Exhibit No.:	______________
Issue(s):	FAC/Crossroads
Witness/Type of Exhibit:	Mantle/Surrebuttal
Sponsoring Party:	Public Counsel
Case No.:	ER-2024-0189

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EVERGY MISSOURI WEST, INC. D/B/A EVERGY MISSOURI WEST

CASE NO. ER-2024-0189

September 10, 2024

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SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE, P.E.

EVERGY MISSOURI WEST, INC.
FILE NO. ER-2024-0189

Q. Please state your name.

A. My name is Lena M. Mantle.

Q. Are you the same Lena M. Mantle that filed direct and rebuttal testimony in this case?

A. Yes, I am.

PURPOSE OF TESTIMONY

Q. What witnesses' testimony are you responding to in this surrebuttal testimony?

A. Regarding the appropriate fuel adjustment clause ("FAC") incentive mechanism, I respond to the rebuttal testimonies of Every Missouri West, Inc.'s ("Evergy West") witnesses Darrin R. Ives and Kevin D. Gunn. I also respond to the rebuttal testimony of Staff witness Brooke Mastrogiannis.

Regarding Evergy West's request to include the costs of transmission for Evergy West's Crossroads Energy Center ("Crossroads") located in Clarksdale, Mississippi for recovery from customers, I respond to the rebuttal testimonies of Evergy West witnesses Linda J. Nunn, Darrin R. Ives, and Cody VanderVelde.

Q. What recommendations to the Commission have you previously made in your direct and rebuttal testimonies in this case regarding Evergy West's FAC?

A. Regarding Evergy West's FAC, I made the following recommendations in my direct and rebuttal testimonies respectively:

1. The Commission should modify the sharing mechanism in Evergy West's FAC from 95% customers/5% Evergy West ("95/5") to 75% customers/25% Evergy West ("75/25");[1] and
2. The Commission approve Evergy West's base factor adjusted for OPC's positions:
   - A. No hedging costs/gains, SPP admin costs, or Crossroads transmission costs be included;
   - B. The miscellaneous charges and revenues in FERC account 447 as proposed by Staff witness Karen Lyons with Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("ARR") as proposed by OPC witness Angela Schaben in her rebuttal testimony be included instead of the amounts proposed by Evergy West; and
   - C. The denominator of the base factor should be the normalized net system input consistent with the billing determinants used to set rates in this case.[2]

Q. Do you make any changes to these recommendations or add any recommendations regarding the sharing mechanism of Evergy West's FAC in this testimony?

A. No. I do not.

[1] Direct testimony, page 1.
[2] Rebuttal testimony, page 2. For the remainder of this testimony, footnotes with page numbers refer to rebuttal testimony unless otherwise noted.

Q. What recommendations to the Commission have you previously made in your direct and rebuttal testimonies in this case regarding Evergy West's request to include the transmission costs of Crossroads for cost recovery from customers?

A. Regarding Evergy West's request to include the transmission costs of Crossroads for cost recovery from customers, I made the following recommendations in my direct and rebuttal testimonies:

1. The Commission should continue the rate base treatment of the Crossroads plant as ordered in case no. ER-2012-0175 and not include in revenue requirement or the FAC any part of the cost of transmitting electricity from Crossroads to Evergy West's customers in Missouri;[3]
2. The Commission remain silent regarding the renewal of Evergy West's contract with Entergy for firm transmission that allows the energy provided by Crossroads to reach the Southwest Power Pool ("SPP"); and
3. The Commission make it clear to Evergy West that it would be imprudent for Evergy West to remove Crossroads from service for Every West's customers and advise future Commissions to not allow the recovery of costs above what Evergy West would have incurred if Crossroads, without the cost of transmission, would have continued to be a generation asset for the rest of the life of the plant.[4]

Q. Do you have any changes to these recommendations in this surrebuttal testimony?

A. No. These recommendations remain the same.

[3] Direct testimony, page 1.
[4] Rebuttal testimony, page 2.

Q. Do you have any additional recommendations in this testimony?

A. I do not have a new recommendation in this testimony but will elaborate on one point from my prior recommendation. From my review of Evergy West's workpapers[5] for this testimony, Evergy West calculated the Net Present Value Revenue Requirement ("NPVRR") increase from the current treatment of Crossroads and to the cost of new generation as calculated by Evergy West would be $304.7 million. If Evergy West does not renew the Crossroads transmission contract, this should be the floor of the imprudence amount recommended to future Commissions.

75/25 FAC SHARING MECHANISM

Evergy West's Notice of Intent to File for a CCN

Q. Does Evergy West's September 3, 2024, notice regarding its intent to file an application for a certificate of Convenience and Necessity ("CCN")[6] demonstrate Evergy West's is now committed to hedging market costs with reliable power?

A. No. Evergy West's notice that it filed does not demonstrate a commitment to reliable power for its customers. Evergy West provided very little information about what it will be asking for in its CCN case. The only information provided in the filing is that Evergy West is intending to ask for two natural electrical production facilities. Its preferred resource plan has the addition of a half of a combined cycle plant in 2029 and a half of another combined cycle plant in 2030. It could be these two plants, but the filing gives no indication. There is no indication of the capacity of the two plants. The timing of the plant is unknown.

[5] Direct workpaper "CONF_Crossroads Workpaper_VandeVelde.xls"
[6] EA-2025-0075, *In the Matter of the Application of Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Permission and Approval of a Certificate of Public Convenience and Necessity For Natural Gas Electrical Production Facilities*.

Q. Does this filing change your position regarding Evergy West's reliance on the SPP energy market?

A. No, it does not. Evergy West has shared that there is no capacity available for purchase. This means that this new capacity will have to be built and not available in the near future thus not alleviating Evergy West's reliance on the SPP for electricity to meet its customers' needs.

<u>An Opportunity for Evergy West</u>

Q. Evergy witnesses Ives and Gunn believe a 75/25 sharing mechanism would be punitive.[7] Do you agree with this assessment?

A. No. a 75/25 sharing mechanism would not and should not be viewed as an effort to punish Evergy West. Instead, it should be seen as an opportunity for the company.

Q. How is it an opportunity?

A. Mr. Ives and Mr. Gunn are looking at the glass as half empty. They are assuming that costs will only increase, and a 75/25 mechanism would require Evergy West to pay 25% of that increase while the current 95/5 mechanism would only require it pay 5% of the increased costs.

However, that same glass is also half full. The 75/25 mechanism as proposed would be symmetrical. If Evergy West improved the efficiency and cost effectiveness of its fuel and purchased power procurement activities resulting in lower fuel and purchased power costs, then Evergy West would only be required to return 75% of the savings to customers and would get to retain 25% of the savings. This would result in Evergy West actually recovering more than the cost that it incurred thus giving it the opportunity to increase its earnings.

[7] Ives Rebuttal testimony, pages 4, 19, 21, and 23; Gunn rebuttal testimony, pages 2 and 10. Unless otherwise specified, all page numbers in the footnotes to this testimony refer to the rebuttal testimony of the identified witness.

Q. Would a 75/25 mechanism mean that Evergy West would only get to recover 75% of the net FAC costs it incurred??

A. No. Even if actual costs were 50% higher than what was included in permanent rates, with a 75/25 sharing mechanism, Evergy West would recover over 90% of its costs.

Q. Would you please explain this further?

A. Normalized FAC costs and revenues are included in the revenue requirement used to set base rates for investor-owned electric utilities in Missouri.[8] Customers are billed this normalized FAC amount regardless of the actual amount of FAC costs incurred. The FAC tracks the difference between the FAC costs included in revenue requirement and what is actually incurred. It is this difference that determines the FAC rate charged customers. With the 95/5 sharing mechanism, Evergy Wests bills its customers for 95% of that difference or gives 95% back to customers. Likewise, if the sharing mechanism is changed to 75/25, Evergy West would bill its customers 75% of any costs over what it collects in base rates but would only have to return 75% of any savings. With either of these mechanisms, if the actual FAC cost is below the FAC cost included in base rates, Evergy West would be allowed to keep some of that savings.

The graph below provides a visual representation of the percentage of cost recovery for the 95/5 sharing mechanism and the 75/25 sharing mechanism, given a range of deviations from the base costs included in permanent rates.

[8] 20 CSR 4240-20.090(1)(C) and (D).

Graph 1
Cost Recovery through Symmetrical Sharing Mechanisms

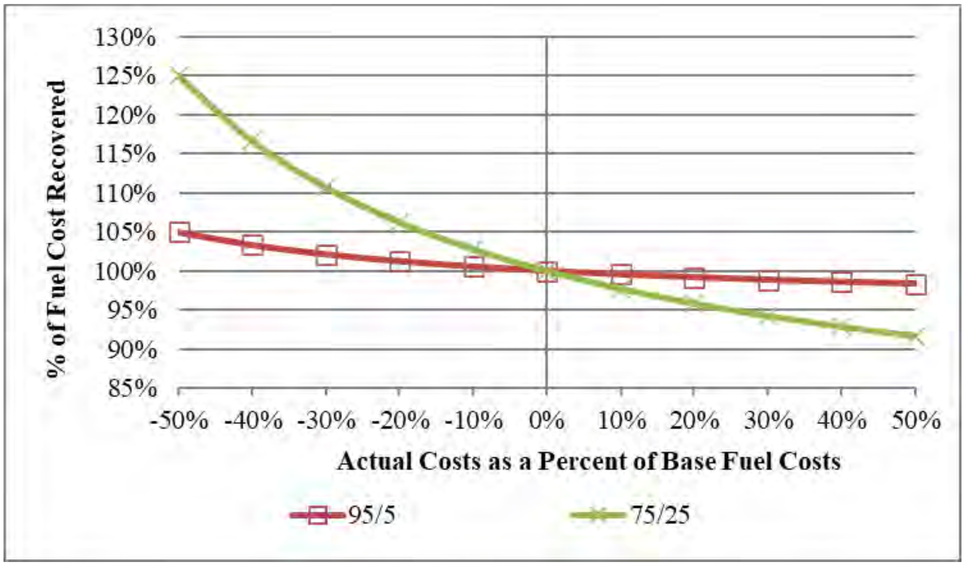

Table 1
Total Cost Recovery

Sharing Mechanism	Change in Fuel and Purchased Power Costs from Base										
	-50%	-40%	-30%	-20%	-10%	0%	10%	20%	30%	40%	50%
95/5	105%	103%	102%	101%	101%	100%	100%	99%	99%	99%	98%
75/25	125%	117%	111%	106%	103%	100%	98%	96%	94%	93%	92%

This graph shows, and the table reports, that if the actual costs were 20% below the costs in permanent rates (shown at -20%), Evergy West would get to recover 106% of the cost that it incurred with the 75/25 sharing mechanism but only 101% with the 95/5 sharing mechanism. The change to the 75/25 sharing mechanism would allow them to keep 5% more than the 95/5 sharing mechanism. If it reduced costs by 50%, then it would get to recover 125% of the cost it incurred with the 75/25 sharing mechanism which is 20% more than the 105% it would get to recover with the 95/5 sharing mechanism.

Q. Mr. Gunn asserts that "[e]xcessive risks can shake investor confidence and deter investment in the utility and its customers."[9] Would a 75/25 sharing mechanism put excessive risk on Evergy West?

A. No. As shown above, when costs increase 20%, Evergy West would still be able to recover 96% of the fuel and purchased power costs it incurred. If the costs increase 50%, with a 75/25 sharing mechanism Evergy West would still recover 92% of the costs. Mr. Ives and Mr. Gunn are focusing on this possibility of not recovering 6% of the costs[10] instead of focusing on the opportunity to recover 20% more than what it incurs if it reduces costs by 50%.[11]

Q. Could an increased opportunity to recover more than fuel and purchased power costs incurred increase investor confidence and investment in Evergy West?

A. It seems to me that it could.

Q. Are fuel and purchased power expenses volatile and beyond the control of the utility as expressed by Mr. Gunn?[12]

A. Not completely. While it is true that the spot market prices of natural gas, oil, uranium, and coal are beyond the control of the utility, utilities can enter into contracts for delivery of some amounts of these fuels at a predetermined price to mitigate the volatility of purchasing these fuels on their respective spot market. In addition, utilities may enter into financial hedges to further mitigate volatility. When done correctly, hedging can provide stability and savings, but if done incorrectly, it can result in unnecessary costs.[13]

[9] Page 10.
[10] The difference between what Evergy West would recover given a 95/5 sharing mechanism (98%) and what it would recover given a 75/5 sharing mechanism (92%).
[11] The difference between what Evergy West would retain given a 95/5 sharing mechanism (5%) and what it would retain given a 75/5 sharing mechanism (25%).
[12] Page 5.
[13] See the direct and surrebuttal testimonies of OPC witness John S. Riley for OPC's position regarding Evergy West's hedging practices.

