power and capacity costs, transmission less sales revenue, production tax credits, contract sales, and other revenue credits.[22]	MISO, SPP
Oregon	• Portland General Electric[23]: ○ Annual Power Cost Update – changes the projected net variable power costs (NVPC) for net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options, and other financial instruments incurred to serve retail load. ○ Annual Power Cost Variance Mechanism (Schedule 126) – subject to the Earnings Test of +/- 100 basis points ROE, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband ($30.0 million) for a Positive Annual Variance or the Negative Annual Power Cost Deadband ($15.0 million) for a Negative Annual Variance. ○ Renewable Resources Automatic Adjustment Clause – recovers the revenue requirements of a qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates. ○ Data Center Standard Service (Schedule 96) – new tariff that shifts generation, transmission, and distribution capital costs to developers, mitigates ratepayer risk through stringent demand charges and links data center growth to the state's clean energy goals.	None

[21] Montana-Dakota Utilities Co. Fuel and Purchase Power Cost Tracking Adjustment Rate 58, Effective July 21, 2026.
[22] NorthWestern Energy, Annual Power Costs and Credits Adjustment Mechanism EPCC-1, Effective October 30, 2023.
[23] Portland General Electric Company, Annual Power Cost Update, Annual Power Cost Variance Mechanism, Renewable Resources Automatic Adjustment Clause, Effective July 8, 2026.

State	Risk Sharing	Regional Market Participation

	• Idaho Power[24]:
	  ○ Power Cost Adjustment Mechanism (Schedule 56) - subject to the Earnings Test of +/- 100 basis points ROE, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband (250 basis points of ROE $ equivalent) for a Positive Annual Variance or the Negative Annual Power Cost Deadband (125 basis points of ROE $ equivalent) for a Negative Annual Variance.
	• Pacific Power[25]:
	  ○ Power Cost Adjustment Mechanism (PCAM)
	  ○ Deadband - If the power cost variation falls within this deadband, there will be no power cost rate adjustment. To ensure the PCAM is revenue neutral, the mechanism uses an asymmetric deadband, with a negative annual power cost variance deadband of $15 million, and a positive annual power cost variance deadband of $30 million.
	  ○ Sharing mechanism - For any power cost variance above or below the deadband, customers will bear 90 percent of the adjustment and Pacific Power will bear 10 percent of the adjustment.
	  ○ Earnings Test - +/- 100 basis points around Pacific Power's allowed ROE. If Pacific Power is earning within this range of its authorized ROE, there will be no power cost adjustment for that year.
	  ○ Amortization Cap - Limit amortization of deferred amounts under the PCAM in any one year to 6 percent of Pacific Power's revenues for the preceding calendar year.
	• Oregon is also actively addressing data-center-specific customer classes.
	• Renewable resource adjustment clauses (RACs) are utilized for the state's electric utilities for the recovery of prudently incurred costs associated with meeting the state's renewable energy standards. The mechanism allows for cost recovery, without filing a general rate case, of renewable resources that are expected to be placed into service in the current year.	

South Dakota	• NorthWestern: Adjustment Clause fully recovers from or refunds to customers the variance in delivered cost of energy (in accordance with wholesale transmission rates) and delivered cost of fuel (includes fuel, purchased power, REC revenue, Production Tax Credits, excludes long-term capacity costs).[26]	MISO, SPP, WEIS

[24] Idaho Power Company, Annual Power Cost Update, Annual Power Cost Variance Mechanism, Renewable Resources Automatic Adjustment Clause, Effective October 15, 2025.
[25] Docket No. UE 246, In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision, Order No. 12-493, issued December 20, 2012; Pacific Power Power Cost Adjustment Mechanism, Effective May 1, 2026.
[26] NorthWestern Energy Public Service Corporation d/b/a NorthWestern Energy tariff, Adjustment Clause, Effective December 29, 2015. https://northwesternenergy.com/docs/default-source/default-document-library/billing-and-payment/rates-and-tariffs/south-dakota/tariff-electric-complete.pdf