However, Evergy West's business is not providing natural gas, oil, uranium, or coal to its customers. Evergy West is in the business of providing electricity to customers. It makes decisions regarding the conversion of these fuels to electricity within the confines of legislative mandates and restrictions. Evergy West decides what type of generation plant to build and when to build it. Evergy West determines what fuel will be used to generate electricity. Evergy West decides whether or not to retire and not to replace. Evergy West decides to rely on electricity purchased on the market without having electricity to sell back into the market to generate revenues to offset these costs. These are long- and short-term decisions that are made by Evergy West that impact the risk of volatile markets. Having an FAC with a 95/5 sharing mechanism moves all but a very small amount of the risks associated with these decisions and the cost of fuel to the customers.[14] A 75/25 sharing mechanism would move a small portion of that risk back to the decision maker – Evergy West.[15]

An analogy can be made to staying warm in the winter. We live where the temperature can be bitter cold in the winter. No one has control over the day-to-day fluctuations in outside temperatures. Yet we do have choices we can make that help us stay warm in the winter. We make long-term decisions about the level of insulation in our homes and how we are going to heat our home. We make shorter term decisions about what coats to buy and clothes to have available. We make even shorter-term decisions about what temperature to set the thermostat in our homes at. We can prepare and, as a result, stay warm even in the bitterest cold despite not having control over the outside temperature.

Evergy West does not have control over fuel prices. However, it does have control over many decisions that it makes, long- and short-term, that effects the volatility and cost to the customer. This is where a sharing mechanism can

[14] See Table 1 above. Costs can increase 50% and Evergy West would still recover 98% of the costs.
[15] Even with a sharing mechanism of 75/25, when costs increase 50% Evergy West would recover 92% of the costs.

influence the cost to the consumer. The less risk regarding cost that is assumed by Evergy West, the greater the potential for a moral hazard. The Rocky Mountain Institute, in its handbook for utility regulators, *Strategies for Encouraging Good Fuel-Cost Management,*[16] states it this way:

> FACs create a situation that economists refer to as "moral hazard," which exists when one party makes the decisions while another bears the risk of those decisions. By insulating the utility from the risks of poor fuel-cost management decisions — and also not rewarding the utility for making good decisions — a FAC gives it little incentive to work hard to reduce fuel costs. By transforming fuel costs from a major business expense to a side consideration, FACs enable poor fuel-cost management decisions that undermine affordability and perpetuate utility reliance on carbon-intensive fuel-based generation resources.

An FAC with a 95/5 sharing mechanism creates a moral hazard potential since the utility will still recover over 98% of its fuel and purchased power costs when they increase as much as 50% above the normalized costs included in the base. A 95/5 sharing mechanism moves FAC costs from a major business expense to a side consideration with very little impact on Evergy West.

A 75/25 sharing mechanism lessens the moral hazard potential while still assuring Evergy West of substantial cost recovery of 92% when costs increase 50% above the base. Changing the sharing mechanism to 75/25 increases both the cost risk to Evergy West but also provides greater reward for good decisions that increase the efficiency and cost-effectiveness of converting the fuel, over which it has no control over the cost, to the commodity its customers rely on it for - electricity.

[16] Attached as Schedule LMM-S-1.

<u>Evergy West is Not a "Normal" Utility</u>

Q. Both Evergy West and the Staff point out that a 75/25 incentive mechanism is not within the industry norms.[17] Is this a reason to not change the incentive mechanism to a 75/25 sharing mechanism?

A. No. Evergy West does not operate within industry norms therefore it is illogical to restrict its FAC to the industry norm. I discussed at great length in my direct and rebuttal testimonies how Evergy West's decisions to rely on the energy market has transferred substantial risk to its customers so I will not expand on that again in this testimony. No witness has provided an example of even one electric utility that exposes its customers as much to the risk of the energy market as Evergy West does. These decisions put Evergy West outside the industry norms for meeting customers' load requirements in states that have vertically integrated electric utilities.

When Evergy West's generation resource choices place it with the other "normal" utilities that do not rely on the market to substantially meet its customers' needs, then it will be more appropriate to compare its FAC to industry norms.

Q. Staff's witness Mastrogiannis provided testimony that showed the Empire District Electric Company d/b/a Liberty Utilities ("Liberty") had a prudence period where its short-term energy costs were greater than its off-system sales revenue.[18] Does this signify that Liberty is also outside the industry norm?

A. No.

Q. Would you explain why?

A. First, the data that Ms. Mastrogiannis provided is not comparable to the data that I provided in my direct testimony for Evergy West. The non-firm short term energy

[17] Staff witness Mastrogiannis rebuttal, page 12; Evergy West witness Gunn, page 2 – 3; Evergy West witness Ives, pages 20 – 21.
[18] Page 8.

costs and off-system sales revenues provided in Ms. Mastrogiannis' table for prudence case no. EO-2021-0281 contains the costs for Strom Uri that were determined to be extraordinary.[19] I have duplicated the table from page 8 of Ms. Mastrogiannis' rebuttal testimony below with a column that shows the amounts for this prudence period with the extraordinary costs removed.

Table 2
Liberty's Energy Market Margin

FAC Prudence Case No.	Actual Margin	Margin w/o Storm Uri
EO-2018-0244	$14,781,374	$14,781,374
EO-2020-0059	$13,351,380	$13,351,380
EO-2021-0281	($66,978,252)	($9,306,791)
EO-2023-0087	$20,424,065	$20,424,065
Total	($18,421,433)	$39,250,029

A comparison of these margins to the margins of the last four prudence reviews of Liberty, Evergy West, Evergy Metro and Ameren Missouri reveals the differences between the margins of the four utilities.

[19] The prudence time period for case no. EO-2021-0281 was September 1, 2019 through February 28, 2021.

Table 3
Market Margins of Missouri Investor-Owned Utilities

Prudence Period[20]	Liberty	Evergy West	Evergy Metro	Ameren Missouri
1	$14,781,374	($130,412,043)	$81,993,279	$67,610,336
2	13,351,380	(177,300,895)	114,862,977	47,426,181
3	(9,306,791)	(140,111,690)	98,534,153	172,182,584
4	20,424,065	(299,775,720)	169,852,295	236,488,572
Total	$39,250,029	($747,600,348)	$465,242,704	$523,707,673

As shown in this table, Liberty's margin for one prudence period was negative. Evergy West's margin was negative all four prudence periods. In addition, the magnitude of the negative margin is vastly different. Looking over these last four prudence periods, Liberty is not similar to Evergy West over the last four prudence periods other than in the extreme of Storm Uri, they both incurred extraordinary costs.

Q. Why did you include margins for Evergy Metro and Ameren Missouri[21] in this table?

A. To give a complete picture of the market margin for all of Missouri investor-owned electric utilities. It is easy to see from this table how outside the "norm" Every West is from the other utilities. Evergy Metro and Ameren Missouri supply more energy into the market than they purchase. Liberty does not rely on the market for energy but takes advantage of the market when it is needed. In total, over its last

[20] Prudence period cases:

	Liberty	Evergy West	Evergy Metro	Ameren Missouri
1	EO-2018-0244	EO-2019-0067	EO-2019-0068	EO-2019-0257
2	EO-2020-0059	EO-2020-0262	EO-2020-0263	EO-2021-0060
3	EO-2021-0281	EO-2022-0065	EO-2022-0064	EO-2022-0236
4	EO-2023-0087	EO-2023-0277	EO-2023-0276	EO-2024-0053

[21] Not normalized for Storm Uri impacts. Every Metro and Ameren Missouri provided more energy into the markets than they used during Storm Uri.

four prudence periods, Liberty has generated more revenues from the market than costs.

Evergy West's customers are exposed to a greater level of energy market risk than other investor-owned electric utility in the State of Missouri. The 95/5 sharing mechanism in the FACs of Evergy Metro, Liberty, and Ameren Missouri does not expose their customers to as much risk as a 95/5 sharing mechanism does for Evergy West because they have chosen to hedge that risk with cost-effective generation. A 75/25 sharing mechanism would move some of the risk from customers that have no control over the fuel and purchased power costs and provide an opportunity for Evergy West to increase its earnings.

<u>Sharing Mechanism Is A Tool Not A Weapon</u>

Q. What is your response to Mr. Gunn's characterization of your recommendation for a change from the 95/5 sharing mechanism as weaponizing the FAC?[22]

A. The Missouri General Assembly included in Section 386.266.1 RSMo. a provision that allows the Commission to include an incentive mechanism in Evergy West's FAC that is designed "to improve the efficiency and cost-effectiveness of [Evergy West's] fuel and purchased-power procurement activities." It does not prescribe what the incentive mechanism should be nor does it say that, once established, the sharing mechanism can never be changed.

I would characterize the sharing mechanism, not as a weapon, but as a tool. The 95/5 sharing mechanism for Evergy West is akin to using a screwdriver made for eyeglasses to tighten the screw in a gate hinge. It is simply too small to have an effect. A larger screwdriver may look like a weapon, but it is really just the right tool for the job.

[22] Page 11.

If the sharing mechanism is changed to 75/25 and Evergy West finds ways to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities, then this mechanism will provide Evergy West with a higher return. If the SPP energy market prices jump, then this sharing mechanism would reduce Evergy West's return giving it an incentive to hedge this market.

Likewise, approving the sharing mechanism would give Evergy West the opportunity to earn not just a sufficient return, but a higher return thus incentivizing it to become more efficient and cost-effective in its fuel and purchased power activities.

Q. Would this change shake investors' confidence and deter investment in Evergy West as opined by Mr. Gunn?[23]

A. What shakes investors' confidence and deter investment in Evergy West is subjective. The Commission has never changed the sharing mechanism before so the impact is unknown. Investment decisions are complex and have many interacting, interdependent aspects.

However, the Commission should not obfuscate to financial rating agencies its responsibilities of assuring safe and adequate service at just and reasonable rates for Missouri citizens. The reason investors invest is to make the most money with the smallest risk not to provide safe and adequate electricity service at just and reasonable rates, yet it is only the latter that the Commission is legally obligated to ensure.

[23] Page 10.

History of Requests to Change the FAC Sharing Mechanism

Q. Mr. Gunn states that your requests for changing the 95/5 sharing mechanism have been dismissed by the Commission in Evergy's recent rate cases.[24] Is he correct?

A. No. The last Evergy West case that the Commission issued a decision in regarding a change in Evergy West's FAC sharing mechanism was four rate cases ago in case no. ER-2012-0175. The order was effective over a decade ago on January 9, 2013. Since this order was issued, Evergy West's dependence on others for energy for its customers has increased from 22%[25] in 2013 to 56% in Evergy West's last resource plan.[26] The big change that enabled Evergy West to rely on electricity that others generate was the SPP integrated hourly energy market that began on March 1, 2014, fourteen months after that Commission decision.

In addition, since that Commission decision in case no. ER-2012-0175, Evergy West has been found imprudent once by this Commission in FAC prudency audit cases and has entered into settlements in two other Staff prudent audit cases returning money to its customers[27] as Staff witness Mastrogiannis describes in her rebuttal testimony.[28]

Q. Are the Ameren Missouri rate cases, ER-2011-0028, ER-2012-0166, and ER-2014-0258, Mr. Gunn referenced in his testimony relevant to this case?

A. No for several reasons.

First and foremost, these were Ameren Missouri cases, not Evergy West or its predecessor rate cases. Ameren Missouri is a different utility than Evergy West.

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[24] Page 9.
[25] Case no. EO-2013-0538, *In the Matter of the 2013 KCP&L Greater Missouri Operations Company Annual IRP Update Report,* 2013 Annual Update, Tables 1 and 2.
[26] EO-2024-0154, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2024 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*, Volume 1 - Evergy Missouri West Executive Summary, Tables 1 and 2.
[27] There was no admission of imprudence with these settlements.
[28] Page 7.

Ameren Missouri operates differently from Evergy West. Ameren Missouri has historically been able to hedge against energy market costs by being long on capacity and energy, unlike Evergy West.

Mr. Gunn's testimony regarding OPC's position in these cases is also incorrect. In case no. ER-2012-0166, OPC did not take a position regarding the sharing mechanism of Ameren Missouri's FAC. In the third of these cases, ER-2014-0258, Mr. Gunn failed to point out that, while the OPC did file to change the sharing mechanism to 90/10 sharing, OPC and Ameren Missouri entered into a Stipulation and Agreement that the sharing mechanism remain 95/5.[29] It was Staff that took this issue to the Commission for its decision. The *Report and Order* in that case became effective on May 12, 2015, nearly a decade ago.

Over that decade Evergy West has not added reliable energy resources to its portfolio. Instead, it has become more reliant on intermittent wind resources and retired plants without comparable replacements. Ameren Missouri will soon retire one of its coal energy centers. However, it is not relying on the energy market for long to replace that energy resource. Ameren Missouri currently has a CCN case before the Commission[30] requesting it authorize the addition of an 800 MW multi-unit simple cycle natural gas electric generation facility. Unlike Evergy West that waited six years after the retirement of its Sibley plant, Ameren Missouri filed for this CCN before its coal plant had retired. This demonstrates Ameren Missouri's commitment to hedging the energy market with reliable generation even though it has an FAC in which energy market purchase power costs are flowed through to customers.

[29] ER-2014-0258, *Report and Order*, page 108.
[30] EA-2024-0237, *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and Certificates of Public Convenience and Necessity Authorizing it to Construct a Simple Cycle Natural Gas Generation Facility.*

Q. Staff witness Mastrogiannis mentions that the Commission had not issued an order in Evergy West's prudence review case EO-2023-0277 at the time she wrote her rebuttal testimony.[31] Has the Commission issued an order in that case since rebuttal testimony was filed in this case?

A. Yes, the Commission issued its order in case no. EO-2023-0277 on August 7, 2024, the day after rebuttal testimony was filed in this case. In its order, the Commission found that Evergy West's FAC costs for the period of June 1, 2021 through November 30, 2022 were prudent.

Q. Then why should the Commission change the sharing mechanism in this case?

A. Section 386.266.1 RSMo. does not require a finding of imprudence to determine a sharing mechanism is needed or should be changed. Prudent does not necessarily mean cost-effective or efficient. There is a range of prudent decisions with some being more prudent and cost-effective than others. The Commission recognized this in its *Report and Order* in case no. EO-2023-0277 when it encouraged Evergy West and Evergy Metro to consider merging saying that "[t]his would give [Evergy West] customers greater access to [Evergy Metro's] generation capacity, and should thereby reduce FAC costs for [Evergy West] customers."[32] The Commission should further recognize in this case that efficiencies can be gained with the incentives offered with a 75/25 sharing mechanism in Evergy West's FAC.

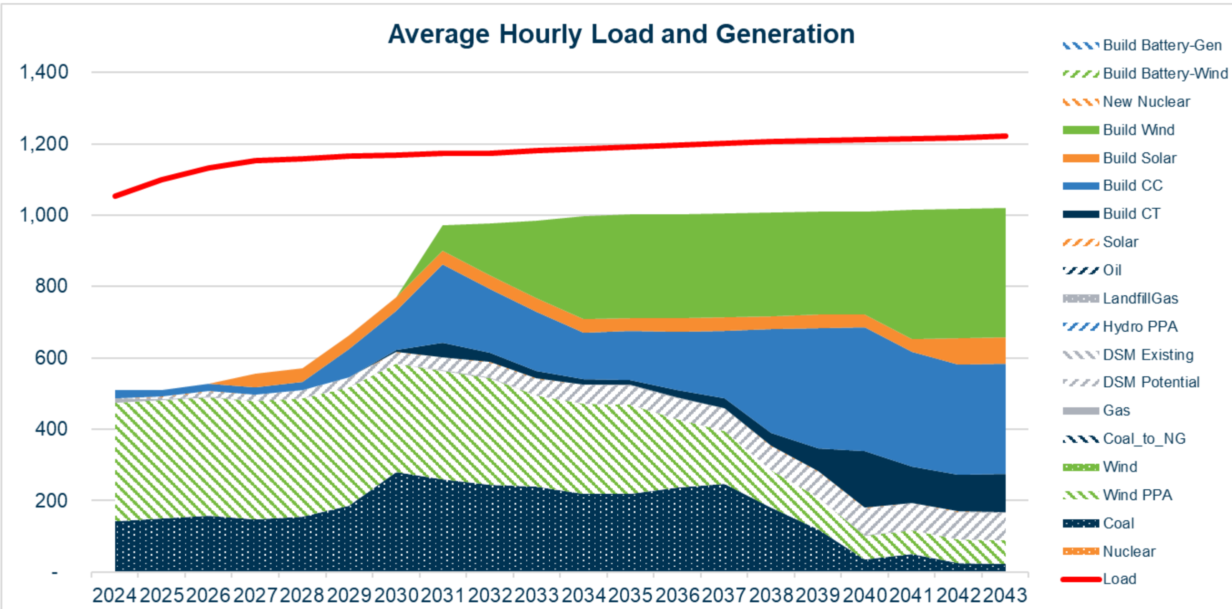
Q. What are other steps that Evergy West can take to be more cost-effective in its fuel cost and purchased power procurement?

A. There are many day-to-day steps Evergy West can take. However, perhaps the most long-lasting step it can take is to acquire more cost-effective, dispatchable generation resources that provide low-cost electricity to sell into the market. Graph

[31] Page 7.
[32] Page 14.

2 below shows the average hourly load[33] and generation[34] for each year of Evergy West's preferred plan as filed in case no. EO-2024-0154.[35]

Graph 2
Evergy West



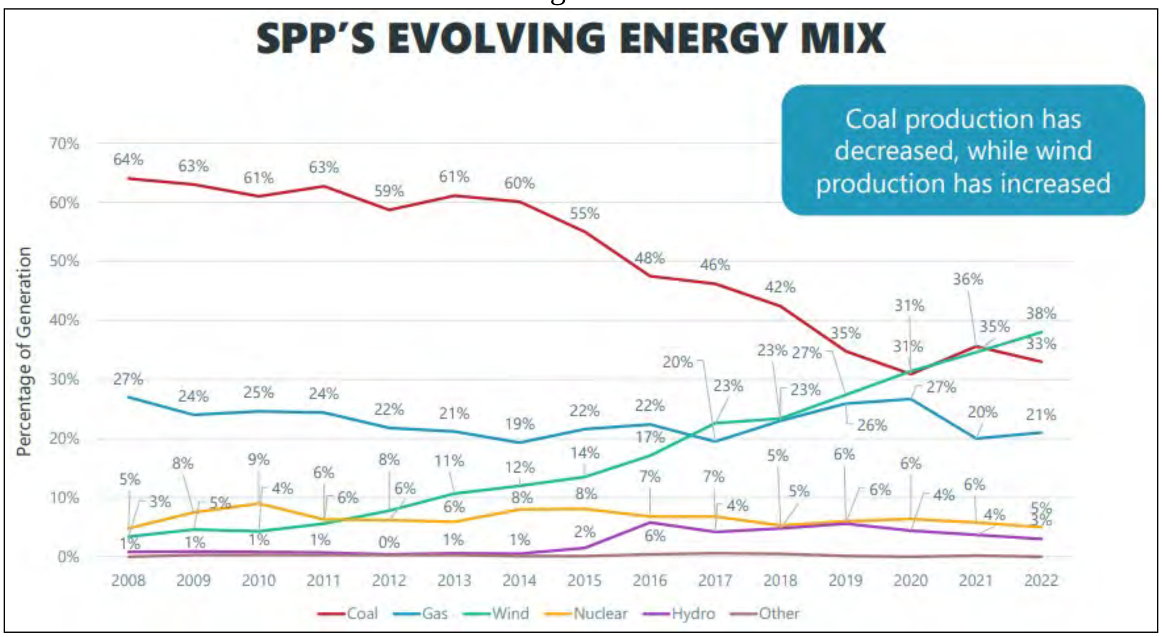
What this graph shows is that even with the addition of a portion of the Dogwood combined cycle plant,[36] Evergy West does not plan to have enough generation to meet its customers' energy load in any year throughout the 20-year planning horizon. The difference between the line on the top (average hourly load) and average hourly generation shaded areas below is the amount of energy that Evergy West will not be able to provide with its own resources. This is perhaps the biggest risk in Evergy West's preferred plan. Not only is there a risk in the price but there is also a risk in whether or not other SPP members will have generation to sell into the market for Evergy West to purchase.

[33] Sum of the hourly loads divided by the number of hours in the year (MWh/hr).
[34] Sum of the hourly generation divided by the number of hours in the year (MWh/hr).
[35] From Evergy West workpaper "MET CAAB Plan."
[36] The energy provided by Dogwood is shown as "Build CC" in this graph.

Q. Why do you believe that there may not be electricity for Evergy West to purchase in the future?

A. The following three figures were included in the SPP's presentation[37] at the Commission's recent Power MO Resource Adequacy Summit.

Figure 1



[37] https://psc.mo.gov/CMSInternetData/ConsumerInformation/SPP.pdf, slides 8, 12, and 13.

Figure 2

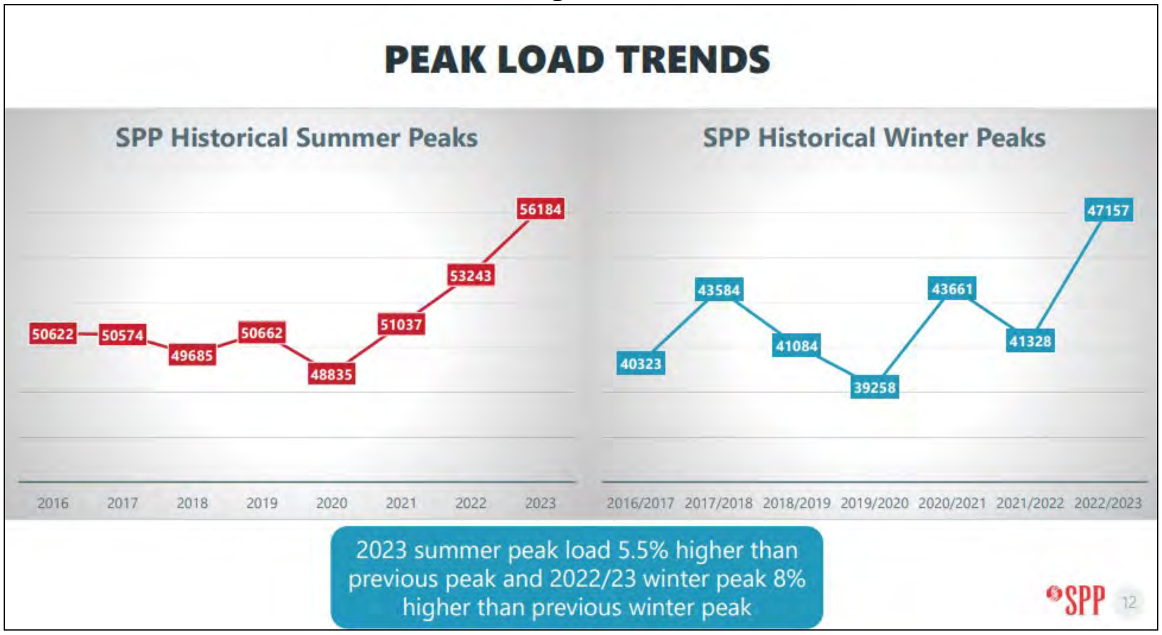
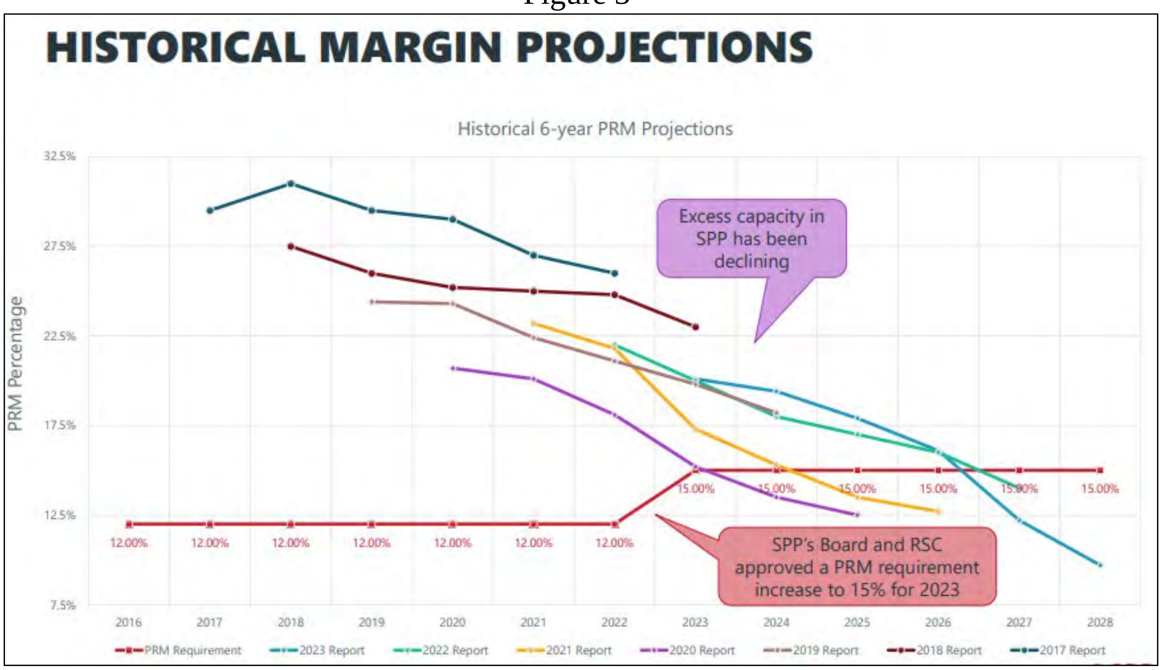