State	Risk Sharing	Regional Market Participation
	• Northern States Power (NSP): 100% of asset based intersystem sales margins (defined as intersystem sales revenues less the sum of fuel, energy costs (including costs associated with MISO markets that are recorded in FERC Account 555), and any additional transmission costs incurred that are required to make such sales) are allocated to customers. 30% of non-asset based margins are allocated to customers. 90% of revenue generated by the sale of RECs credited to customers. Revenue generated by the sale of emission allowances are fully credited to customers. Capacity Sale Gains in the Planning Resource Auction conducted by the MISO are fully credited to customers. Nuclear production tax credits (PTC) established by the Inflation Reduction Act and earned by the utility are fully credited to customers through the Infrastructure rider. Incremental property tax above the amount included in base rates will flow through the fuel clause. Incremental annual revenue requirement associated with transmission projects recovered through Transmission Cost Recovery rider.[27] • Black Hills Power (BHP): Fuel and Purchased Power Adjustment (FPPA) fully recovers variance between base and actual fuel and purchased power costs; 90% of revenue generated by the sale of Renewable Energy Credits credited to customers; 70% of power marketing income (revenue from wholesale power and emission allowances sales, less certain expenses related to the operation of the wholesale business) credited to customers. Transmission Cost Adjustment (TCA) fully recovers variances between actual and base year transmission costs (Network Integrated Transmission Service, all Point-to-Point Transmission Service, including all associated ancillary service charges, and regulation expenses, required to support the Company's system energy sales).[28]	
Vermont	• Green Mountain Power: Power Supply and Retail Revenue Adjustor (PSRRA) - Component A: Regional Capacity and Transmission Charges - full reconciliation between forecasted and actual costs on a quarterly basis. Component B: Purchase, Generation, and Sale of Energy, along with Renewable Energy Credit Revenues and Renewable Energy Standard compliance expenses - GMP retains the first $175,000 of favorable quarterly Component B variances and absorbs the first $350,000 of unfavorable quarterly Component B variances. [29]	ISO-NE

[27] Northern States Power Company tariff, Fuel Clause Rider, Infrastructure Rider, Transmission Cost Recovery Rider, effective July 1, 2026.
https://puc.sd.gov/commission/Tariffs/Electric/Xcel/FuelAdjustment/2026/0926.pdf
[28] Black Hills Energy tariff, Fuel and Purchase Power Adjustment, effective May 1, 2024. https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/bhp-sd-rates_2.pdf
[29] Case No. 25-1955-PET, Petition of Green Mountain Power Corporation for approval of its new Multi-Year Regulation Plan pursuant to 30 V.S.A. Sections 108, 209, 218, and 218d and Case No. 26-0096-TF Tariff filing of Green Mountain Power Corporation for a 7.5% rate increase effective with bills rendered on or after October 1, 2026, Order at 26-27, issued August 28, 2026.

State	Risk Sharing	Regional Market Participation
Washington	• Puget Sound Energy: Power Cost Adjustment Clause (PCA) accounts for differences in PSE's modified actual variable power costs relative to a power cost baseline. Variable costs include fuel, purchase power, hedging gains or losses, wheeling costs, sales to others, electricity taxes.[30] This mechanism would account for sharing of costs and benefits that is graduated over four levels of power cost variances. Annual Dead Band +/- $17 million of the Baseline Costs, Band 1 $17-$40 million above Baseline Costs shared 50% with customers, $17-$40 million below Baseline Costs shared 65% with customers. Band 2 +/- $40 million of Baseline Costs shared 90% with customers. • PacifiCorp: Power Cost Adjustment Mechanism (PCAM) calculates variances in Net Power Cost (NPC) including fuel, purchased power, transmission, and sales for resale. Symmetrical Deadband: Any PCAM variance between negative $4 million and positive $4 million will be absorbed by the Company. Asymmetrical Sharing Bands: The PCAM includes sharing of the PCAM variance as follows: Between $4 million and $10 million; shared 50 percent by customers and 50 percent by the Company; Greater than $10 million; shared 90 percent by customers and 10 percent by the Company; Between -$4 million and -$10 million; shared 75 percent by customers and 25 percent by the Company; and, Less than -$10 million; shared 90 percent by customers and 10 percent by the Company.[31] • Avista: Energy Recovery Mechanism (ERM) is used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for the utility's Washington customers. ERM sharing bands - the total power cost change is accumulated during the calendar year until the dead band of $4.0 million is reached. If total power cost changes exceed $4.0 million, 50 percent of increases or 75 percent decreases between $4.0 million and $10.0 million, and 90 percent of all changes in excess of $10.0 million are recorded as power cost deferrals and added to the power cost deferral-balancing account.[32] • Under the state's greenhouse gas emissions performance standards, electric utilities may defer costs for up to 24 months of qualifying new baseload generation resources and eligible renewable resources and related transmission that are not reflected in base rates.	None
Wisconsin	• Pursuant to Wis. Admin. Code § PSC 116.03, each of the five major investor-owned Wisconsin electric utilities (Northern States Power Co. - WI, or NSP-W, Wisconsin Power and Light	MISO

[30] Docket No. UE-260337, In the Matter of Puget Sound Energy, Inc. for Approval of its 2025 Power Cost Adjustment Annual Report, Exhibit A.
[31] Docket No. UE-140762, Final Order 09 Approving and Adopting Settlement Agreement; Authorizing and Requiring Tariff Filing, issued May 26, 2015.
[32] Docket No. UE-26215, In the Matter of the Petition of Avista Corporation d/b/a Avista Utilities Energy Recovery Mechanism Annual Review for 2025, Direct Testimony of Kevin Holland at 12.