Figure 3

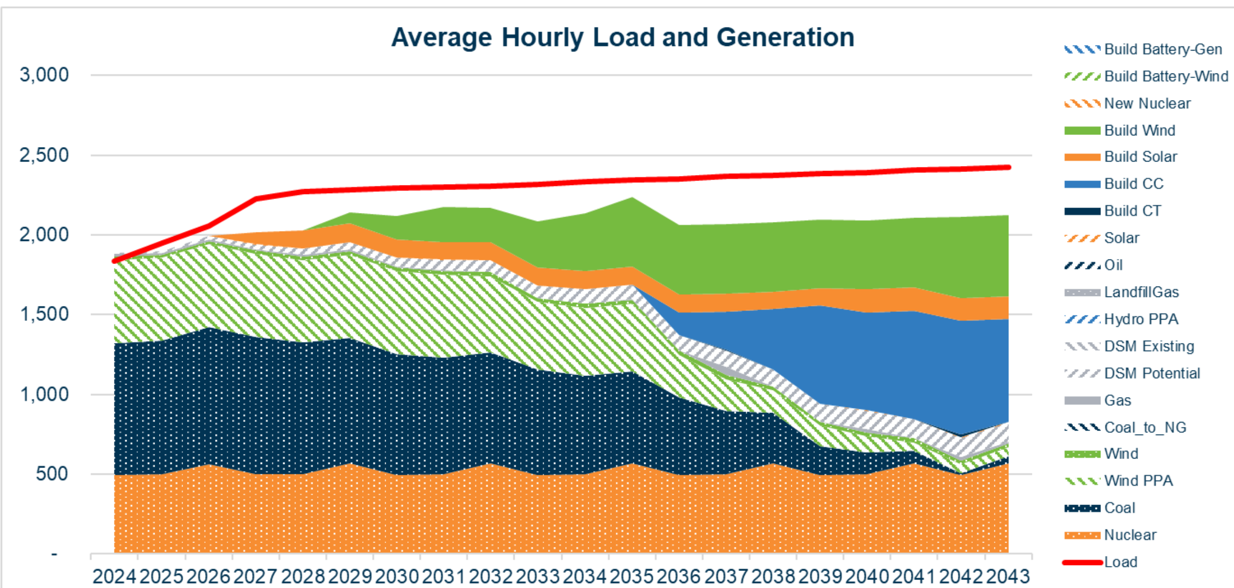


These slides show a rapidly decreasing amount of dispatchable generation with an increasing amount of intermittent generation, an increase in both summer and winter peaks which all contribute to the decrease in planning reserve margins for the SPP. A decrease in planning margin equates to less available generation.

Q. Would the combined utilities of Evergy West and Evergy Metro be able to meet the energy needs of their combined customers?

A. No, they would not. According to the preferred plan of Evergy Metro detailed in its triennial resource plan filing, case no. EO-2024-0153, Evergy Metro will not have the energy it needs to meet its customers' needs as soon as 2025. This is shown in Graph 3 below.[38]

Graph 3
Evergy Metro



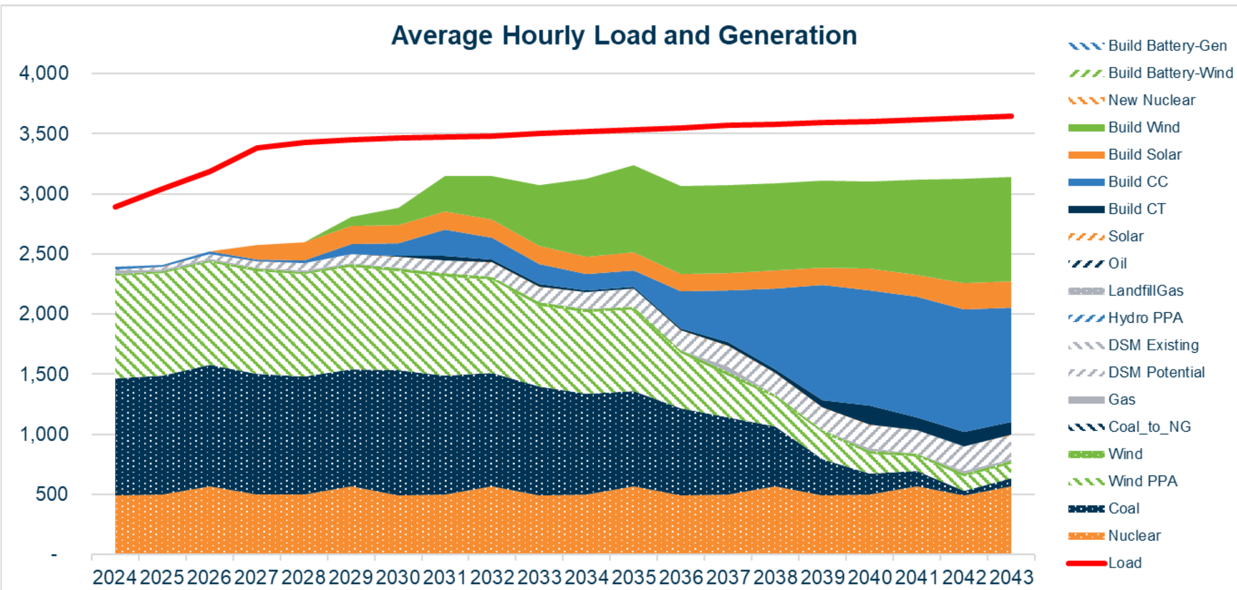
What this graph shows is that Evergy Metro projects it too will no longer be able to generate more energy than its customers need beginning in 2025 and that it plans

[38] Evergy Metro workpaper "MET CAAB Plan." Average load is the sum of the hourly loads divided by the number of hours in the year (MWh/hr). Average generation is the sum of the hourly generation divided by the number of hours in the year (MWh/hr).

on relying on the energy market to meet a portion of its customers' energy needs through the rest of the 20-year planning horizon.

Graph 4 below is the combined average load and generation of the two utilities preferred resource plans.

Graph 4
Evergy West and Evergy Metro



These two utilities combined will be relying on purchasing almost 10% to 24% of their customers' energy needs annually over the next 20 years.

Q. If combining the utilities will not enable Evergy West to meet its needs, then what actions can Evergy West take to meet its customers' needs?

A. The way to reduce this risk is to build or acquire generation. The problem is that there is little out there to acquire and it takes time to build.

Q. Since it takes time to build generation resources and there is nothing to acquire, would the 75/25 sharing mechanism be a penalty until more generation can be built?

A. No. Energy market prices could go down as they have since 2022.[39] If that does occur, then Evergy West would, in recognition of it being allocated more of the risk of the market, get to keep 25% of the savings from lower market prices. Evergy West's decisions to rely on market power have increased the risk of volatile prices. Customers have no say in the amount of market risk Evergy West is asking the Commission to put on its customers. Evergy West should assume more of that risk.

Because Evergy West will be assuming more of the risk of market procurement of energy, it will also receive a greater reward for any efficiencies it can achieve. The increased risk being placed on Evergy West will be relieved as it adds cost-effective generation. As Evergy West is able to receive payments from the SPP for this generation, then Evergy West's risk and the risks to the customers of market volatility will be reduced.

Q. What is your response to Mr. Ives' assertion that OPC's relentless repetition regarding Evergy West's lack of generation is distracting and inefficient?[40]

A. Given the Commission's recent Power Mo Resource Adequacy Summit, OPC's call for Evergy West to reduce its reliance on the SPP energy market is right on target. Given SPP's 2024 Resource Adequacy Report that there will be no excess capacity in 2027,[41] it seems that any party that is claiming more generation is not needed is attempting to distract the Commission's attention from its lack of resources. No excess capacity and higher demand means higher energy prices. NERC's long-term reliability risk assessment of the SPP's reliability as "elevated"

[39] See rebuttal testimony of Evergy witness Foo, page 4.
[40] Page 20.
[41] https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf, page 2.

supports OPC's position.[42] Staff too is concerned with the risk to customers given Evergy West's resource decisions shifting away from dispatchable thermal resources to renewable, non-dispatchable generation.[43]

What Mr. Ives characterized as being distracting and inefficient, the Commission has expressed appreciation for. In its on July 18, 2024, Agenda discussion of case no. EO-2023-0277,[44] all the Commissioners expressed concern with Evergy West's lack of resources to meet its customers' needs. Commissioner Holsman ended his comments with the statement:

> To OPC's credit, I thought in the hearing, you know, the suggestion that there could be harm is real. The disallowance in my mind doesn't reflect that there was harm, um, from a cost perspective, but I think that OPC bringing this, you know, to the forefront and requiring this conversation will hopefully then drive the resource adequacy Summit, summit to get us a little further down a path that we won't be here in the future because something has changed. And I think that is what OPC is saying, is that we have been going along this route and nothing has changed and we have been kind of, you know, gambling a little bit that we are not going to get caught up in a, you know, price issue. And so we should take this opportunity to get on a path where we don't have this risk in the future.

To which Chair Hahn replied, "Absolutely."

Chair Hahn also commented at the Commission's Agenda meeting that she was appreciative of OPC for bringing the issue of Evergy West's resource adequacy to the Commission.[45]

[42] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf, page 6.
[43] Case no. EO-2024-0154, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2024 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*, Staff Report, pages 16 - 17.
[44] https://psc.mo.gov/VideoDetail.aspx?Id=6743, beginning at minute 41.
[45] https://psc.mo.gov/VideoDetail.aspx?Id=6758, minute 32

Q. Are you aware of any issue the Commission has ruled on that Evergy West has relentlessly requested a reversal of after a Commission order?

A. There are many such issues. The most obvious in this case is Evergy West's request for Crossroads transmission costs to be included in its revenue requirement. The Commission has issued not one, but two orders[46] that it was imprudent to build a plant so far away and disallowed the inclusion of this cost in Evergy West's revenue requirement. Yet Evergy West in the next two general rate cases, nos. ER-2016-0156 and ER-2018-0146, asked for Crossroads transmission costs to be included in its revenue requirement and Evergy West's FAC so that customers would not only pay for transmission costs but also 95% of any increases. Case no. ER-2022-0130 is the only general rate increase case filed by Evergy West since the Commission ordered no cost recovery of Crossroads transmission costs that Evergy West has not asked for the costs to be included.

In the current case, Evergy West has taken its request for Crossroads transmission requests to be included in its revenue requirement to a new level by threatening the Commission that if Crossroads transmission costs are not included in revenue requirement, it will take actions that will increase customers' bills even more.[47]

Evergy West has been persistent too in requesting SPP administrative costs be included in its FAC despite the Commission's order in case no. ER-2014-0370 that these fees are not directly linked to fuel and purchased power costs.[48] It has also been persistent in asking for cost trackers too. These are just the few issues that I am aware of that Evergy West has been persistent in requesting.

[46] Case nos. ER-2010-0356 and ER-2012-0175.
[47] My response to Evergy West's rebuttal testimony regarding its request for Crossroads is provided later in this testimony.
[48] See surrebuttal testimony of OPC witness Angela Schaben.

Other Jurisdictions

Q. Staff witness Mastrogiannis asserts in response to your direct testimony that data from other jurisdictions provide information on the effectiveness of the 95/5 sharing mechanism for Evergy West.[49] Do you agree with Ms. Mastrogiannis that incentive mechanisms of other jurisdictions provide the Commission information on the appropriate sharing mechanism to induce Evergy West to act more efficiently and increase cost-effectiveness of its fuel and purchased power procurement activities?

A. No. My direct testimony that she was responding to was that there is only one data point regarding the impact of a sharing mechanism available for Evergy West and that one data point is a sharing mechanism of 95/5. Therefore, we do not have information on how a change in the sharing mechanism would affect Evergy West's fuel and purchased power procurement activities. We simply know the results regarding the actions of Evergy West to one sharing mechanism: 95/5. We know that the sharing mechanism has not induced Evergy West to hedge its purchased power costs with generation resources that can meet its customers' energy requirements. We also know that not having dispatchable generation greatly impacted the FAC costs Evergy West incurred during Storm Uri; costs that its customers will be paying for over the next 15 years.

Q. Should the fact that only a few of the FACs of these other jurisdictions have a sharing mechanism inform this Commission regarding the sharing mechanism of Evergy West?

A. No. Neither Staff witness Mastrogiannis, nor Evergy Witnesses Ives and Gunn provide the Commission any details regarding the various FAC mechanisms of other states. They do not provide any information regarding whether or not the FAC of other jurisdictions is statutory or if a sharing mechanism is even allowed

[49] Page 10.

by statute as it is in Missouri. Ms. Mastrogiannis provides the sources of her information as the document that I have attached as Schedule LMM-S-1 and the FAC Primer Report published by the PSS Finance Lab *Can We Share the Cost of Fuel?*[50] Neither of these reports provide detailed information regarding the authority or history of the FACs in each jurisdiction that has incentive mechanisms or if the jurisdictions that do not have a sharing mechanism even have the authority to include a sharing mechanism in their FACs.

Our Commission has been given a tool by the Missouri General Assembly. The fact that many other jurisdictions were not given this tool is not a reason for this Commission to set it aside and not use this tool to its full advantage for both the utility and its customers.

Changes to the Design of Evergy West's FAC Mechanism

Q. Would you summarize the reasons Mr. Ives provides that he believes necessitates a change to the design of Evergy West's FAC? [51]

A. Mr. Ives lists a number of what he perceives as problems with the current FAC mechanism. It seems that most could be summed up in that Missouri's FAC is different from FACs in other jurisdictions in the United States that Mr. Ives would prefer; the bill line item of Evergy West's FAC does not provide direct fuel signals; and having an FAC that is the difference between an amount set in permanent rates, and what actually occurs creates an opportunity for manipulation.

Q. Do you see a need for the Commission to consider doing away with the rebasing of fuel and purchased power costs and revenues in Evergy West's FAC?

A. No, I do not.

[50] https://www.pssfinancelab.com/post/can-we-share-the-cost-of-fuel, attached to this testimony as LMM-S-2. Note that my FAC whitepaper, *Electric Utility Fuel Adjustment Clause in Missouri: History and Application*, is cited as the source regarding Missouri's FACs in both of these reports.
[51] Pages 22-23.

Q. Is being different from other jurisdictions a reason to change the FAC mechanism of Missouri electric utilities?

A. No. Missouri's FACs should be designed to meet Section 386.266 RSMo. It should include the design requirements and the customer protections provided for in this section. Missouri was late in the game regarding a fuel adjustment clause. Our General Assembly had many examples of how an FAC could be implemented and how they should be operated. It recognized the potential moral hazard of the electric utility being able to recover all of its fuel and purchased power costs through an FAC and included the ability for the Commission to include an incentive mechanism.

Q. Do you agree with Mr. Ives that the FAC mechanism does not send direct fuel price signals?

A. Yes. However, the purpose of an FAC is not to send fuel price signals.[52] The purpose of an FAC is to reduce the electric utility's risk of not recovering fuel and purchased power costs.

An FAC cannot provide timely price signals. Energy market prices change every five minutes and fluctuate across the day. The prices on any given day vary from the day before. Evergy West does not know the costs incurred until the end of the calendar month and then needs another calendar month to be able to provide the change in fuel and purchased power costs to the Commission. Even if the Commission could approve a change to the charge in a week, it is not applied to customers' bills until the next billing cycle which could be up to four weeks later.

If the Commission wants to send price signals to customers, it should not look to the FAC to accomplish that purpose.

[52] For additional discussion, see pages 10 – 11 of the whitepaper *Electric Utility Fuel Adjustment Clause in Missouri: History and Application* attached to my direct testimony as Schedule LMM-D-2.

Q. Does the current design allow for manipulation of permanent rates as Mr. Ives asserts?

A. Yes, it does. As I explained in my rebuttal testimony, I believe that Evergy West has used the current design to manipulate its rate increases in the past and is manipulating its normalized fuel amounts in this case to keep the rate increase in this case to a minimum knowing that it can recover 95% of the difference between a low normalized cost and the actual cost through its FAC.

Q. Is your recommendation of a 75/25 sharing mechanism such a manipulation attempt as Mr. Ives seems to be implying?[53]

A. No. Since over 70% of the costs in Evergy West's FAC base estimates are for net purchased power costs, volatility and price increases in the energy market compose the greatest risk in these costs. This is a direct result of Evergy West's resource planning decisions in the past to rely on the energy market instead of acquiring dispatchable generation resources. The current 95/5 sharing puts almost all of that risk on its customers.

If the sharing mechanism was changed to 75/25, customers would still take on 75% of the risk but Evergy West would assume 25% of the risk. Thus, any actions that would result in a reduction of risk would provide a real benefit for Evergy West.

Q. Would addressing FAC costs outside of base rates through the fuel clause mechanism as Mr. Ives proposes alleviate his concerns?

A. No. Section 386.266 requires the FAC to be an adjustment mechanism. As I stated earlier, no FAC mechanism could provide a timely price signal. At the very least it would be conveying the price from three months prior. Manipulation would still occur as parties disagree over what costs should be included as a fuel cost and what costs should not.

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[53] Pages 22 – 23.

However, if the Commission determined that it should consider changing the design of the mechanism, OPC will work with the Staff and the utilities on redesigning the mechanism.

Summary of FAC Surrebuttal

Q. Would you summarize your surrebuttal regarding Evergy West's FAC?

A. The General Assembly allowed the Commission to include an incentive mechanism in the FACs it approved for the electric utilities. Section 386.266.1 RSMo. does not dictate the design of the incentive nor does it require the incentive to remain constant once established.[54] The 75/25 sharing mechanism that I have recommended is not a punishment but a balancing of the risk between Evergy West, that has the ability to lower the risk, and the customers who have no control. A 75/25 sharing mechanism provides an opportunity for Evergy West to recover a meaningful amount more than the costs when costs drop.

The Commission should recognize that this utility, by not acquiring generation and retiring generation without any resource that can provide the same electricity generating abilities, increased the risks associated with the volatile energy markets it is then dependent upon. Changing the sharing to 75/25, transfers some of that risk to Evergy West along with an opportunity for reward and puts less risk on customers who are at the whim of the energy market and the decisions of Evergy West's management to hedge, or in this case not hedge, that market.

CROSSROAD TRANSMISSION COSTS ARE STILL IMPRUDENT

Q. First, is it your understanding that Evergy West has changed its position regarding Crossroads costs in this case?

A. Yes. In her rebuttal testimony, Evergy West witness Linda J. Nunn, states:

> The Company agrees that the Crossroads transmission is not for purchased power or off-systems sales and should therefore be

[54] However, it cannot change between rate cases as the FAC can only change in a general rate proceeding. Section 386.266.5 RSMo.

> excluded from the FAC base calculation, but I do not agree that Crossroads should be excluded from recovery in base rates.[55]

Q. Do you agree with this new position?

A. No. Crossroads transmission costs are imprudent and should not be recovered from customers in base rates or through Evergy West's FAC.

Q. Mr. Ives asks the Commission to "acknowledge that the Company is the only party that has considered the current and future needs of EMW customers in formulating its analysis and recommendation for the treatment and recovery of Crossroads and its required transmission path prospectively."[56] Should the Commission make this acknowledgement?

A. Absolutely not. OPC is very aware of the need for capacity and energy for Evergy West's customers as Mr. Ives later admits in his rebuttal testimony.[57] Motivating Evergy West to meet the needs of its customers in a less risky manner than relying on the energy market is the driving reason for my testimonies in this case. In contrast, Mr. Ives is most interested in increasing the earnings of Evergy West at the detriment to Evergy West's customers.

Evergy West's renewed request for Crossroad's transmission costs demonstrates Evergy West's complete disregard for its customers; viewing the customers' only value as a never-ending source of more funds for Evergy management to use as it sees fit. Not only has Evergy West's management pushed the risk of market energy on its customers with the early retirement of Sibley without any generation to replace it, but now it is holding the capacity of an efficient peaking plant hostage. The required ransom: a Commission decision in this case to overturn previous Commissions' determination of imprudence resulting in the

[55] Page 3.
[56] Page 24.
[57] Page 29.

disallowance of transmission costs to the tune of over $16 million from Evergy West's customers.

If the Commission allows the cost recovery of the Crossroads transmission costs in revenue requirement, customers will be required to pay higher rates. If the Commission does not allow Evergy West to recover these costs from its customers, then Evergy West says that it will not renew the contract and build new generation. Table 4 shows all the various scenarios and the NPVRR as calculated by Evergy witness Cody VanderVelde.[58]

Table 4
Comparison of Net Present Value Revenue Requirement (NPVRR)

Scenarios	NPVRR (millions)	Change in NPVRR
Crossroads current treatment	$61.5	
Crossroads with Transmission	$281.2	$219.7
New CTs	$366.2	$304.7

All three provide capacity for Evergy West. The two options that Evergy West is presenting to the Commission, Crossroad's transmission or new CTs, will increase costs to customers by over $219 million and $304 million over the next twenty years respectively.

Mr. Ives is proposing to the Commission that including the transmission costs in revenue requirements is benevolent of Evergy West, *i.e.* the scenario with the $281.2 million increase in NPVRR is the best choice for its customers.

Q. What do you recommend to the Commission?

A. My recommendations in my direct and rebuttal testimonies have not changed. With respect to the Crossroads Energy Center costs:

1. The Commission should continue the rate base treatment of the Crossroads plant as ordered in case no. ER-2012-0175 and not include in revenue

[58] Evergy West direct workpaper "CONF_Crossroads Workpaper_VanderVelde."

requirement or the FAC any part of the cost of transmitting electricity from Crossroads to Evergy West's customers in Missouri;

2. The Commission remain silent regarding the renewal of Evergy West's contract with Entergy for firm transmission that allows the energy provided by Crossroads to reach the Southwest Power Pool ("SPP"); and
3. The Commission make it clear to Evergy West that it would be imprudent for Evergy West to remove Crossroads from service for customers and advise future Commissions to not allow the recovery of costs above what Evergy West would have incurred if Crossroads, without the cost of transmission, would have continued to be a generation asset for the rest of the life of the plant.

Given the information provided in Table 4 above provided in Evergy West direct workpapers, the PVRR of that imprudence amount would be approximately $304.7 million.

Q. Should the Commission recognize the important role Crossroads will play in its resource adequacy plans moving forward as requested by Mr. Ives?[59]

A. There is no need to specifically recognize Crossroads over any of Evergy West's other generation resources. By including a return on the net plant and a depreciation rate in revenue requirement, the Commission will recognize the appropriate value of Crossroads.

[59] *Id.*

Q. Should the Commission acknowledge as requested by Mr. Ives, that Evergy West's analysis demonstrating and supporting inclusion of Crossroads in its asset portfolio is the only analysis advanced in this proceeding on this topic and is unrefuted?[60]

A. The Commission should acknowledge Evergy West's analysis by using the analysis to warn Evergy West of the potential size of an imprudence adjustment if Evergy West chooses to not renew the transmission contract and builds CTs to replace Crossroads capacity.

Q. Are resource adequacy concerns new for Evergy West?

A. No. Aquila, the predecessor to Evergy West struggled for years to meet its capacity reserve requirement just as Evergy West is struggling now. The difference is that Aquila depended upon short- and long-term bilateral contracts for both capacity and energy that specified known costs for both the capacity and energy. Evergy West depends on bilateral contracts for capacity and the day ahead SPP energy market at an unknown cost for energy.

As I stated in my rebuttal testimony, Evergy West management is different people than the management team of Aquila but both teams have neglected the needs of the customers by not building generation to meet its customers' needs.[61]

Q. Is Crossroads any more important to Evergy West's customers now than it was in 2011 when the Commission first determined that it was imprudent for customers to have to pay for transmission from a plant in Mississippi?

A. No. Evergy needed generation resources to meet its reserve margin requirements in 2011 just as it does now.

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[60] *Id.*
[61] Page 8.

Q. Evergy West witness Cody VanderVelde argues that Crossroads transmission costs should be included in revenue requirement because Liberty's transmission costs for its Plum Point generation plant that is outside the SPP footprint is included in its revenue requirement. Is the Commission being inconsistent in including the transmission costs for Plum Point for cost recovery for Liberty and not Crossroads?

A. No.

Q. Would you explain why?

A. As I explained in my rebuttal testimony Evergy West's general rate case no. ER-2018-0145:

> **Q. At the end of his direct testimony for GMO, Mr. Rush testifies that the Commission has allowed The Empire District Electric Company to recover through its customer rates transmission costs related to its out-of-state Plum Point Power Plant generating asset as an example of where the Commission has allowed the recovery through rates of transmission costs for an out-of-state generating facility. What is your response?**
>
> A. Mr. Rush is correct that the Commission has allowed transmission costs for The Empire District Electric Company to receive energy from the Plum Point Power Plant ("Plum Point") in Arkansas. However, the circumstances there are vastly different than the circumstances here.
>
> Plum Point is a 720 MW supercritical, coal-fired, steam plant in Osceola, Arkansas, that became operational in 2010. It is located about 350 miles from Joplin. Empire owns 50 MW of Plum Point and has a long-term purchased-power agreement for another 50 MW. Empire's intention from the beginning when it joined in building Plum Point was to use the energy from the plant to serve its retail and wholesale customers. Empire expects to receive about ten percent of its customers' energy needs from Plum Point. Lastly, Empire does serve customers in the state of Arkansas.
>
> Crossroads is a natural gas combustion turbine facility that is over 500 miles from GMO's service territory. Aquila Merchant built Crossroads in a constrained location as a merchant plant to

> take advantage of a restructuring wholesale market. Aquila Merchant attempted to sell Crossroads in the early- to mid-2000's, but was unable to – even at a price below its book value. Before and after GMO acquired it, Crossroads was rarely used, and the Commission has stated in two previous general rate case orders that customers should not pay for the transmission costs of this plant. Nothing has changed that now makes it prudent for GMO's customers to pay these transmission costs.[62]

(Footnote omitted)

Nothing has changed since I wrote that testimony that now makes it prudent for Evergy West's customers to pay an even higher cost of transmission.