State	Risk Sharing	Regional Market Participation
	Co., or WP&L, Madison Gas and Electric Co., or MG&E, Wisconsin Electric Power Co., or WEPCO, and Wisconsin Public Service Corp., or WPS) must file an annual proposed fuel cost for the next calendar year. Wisconsin Admin. Code § PSC 116.07 provides for an annual reconciliation of the utility's Commission-approved monitored fuel costs incurred in the plan year. Wisconsin Admin. Code §§ PSC 116.06(3) and 116.07(4)(a) further provide that a utility may collect from customers any actual, prudently incurred fuel costs that exceed its Commission-approved monitored fuel costs by more than 2.0 percent as measured on a cost per megawatt-hour (MWh) basis, provided it does not have excess revenues for the plan year as described under the fuel rules. Wisconsin Admin. Code §§ PSC 116.06(3) and 116.07(4) conversely provide that a utility must credit to customers any amount of the approved fuel cost plan that exceeds actual, prudently incurred fuel costs in excess of 2.0 percent. Excess revenues are defined as revenues in the year in question that provide utilities with a greater return on common equity than authorized by the PSC.[33] Fuel costs include fuel, energy market purchase, energy market sale, fuel cost price risk management, renewable resource credits, emission allowances, transmission and ancillary services.[34]	
Wyoming	• Black Hills/Cheyenne Light, Fuel & Power (CLF&P): Power Cost Adjustment (PCA) recovers fuel and purchased power costs as compared to a base year. Power costs are classified into two categories: Category 1 costs include steam production costs, and Category 2 costs include purchased power and capacity costs, transmission expenses, and certain other costs, and reflect any margins realized from off-system sales. Variances in Category 1 costs from a base level are allocated 85% to customers and 15% to shareholders. Variances in Category 2 costs are allocated 95% to customers and 5% to shareholders. Transmission cost adjustment mechanism (TCAM) recovers the incremental revenue requirement not included in base rates.[35] • PacifiCorp/Rocky Mountain Power: Energy Cost Adjustment Mechanism (ECAM) recovers net power costs (NPC) comprised of fuel, wholesale purchases and sales of electricity (including financial hedges), wheeling expenses, and wholesale purchases and sales of natural gas (including financial hedges); chemical costs; coal generation start-up fuel costs; production tax credits (PTCs); wheeling revenues; and the Wyoming qualifying facility adjustment. ECAM variances, excluding PTCs and wheeling	None

[33] Wisconsin Administrative Code § PSC 116.03.
https://docs.legis.wisconsin.gov/code/admin_code/psc/116/03
[34] Wisconsin Administrative Code § PSC 116.02.
https://docs.legis.wisconsin.gov/code/admin_code/psc/116/02
[35] Cheyenne Light, Fuel and Power Company d/b/a Black Hills Tariff, Energy Power Cost Adjustment and Transmission Cost Adjustment Mechanism, effective March 1, 2023.
https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/clfp_electric.pdf

State	Risk Sharing	Regional Market Participation
	revenues are recovered from or refunded to customers using an 80% sharing band. PTCs and wheeling revenue variances are recovered from or returned to customers at 100%.[36] Actual renewable energy and SO_2 credit revenue variances above or below the levels reflected in base rates are recovered from or refunded to customers 100%.[37] • Montana-Dakota Utilities (MDU): Power Supply Cost Adjustment (PSCA) collects from/credits to ratepayers variations in fuel and purchased power costs (demand, energy, ancillary services, and transmission charges), emissions costs that deviate from an established base level. Fuel supply related variances are shared 85% with customers and purchased power related variances are shared 95% with customers.[38]	

[36] Rocky Mountain Power, Energy Cost Adjustment Mechanism Schedule 95, effective July 1, 2026. https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf
[37] Rocky Mountain Power, REC and SO2 Revenue Adjustment Mechanism Schedule 93, effective June 1, 2025. https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/093_REC_and_SO2_Revenue_Adjustment_Mechanism.pdf
[38] Montana-Dakota Utilities Co. Tariff, Power Supply Cost Adjustment Rate 50, effective April 1, 2026. https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/Wyoming/Electric/WYelectric50.pdf

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2027-0077

AFFIDAVIT OF KEVIN D. GUNN

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

Kevin D. Gunn, being first duly sworn on his oath, states:

1. My name is Kevin D. Gunn. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Vice President – Regulatory and Government Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri West consisting of forty-one (41) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

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

Kevin D. Gunn

Subscribed and sworn before me this 3rd day of November 2026.

Notary Public

My commission expires: April 26, 2029

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