Q. Do you have a response to Mr. Ives assertion that the cost of Crossroads transmission will have reached $210 million by the end of the current transmission contracts?

A. In the Evergy West FAC prudence case no. EO-2019-0067, OPC argued that Evergy West imprudently entered into long-term purchased power agreements ("PPAs") with the Osborn and Rock Creek wind projects and at that point had cost the customers over $11 million more than the SPP revenues for the generation for the 18-month prudence period. Neither Evergy West nor Staff disagreed with OPC that these PPAs were costing customers more than the revenues they were receiving for energy generated.

In that case, Evergy West argued that even though these PPAs had not resulted in economic benefits as it projected they would, Evergy West was prudent in its resource planning decisions entering into these PPAs. The Commission agreed, stating in its *Report and Order*:

> The Commission will not replace the companies' primary supposition at the point of decision that the PPAs were being acquired in the context of a long term, twenty-year investment with

[62] Page 13.

> a supposition that the investment was short term, and then apply a hindsight test and pronounce the investments imprudent[].[63]

Evergy West's customers have paid and are paying the cost of a risk Evergy West took in entering into these costly PPAs. Customers will continue to pay that cost for the duration of these contracts even though Evergy West's analysis before entering into the contracts was wrong.

Similarly, the decision to transfer Crossroads ownership to Evergy West was a management decision.[64] Evergy took a risk when it made the decision to transfer Aquila's Crossroads plant to Evergy West. The Commission, not once but twice, declared the transmission costs to be imprudent. Now in hindsight, Evergy West is asking this Commission to declare the transmission costs prudent and require customers to foot the bill for a decision that Evergy made that has not worked out well for Evergy shareholders.

What is good for the goose should be good for the gander. The Commission should not require customers to pay Crossroads transmission costs just because it did not turn out like Evergy West management expected.

Q. Would you summarize your surrebuttal testimony regarding Crossroads transmission costs?

A. The inclusion of Crossroads transmission costs is not a "benefit" to customers because it is less than the cost of building to replace Crossroads capacity. Customers are paying for an Evergy West management decision to enter into wind PPAs that was not an economic decision for customers. Customers should not have to pay for an Evergy West management decision that is uneconomic for shareholders. Likewise, Evergy West's customers should not have to pay the cost

[63] Page 26.
[64] As documented in case no. ER 2010-0356 in the Commission's *Report and Order* (page 94), Great Plains Energy ("GPE"), the predecessor of Evergy, made the decision to transfer ownership of Crossroads to KCP&L – Greater Missouri Operations Company (GMO"), the predecessor of Evergy West, after due diligence.

that Evergy West may incur for additional capacity should it not renew the transmission contract.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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-2024-0189

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena M Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M Mantle

Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 9th day of September 2024.

TIFFANY HILDEBRAND
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES AUGUST 8, 2027
COLE COUNTY
COMMISSION #15637121

Tiffany Hildebrand

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2027.

Strategies for Encouraging Good Fuel-Cost Management

A Handbook for Utility Regulators

Report / July 2023

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Kaja Rebane, Jeremy Kalin, Albert Lin, Joe Daniel, and Rachel Gold, *Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators*, RMI, 2023, **https://rmi.org/insight/strategies-for-encouraging-good-fuel-cost-management/**.

Acknowledgments

The authors thank the following individuals for graciously offering their insights to this work and serving as advisors on this project. Inclusion on this list does not indicate endorsement of the report's findings.

- Travis Kavulla, NRG
- Mark LeBel, RAP
- Ron Lehr, independent consultant
- Annie Levenson-Falk, Minnesota CUB
- Janine Migden-Ostrander, Pace Energy and Climate Center
- Sonny Popowsky, Retired Consumer Advocate of PA
- Ted Thomas, Energize Strategies
- Frederick Weston, RAP

Energy Foundation provided funding to RMI to support this work. The findings presented in this work were independently authored by RMI, and RMI is solely responsible for the views expressed.

About RMI

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

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Executive Summary

Ensuring that rates are affordable and fair to customers is central to the mission of the regulatory commissions that oversee public utilities in the United States. Regulators operationalize this charge in many ways, from conducting detailed analyses of utility investment plans to carefully tailoring programs to the needs of low-income customers. However, in many jurisdictions little attention is paid to controlling fuel costs, which are a major factor driving recent increases in electricity bills.

Fuel costs represent a sizable portion of electric utility customers' bills, and fuel-price volatility can drive further bill increases with little notice. For example, in the wake of winter storm Uri in 2021, natural gas shortages caused prices to spike. Months later, regulators across the country were asked to approve utilities' requests to recover billions of dollars from customers to cover unexpected fuel costs.[1] Russia's 2022 invasion of Ukraine also caused coal and gas prices to increase dramatically.

The sustained high natural gas prices of 2022 drove the single largest year-on-year increase in electric bills.[2] The high energy bills are undoubtedly connected to the $16 billion in unpaid energy bills and massive increases in utility shutoffs in that time frame.[3] Those utility disconnections can have severe impacts, including potential eviction, loss of child custody, and even death.[4] Fortunately, utility regulators can do something to help avoid future harms to captive customers.

In most jurisdictions, fuel costs are handled through a regulatory mechanism known as a fuel adjustment clause (FAC).[i] Unlike most components of utility rates, a FAC enables the utility to recover exactly what it spent on fuel — so if the company manages to reduce its fuel costs, it retains none of the savings, and if it spends more than budgeted, its customers pick up the bill. This gives utilities that operate under FACs little incentive to manage their fuel costs carefully, and it gives regulators limited visibility into whether the utility spent more than was necessary.

However, FACs were not always the norm. Until the latter part of the 20th century, regulators typically handled fuel costs in the same fashion as most other components of utility rates. An estimate of expected fuel costs was built into the basic rates utilities charged for service (i.e., "base rates"), and the utility was expected to fund its fuel purchases with whatever amount it collected in this fashion. Unlike under a FAC, no ex-post true-up to the utility's actual expenditures was performed.

The status quo is already unaffordable for many people who struggle to pay their electric bills, and FAC policies that give utilities little incentive to manage fuel costs carefully are exacerbating this problem. Fortunately, FACs are ripe for revision due to technological advances and evolving markets. Vertically integrated electric utilities have more options than ever before to reduce their reliance on expensive and price-volatile fuels.[ii] These opportunities include switching to fuel-free generating resources, negotiating more favorable supply contracts, and taking steps to reduce the amount of fuel needed to meet customer

i In this handbook, the term FAC refers to all policies that enable utilities to collect what they actually spent on fuel from customers through an ex-post true-up. However, the names used to refer to these policies vary by state (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

ii Electric distribution companies in restructured states may also have opportunities to negotiate supply contracts and support demand-side management, but this handbook focuses on vertically integrated utilities.

needs (e.g., by working to conserve energy and shift demand). In contrast, customers have few strategies available to reduce fuel costs, so requiring them to continue bearing all fuel-price risk under FAC policies is increasingly unreasonable.

Fortunately, multiple regulatory strategies are available to reduce utility fuel costs. This handbook presents six reform options that regulators can use to encourage utilities to carefully manage their fuel costs and adopt cost-effective fuel-free resources. We also examine key questions related to each option and, where relevant, highlight examples of states that have already implemented these policies. The six reform options we discuss are:

- **Fuel-cost sharing.** This policy creates a financial incentive for the utility to carefully manage its fuel costs by requiring it to bear part of the risk of fuel-cost volatility. Under a typical fuel-cost sharing policy, the utility captures a share of the savings if it can reduce fuel costs below expected levels, and it also bears a share of any cost overruns. Fuel-cost sharing has already been implemented by a number of states, though the design details of these policies vary. For states adopting this option, we recommend the use of historical values or externally derived forward price indexes from public sources to avoid potential gaming risks. Regulators could elect to apply fuel-cost sharing to proposed new power plants, and they could have the utility lock in the price forecast used during plant approval as the amount utilities are allowed to recover from customers for fuel to run the plant over its lifetime.

- **Fuel-cost true-up removal.** This reform represents a return to the ratemaking approach that was standard before FACs became the norm. As under a FAC, an estimate of expected fuel costs is built into base rates — but unlike a FAC, no ex-post true-up is performed to match the funds recovered from customers to the utility's actual expenditures. Although no state has implemented this policy to replace a FAC, many precedents exist from the years before states adopted their FACs. This policy would shift the risk of fuel price volatility back onto utilities.

- **Fuel-risk reduction tariffs.** This strategy consists of implementing new retail tariffs that both create an incentive for the utility to reduce fuel costs and reduce participating customers' exposure to fuel-cost volatility. Such tariffs could be structured in various ways, such as by fixing the per-kilowatt-hour (kWh) rate used to recover fuel costs (and not truing it up afterward) or by offering customers a subscription-style tariff with a flat monthly charge. A number of states have implemented tariffs with this basic structure, though their motivation for doing so has not focused specifically on fuel costs.

- **Planning and procurement.** Many opportunities exist to reform resource planning and procurement in ways that encourage better fuel-cost management. These include updates to long-term planning processes, closer scrutiny of fuel-price projections, locking in forecasts for new generation, requiring all-source solicitation and procurement, the use of fuel management plans, and refinements to how utilities utilize hedging. Some states have implemented one or more of these policies to update planning and procurement.

- **Strategies to increase access to information.** It can be difficult for regulators to determine whether the fuel costs a utility presents for recovery through a FAC are unnecessarily high, so strategies that increase regulators' and stakeholders' access to information can encourage utilities to contain their fuel costs. These include making fuel-supply contract terms more transparent, utilizing enhanced prudence reviews, requiring regular audits, and facilitating broader and deeper stakeholder engagement in regulatory processes.

- **Efficiency ratio.** This is an emerging concept that regulators can consider, though it does not currently have a track record comparable to the other policy options. An efficiency ratio consists of a financial incentive tied to a production-cost-efficiency metric. In other words, it is a type of performance incentive mechanism (PIM) that encourages the utility to reduce the average cost of producing a megawatt-hour (MWh) of power.

These six policy options offer regulators a variety of possible strategies to reform existing FAC policies. Both utilities and the jurisdictions they operate in vary, so there is not likely to be a single "best" policy for every circumstance. The key questions we discuss in relation to each policy highlight some of the important design choices regulatory commissions are likely to face, and regulators may identify additional opportunities to tailor policies to local needs as reform discussions proceed. We encourage commissions to also consider the benefits of adopting more than one reform. For example, particularly strong synergies are likely to exist between strategies that increase access to information and the other policy options we discuss.

Given the impact that fuel has on both customer bills and the carbon emissions of electric utilities, we urge commissions to consider changing the way that utilities recover fuel costs from customers. Recent years have brought a raft of affordability challenges to states around the country, and we expect these trends to continue due to uncertain and volatile gas prices, the need to upgrade the grid to ensure resilience and replace aging distribution infrastructure, and required capacity expansions to accommodate the move toward electrification.

Because FAC policies give electric utilities little incentive to carefully manage their fuel costs, regulatory commissions should investigate and take action to reform these policies. This handbook is intended as a resource to support these important regulatory discussions.

Introduction

Fuel costs represent a sizable share of the total cost of producing electricity from power plants. These costs can also fluctuate substantially from month to month as fuel prices and quantities change. The magnitude and volatility of fuel costs make it imperative that utilities manage them carefully, but under typical ratemaking practices they have no financial incentive to do so. This is because of the widespread use of a policy known as the fuel adjustment clause (FAC).[iii]

FACs are rate riders that automatically true up the revenues collected from customers to match the utility's actual fuel expenditures.[iv] Although a utility's fuel costs are generally subject to a prudence review by its regulatory commission before they can be recovered, in practice the effectiveness of these reviews tends to be limited due to the information asymmetry between the utility and the regulator and the structure of the dockets wherein the prudence review occurs. Regulators often find it difficult to determine whether the receipts submitted by the utility were in fact the best use of customers' money. This is because regulators may not have good visibility into the effort the utility put into negotiating lower fuel prices, what fuel-free alternatives were available to the utility, and other factors. This often results in near-automatic approvals of requests for cost recovery and, as a consequence, little incentive for the utility to carefully manage its fuel costs.

This is problematic because the utility is the party best positioned to manage fuel-cost risk. Although fuel prices are not entirely under the utility's control, the company generally can negotiate more favorable fuel-supply contracts and take steps to reduce the amount of fuel needed to meet demand (e.g., by working to conserve energy, shift demand, or procure nonfuel alternatives). In contrast, customers have little ability to manage fuel-cost risk — yet FACs unfairly shift this risk entirely onto their shoulders. Vertically integrated utilities, which generate their own power to supply customers, are particularly able to manage fuel-cost risk by shifting their generation portfolios to fuel-free alternatives.[v] As a result, these utilities are the focus of this handbook, although some of the policy options we discuss may be relevant for other energy utilities as well.

FACs create a situation that economists refer to as "moral hazard," which exists when one party makes the decisions while another bears the risk of those decisions. By insulating the utility from the risks of poor fuel-cost management decisions — and also not rewarding the utility for making good decisions — a FAC gives it little incentive to work hard to reduce fuel costs. By transforming fuel costs from a major business expense to a side consideration, FACs enable poor fuel-cost management decisions that undermine affordability and perpetuate utility reliance on carbon-intensive fuel-based generation resources.

iii In this handbook, the term FAC refers to all such policies, but in some states they have different names (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

iv FACs are an example of what is known in regulatory parlance as a cost tracker. FACs are not the only type of cost tracker, but they (along with purchased-power cost trackers) are the most ubiquitous.

v Vertically integrated utilities are those that own generation, transmission, and distribution capacity, though most also purchase some power from other generators to meet customer demand. Electric distribution companies do not own generation yet they may also have opportunities to reduce fuel costs, such as by negotiating better supply contracts and supporting demand-side management. Though this handbook focuses on vertically integrated utilities, some of the policies discussed could be appropriate for electric distribution companies as well.

A FAC is typically implemented in several steps. First, the utility develops a forecast of future fuel costs, including estimates of both prices (e.g., $/million British thermal units) and quantities (e.g., the share of total demand that will be met by gas- or coal-fired generation). This forecast is then built into the rates that the utility can charge its customers for electric service — specifically, as part of the volumetric component (i.e., the per-kWh rate customers pay). After the rates take effect, the revenues collected through this rate component are compared with the utility's actual expenditures on fuel, and the cumulative difference is tracked over time via a balancing account.[vi] Periodically, the utility applies for the balance to be trued up by adjusting the FAC rider; the regulator considers the utility's application and approves the expenditures for recovery if they are deemed prudent (this usually happens in a dedicated fuel-cost recovery proceeding). Once the fuel costs are approved for recovery, the value of the FAC rider is adjusted to collect the additional revenue from customers (or to refund money if the utility collected more than it spent on fuel). The FAC rider typically appears as a separate line item on customer bills.

FACs are the norm today, but this was not always the case. Until the latter part of the 20th century, fuel costs were generally not given special treatment. Instead, they were handled in the same fashion as most other components of utility rates. Namely, the commission would approve a utility estimate of future fuel costs, which were then built into rates, and the utility could apply to raise its rates if the gap between the expected and actual fuel costs became too great. This approach established predictable per-kWh rates for customers and also rewarded the utility for limiting its actual fuel costs.

This changed in response to the fuel-price volatility caused by major geopolitical events during the previous century. In the wake of the two world wars, some utilities sought relief from exposure to fuel-price risk from their regulatory commissions and were granted temporary FACs. Then following the 1970s oil embargo, utilities across the country persuaded regulators to institute FACs with no sunset dates, and in some cases they even convinced legislators to write FAC policies into state statutes. As a result, FACs became the status quo nationwide.

However, the time has come to end the use of FACs for fuel-cost recovery. Due to an array of technological advances, utilities have more control than ever before over the amount they spend on fuel. Today, cost-effective solar and wind generation, battery storage, virtual power plants, and the managed charging of electric vehicles all provide new avenues to reduce reliance on fuels like natural gas and coal.

Retiring FAC policies could help motivate utilities to take full advantage of these new opportunities, which could reduce both customer costs and carbon emissions. This handbook presents six policy options that regulators can consider as alternatives to traditional FAC policies. We explore key questions regulators might consider in policy design, and, where relevant, we offer examples from US states with such policies.

vi In regulatory accounting terms, this variance is tracked over time through a regulatory asset (or regulatory liability).

Fuel-Cost Sharing

Fuel-cost sharing creates a financial incentive for the utility to carefully manage its fuel costs. Under a typical fuel-cost sharing mechanism, the utility can earn more if it reduces fuel costs and must bear a share of the burden if those costs rise. In other words, this reform exposes the utility to a portion of the fuel-cost volatility risk, so it is no longer fully insulated from fuel-cost changes as it is under a traditional FAC. Instead, under fuel-cost sharing the utility has some "skin in the game."

In fuel-cost sharing, an estimate of expected fuel costs is first built into rates, and then just part of the difference between the revenues collected and the utility's actual fuel expenditures is trued up. As is the case for a traditional FAC, this true-up is performed through a rider that applies an additional charge or credit to customer bills. The key difference between a traditional FAC and this policy option is that fuel-cost sharing trues up only part of the difference between the utility's *expected* and *actual* fuel costs.[vii]

Key Questions

Fuel-cost sharing can be implemented in a variety of ways. The most important questions that policymakers are likely to face include the following:[viii]

How should the expected value be set? Because fuel-cost sharing functions by truing up only part of the difference between the expected and actual fuel costs, an "expected" level of fuel costs must be determined by the regulator. This expected value can be based on either *forecasted* or *historical* values. Although forecasts are the most common approach used today by states that have adopted fuel-cost sharing, they can open the door to gaming. Specifically, if a forecast is used to set the expected value of fuel costs, the utility can benefit financially either by reducing fuel costs relative to the forecast or by inflating the forecast.

To avoid creating an incentive to inflate the forecast, regulators can instead base the expected value on historical fuel expenditures (e.g., a five-year rolling average of past fuel costs). If a forecast is used, regulators should consider using forward price indexes (e.g., NYMEX futures for natural gas are publicly available) rather than relying on the utility's bespoke modeling.[ix] Additional design decisions around the expected value will also need to be made. These include whether the forecast (or historical values) should be based on just the individual utility or a relevant peer group, whether a third party should be responsible for any tasks (e.g., developing the forecast), and what (if any) historical period of fuel expenditures should be considered.

vii Performing a true-up that brings the revenues collected in line with the actual costs incurred is often referred to as passing through these actual costs to customers. For example, a traditional FAC passes through 100% of the utility's actual fuel costs, whereas a fuel-cost sharing mechanism may pass through 90% of these costs. In this handbook, we do not use the term pass-through in this way, but readers may encounter it in other contexts.

viii For additional discussion of some of these questions, see Albert Lin, Jeremy Kalin, and Kaja Rebane, *Learning to Share: A Primer on Fuel-Cost Pass-Through Reform*, Pearl Street Station Finance Lab, 2023, **https://www.pssfinancelab.com/post/can-we-share-the-cost-of-fuel**.

ix Regulators should also ensure that any data source they use has sufficiently liquid trading to populate a credible sample, and that it includes buyers that are not rate-regulated utilities subject to this kind of cost-of-service regulation (e.g., industrial customers, merchant shippers). Where regulators face a choice between a less liquid trading point near the load the utility serves and a more liquid hub farther away, they may want to consider using the latter, subject to adding or subtracting a basis differential associated with observed pipeline rates or other clearly measurable factors.

How often should the expected value be updated? Although it may make sense to update the expected value at the time of a general rate case, a regulator could choose to reset it more frequently. For example, a special docket could be used to reset the expected fuel cost quarterly or annually, and that amount could then be recovered through a separate rider. However, updating the expected value too frequently could reduce the strength of the incentive created by the fuel-cost sharing mechanism. For instance, if the expected value is updated monthly, it may end up tracking actual fuel costs too closely, with the result that the mechanism functions similarly to a typical FAC.

How much sharing should occur? The amount of sharing should be high enough to motivate the utility to manage its fuel costs carefully, but low enough to avoid exposing the utility to unreasonable risk. Because utilities vary, there is not one universally "best" sharing amount. For example, sharing 5% of fuel costs (i.e., truing up 95% of the difference between expected and actual fuel costs) may be appropriate for a utility that is highly dependent on natural gas, whereas sharing 30% of fuel costs may be feasible for a utility with a less price-volatile resource mix (e.g., one that is high in coal or renewables).[x]

Should deadbands or other thresholds be used? The simplest approach to fuel-cost sharing is to apply the same sharing percentage regardless of how close or far actual fuel costs end up being from the expected value. This approach, which is sometimes called straight sharing, is most common among existing fuel-cost sharing policies. However, another option is to change the amount of sharing when this difference crosses a specific threshold. For example, a mechanism could feature no sharing if actual fuel costs are within a certain percentage of expected fuel costs — a design called a deadband. Alternatively, a mechanism could feature several bands with different sharing percentages (e.g., 20% sharing if actual fuel costs are within 5% of the expected value, 10% sharing if actual fuel costs are between 5% and 10% of that value, and 5% sharing if the difference is greater than 10%).

Deadbands and other thresholds have both potential benefits and drawbacks, which regulators should consider carefully during the design process. One potential benefit of a deadband, specifically, is that it can simplify policy administration. Outcomes that fall within the deadband do not require any adjustment to the fuel-cost rider that appears on customer bills, which reduces the need for prudence reviews and associated litigation. One drawback is that deadbands and other thresholds can create an uneven incentive structure for the utility. For instance, if the utility's share of fuel costs drops dramatically when a particular threshold is crossed (e.g., from 20% to 5%), the company may have little financial incentive to manage its fuel costs when it expects them to deviate from the expected value by more than that amount (such as during a period of high gas prices). Another drawback of complex banded structures is that they can be hard for customers to understand.

Should the mechanism be symmetrical or not? Another design question is whether the mechanism should operate differently depending on whether actual fuel costs end up being higher or lower than expected. Under a symmetrical mechanism, the financial rewards to the utility when fuel costs are lower than expected are a mirror image of the penalties to the utility when fuel costs are higher than expected. Under an asymmetrical mechanism, the rewards and penalties are structured differently. For example, a regulator could design an asymmetrical mechanism that trues up 95% of the deviation between expected and actual fuel costs when costs are lower than expected but just 85% when costs are higher than expected. In general, symmetrical mechanisms are viewed as more fair to the utility, create more consistent incentives for utility performance, and are easier for customers to understand than asymmetrical mechanisms. When the risk is asymmetrical, however, an asymmetrical sharing adjustment may be appropriate.

x Percentages presented here are for illustration purposes only. Regulators should conduct quantitative analysis looking at their utility's specific fuel mix to determine fuel-sharing percentages, as even two utilities in the same state might have different fuel mixes and therefore require different sharing percentages.

How should the true-up be conducted? The timing and duration of the true-up of expected to actual costs is another design consideration. As is the case with the true-up under a FAC, the true-up under fuel-cost sharing can be operationalized in different ways. For example, because positive and negative fluctuations in fuel costs tend to cancel each other out over time, performing true-ups every month or quarter will tend to result in more variable customer bills than performing them annually.[xi] Regulators concerned about rate shock may wish to perform less frequent true-ups, or to spread the cost recovery (or refund) needed to implement the true-up over a longer time period.

Should purchased power costs be included? Most vertically integrated utilities purchase some power from other parties, and they typically recover 100% of these purchased-power costs from customers via a true-up that operates much like a traditional FAC. Because generated and purchased power are substitutes, applying a sharing mechanism to one and not to the other may encourage gaming. For instance, the utility may purchase more power when fuel prices rise even if this is more costly for customers. Incorporating purchased power in the fuel-cost sharing mechanism can avoid this type of perverse outcome.[xii] Most fuel-cost sharing mechanisms today include purchased power or exist alongside mechanisms that track it.

Should sharing apply equally to all plants? Though fuel-cost sharing is typically implemented in the same fashion for all of a utility's fuel costs, this need not be the case. For example, a regulator that wants to focus the utility's attention on making better investment decisions going forward could apply a higher sharing percentage to new generating plants than to existing plants. If a commission were to apply fuel-cost sharing only to new plants, it could also lock in the fuel-price forecast used at the time of approval.

Should the amount of sharing increase over time? Once fuel-cost sharing is implemented, a utility can be expected to find ways to reduce its reliance on price-volatile fuels — and over time, the utility may be capable of managing a greater share of the remaining fuel-cost volatility risk. Recognizing this, a regulator may wish to ratchet up the sharing percentage over time to continue to create a strong incentive for the utility to improve further. Doing so on a forward-looking basis would give the utility better visibility into the timing and magnitude of future changes than would an ad-hoc approach.

Could fuel-cost sharing undermine electrification? The electrification of home heating, transportation, and other end uses will result in increased electric demand on the grid. Unless the new demand is met entirely by fuel-free generation, this will result in higher total fuel costs. Therefore, a fuel-cost sharing mechanism that penalizes the utility for higher-than-expected total fuel costs would tend to discourage it from supporting electrification. However, if used in concert with policies supportive of electrification, fuel-cost sharing instead could help create an incentive to meet the increased demand with new fuel-free resources (e.g., wind, solar) and to proactively manage new loads (e.g., electric vehicle charging) to shift usage away from high-cost hours.

Regulators could also address the potential impact of fuel-cost sharing on electrification more directly. One way could be to design the fuel-cost sharing mechanism with a carve-out for beneficial electrification. A second way could be to create a separate performance incentive mechanism (PIM) for beneficial

xi Performing true-ups annually also enables any normal seasonal variations in fuel costs to be netted out.

xii Exposing the utility to a share of fuel-cost risk could encourage it to shift its generation portfolio toward renewable resources, as these do not require fuel purchases. In this way, fuel-cost sharing could support state decarbonization goals. However, purchased power includes electricity generated from both fuel-fired and fuel-free resources, so purchased-power cost sharing would not be expected to drive decarbonization in the same way. Where reducing carbon emissions is an important policy goal, regulators could tailor the purchased-power sharing mechanism to support it. For example, the sharing mechanism could be designed in a way that distinguishes between different types of generation resources (e.g., it could apply a higher sharing percentage to fossil-fuel-fired resources than to renewables).

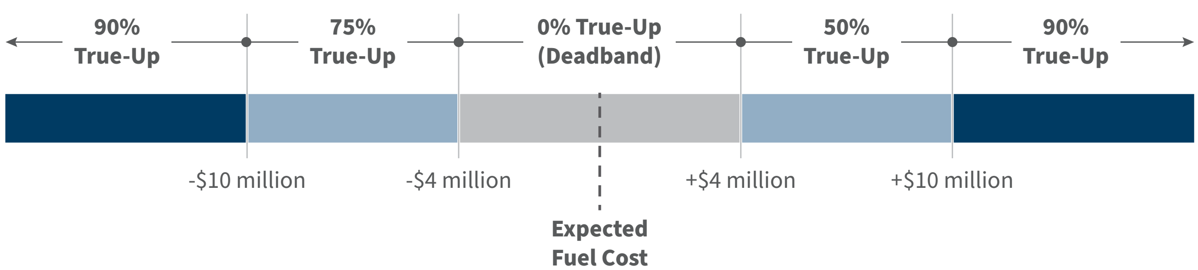
electrification that offsets the negative impact of the fuel-cost sharing mechanism.[xiii] A third possibility could be to structure the fuel-cost sharing mechanism to operate on a per-MWh basis rather than a total-cost basis, though this has the downside of creating an incentive to sell more electricity (i.e., a throughput incentive) whenever fuel prices dip below expected levels. We refer to such a mechanism as a type of "efficiency ratio"; for further discussion, see **page 27**.

State Examples

Wyoming is one state that has implemented fuel-cost sharing. Rocky Mountain Power's Energy Cost Adjustment Mechanism (ECAM) trues up the utility's actual net power costs (which include purchased power) to its forecasted costs in a symmetrical fashion.[5] The ECAM utilizes a straight-sharing approach. The mechanism previously shared 30% of fuel costs (i.e., the mechanism trued up 70% of the difference between expected and actual costs), but regulators subsequently updated the policy to share just 20% today.[xiv]

Washington has a fuel-cost sharing policy called the Power Cost Adjustment Mechanism (PCAM) for Pacific Power. The PCAM includes purchased power, relies on forecasts, and employs an asymmetrical banded design. The design features a deadband of $4 million on either side of the forecast within which no true-up is made. If actual costs exceed this amount, there are two sharing bands: within the first (up to $10 million), 50% of the difference is trued up; and within the second (over $10 million), 90% is trued up. If actual costs are less than expected, there are also two sharing bands: within the first (down to -$10 million), 75% of the difference is trued up; and within the second (less than -$10 million), 90% is trued up. This banded structure is illustrated in **Exhibit 1**. Under the current PCAM, the difference for a single year is recovered from customers over two years to reduce rate shock.[6]

Exhibit 1 **Banded Design of Pacific Power's Fuel-Cost Sharing Mechanism**



RMI Graphic. Source: RMI

xiii For example, if the utility's average fuel cost per kWh is $0.02 and the sharing percentage is 10%, the fuel-cost sharing mechanism would create a $0.002 penalty for every kWh of new load. A PIM that rewards the utility $0.002 per kWh of beneficial electrification would offset this penalty, and a PIM that offered more than this could create a financial incentive for the utility to pursue electrification.

xiv These sharing percentages can be found on Rocky Mountain Power's tariff sheets. For the present 80% true-up policy, see Rocky Mountain Power, *Schedule 95: Energy Cost Adjustment Mechanism*, Original Sheet No. 95-6, P.S.C. Wyoming No. 17, issued June 25, 2021. For the previous 70% true-up policy, see Rocky Mountain Power, *Schedule 95: Energy Cost Adjustment Mechanism*, First Revision of Amended Original Sheet No. 95-6, P.S.C. Wyoming No. 16, issued October 27, 2017. The utility's current tariff can be downloaded at **https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf**.

Oregon employs fuel-cost sharing subject to an earnings test. For example, Portland General Electric has an Annual Power Cost Variance Mechanism, which shares 10% of the difference between expected and actual costs (i.e., 90% of the difference is trued up) outside of a deadband. However, this occurs only if sharing does not cause the utility's earnings to deviate by more than 100 basis points from its commission-approved return on equity. The deadband is asymmetrical (no sharing occurs if actual costs are between $15 million less than forecast and $30 million more than forecast) and the mechanism includes purchased power.[7]

Missouri also has fuel-cost sharing mechanisms in place for Ameren, Evergy, and Liberty utilities. These mechanisms are all symmetrical, feature a straight-sharing design with a 5% sharing percentage (i.e., 95% of the difference between expected and actual costs is trued up), rely on forecasts, and include purchased power.[8] In a naming convention that may be confusing for those working in other states, these mechanisms are referred to as fuel adjustment clauses.[xv]

Hawaii uses a fuel-cost sharing mechanism for the Hawaiian Electric Companies (HECO).[9] The Energy Cost Recovery Clause (ECRC) takes a straight-sharing approach and employs forecasts to set the expected value that is built into rates. Under the mechanism, HECO trues up 98% of the difference between expected and actual fuel costs in a symmetrical fashion. The utility's annual financial exposure under the ECRC is capped at $2.5 million.

xv This differs from how we use this term in this handbook, in which we define a FAC as a mechanism that trues up 100% of the difference between expected and actual fuel costs.

Fuel-Cost True-Up Removal

Rather than reducing the extent to which expected fuel costs are trued up to actual fuel expenditures (as in fuel-cost sharing), the true-up can be eliminated entirely. This would mean that fuel costs would not receive special ratemaking treatment — they would simply be recovered in the same fashion as most utility costs.

Expecting utilities to fund their fuel expenditures without a rider may seem like a radical idea today, but this was standard practice until the mid-20th century. Removing the true-up would shift fuel-price volatility risk back to the utility, which is in a much better position to manage that risk than its customers. In other words, this policy option would restore the balance between utilities and customers that traditional ratemaking achieved. It would also give the utility a very strong incentive to seek ways to reduce its reliance on price-volatile fuels.

However, suddenly removing the true-up could create financial difficulties for a utility that has structured its current business model on the assumption that customers will bear all fuel-cost volatility risk. For example, if natural gas prices increase sharply and the utility relies heavily on gas generation, the impact on the utilities' financials could be drastic. Regulators interested in this reform should therefore proceed carefully and consider appropriate steps to protect the utility's financial health (e.g., by phasing out the true-up over time).

Implementing this reform can be mechanically simple — it only requires removal of the true-up step in a typical FAC. In other words, an estimate of expected fuel costs would be built into rates, but no ex-post true-up to actual expenditures would be made. The expected value to be included in rates would be determined as part of a regular rate case in the same fashion as other rate components, and it would not be updated further until rates are reset.[xvi] If fuel costs subsequently rise, the utility could cut costs elsewhere or come in for another rate case, and if fuel costs fall, the utility could enjoy additional profits.

Alternatively, a regulator could determine the expected value of fuel costs outside of a full rate case. For example, a special docket could be used to reset the expected fuel cost quarterly or annually, which could then be recovered as a separate rider. This approach could be particularly useful in jurisdictions that employ multiyear rate plans, where typically utilities are expected to stay out of rate cases for three to five years at a time.

xvi If a regulator expects fuel costs to vary seasonally, it could set a seasonal structure for the expected value rather than a single annual number. Automatic escalation based on an external index (e.g., inflation) could also be applied. We are not talking about such automatic adjustments when we refer to rates being "reset" here, but instead to the process of updating the estimate itself.

Key Questions

Some of the key questions that pertain to fuel-cost true-up removal include the following:

How should the expected value be set? As is true under a typical FAC, this policy option requires determining an “expected” level of fuel costs, which is then built into the volumetric component of rates. An important question is how this expected value will be determined and, in particular, whether it will be based on forecasted or historical values. The key drawback to relying on a forecast is that it can open the door to gaming because the utility would benefit financially if it can inflate the forecast. Setting the expected value based on historical data can help avoid this problem.[xvii] Another way to address this concern would be to use a publicly available commodity forecast (e.g., NYMEX for gas prices).

How often should the expected value be updated? Because this policy option removes the true-up of expected to actual fuel costs, it is important to update the expected value periodically to reflect changing conditions. If the expected value is set as part of a traditional rate case, it could be updated every one to two years along with other rate components. If the regulator opts to set the expected value in an alternative venue (e.g., a special fuel-cost docket), it could update the value as often as desired. Updates that are too frequent are likely to undermine the strength of the cost-containment incentive created by the mechanism, whereas updates that are too far apart could result in unacceptable windfall profits or losses to the utility. The regulator should carefully balance these factors when determining the cadence of updates.

How can the risk of extreme outcomes be reduced? Because actual fuel costs may sometimes be substantially higher or lower than expected when rates are set, a utility operating without a true-up may at times collect substantially more or less than what it spends on fuel. High windfall profits could undermine affordability for customers, whereas substantial losses could threaten the utility’s financial health. To avoid this, the regulator could adopt strategies to protect customers and the utility from extreme outcomes. For example, the regulator could specify particular conditions (e.g., utility profits that rise above a particular threshold) that would automatically trigger a review of the expected fuel-cost value.[xviii]

Would the utility cut key services if fuel prices spike? If the true-up is removed and fuel costs surge, a utility may cut costs elsewhere in an effort to hit its earnings targets. Although this concern is not unique to fuel costs, a large fuel-price spike could put substantial pressure on the utility to look for savings opportunities. This could lead to spending cuts in important but flexible spending categories like vegetation management, which could cause reliability problems down the road. Regulators could guard against such reactions by taking measures to reduce the risk of extreme outcomes, as discussed previously. They could also consider tracking or incentivizing utility performance in key dimensions that may be affected by spending reductions (e.g., reliability, customer service).

State Examples

At present, no state has removed the fuel-cost true-up. However, this policy was standard practice in every state before FACs became the norm.

xvii This gaming concern is also relevant to fuel-cost sharing, and we examined it in more depth in the section about that policy option. We encourage interested readers to review the more detailed discussion in that section.

xviii This is similar to the “reopener” provisions that are often included in multiyear rate plans.

Fuel-Risk Reduction Tariffs

Utilities could offer new retail tariff options that create an incentive for the utility to reduce fuel costs while simultaneously insulating customers from fuel-cost fluctuations. Such "fuel-risk reduction" tariffs would enable individual customers to avoid some of the risk of fuel-cost volatility. The strength of this incentive would depend on how many customers take service under the new tariffs, which would in turn depend on how many customer classes have access to it and whether it is implemented on an opt-in or opt-out basis.

Fuel-risk reduction tariffs would offer customers the opportunity to lock in a predetermined rate for the fuel-cost component of their bills. If the utility's actual fuel-cost expenditures differ from the revenues collected through these tariffs, the difference would not be trued up. In other words, if the utility paid more for fuel than it recovered from customers on the tariff, it would not recover that additional amount, and if it paid less, it would not refund the difference to customers.

Providing a fuel-risk reduction tariff as an option could increase customer choice. For example, such tariffs might appeal to customers who are concerned about volatility and willing to pay a potential premium for increased bill predictability.

Key Questions

The key questions for policymakers interested in developing a fuel-risk reduction tariff include the following:

How should the fuel-risk reduction tariff be structured? Tariffs that shift fuel-cost risk away from retail customers could be structured in different ways. One option is a *fixed-rate* tariff that features a set per-kWh rate for fuel costs. Because the revenues collected via this rate would not be subsequently adjusted to reflect the utility's actual fuel costs, such a tariff would expose the utility to more fuel-price risk than a traditional FAC. The set per-kWh rate could be time differentiated (e.g., it could differ by time of day or by season), but it would not be adjusted during the period when it is in effect. A fixed-rate tariff would operate similarly to the fuel-cost true-up removal policy option but on an individual customer basis.

Another option is a *flat-charge* tariff that features a monthly charge for fuel costs. Such a tariff could be implemented on a stand-alone basis, or it could be part of a broader subscription rate in which the customer's entire bill remains the same month to month. A flat-charge tariff could apply the same charge to all customers in a class, or the size of the charge could be based on past consumption levels (e.g., the average number of kWh consumed over the previous year). The second of these options is preferable.

Although applying the same flat charge to all customers would offer maximum predictability to the customer, this approach has some major downsides. Because customers would always pay the same amount regardless of how much electricity they use, they would have no financial incentive to conserve energy, install distributed generation, or shift demand in ways that benefit the grid. Because all of these actions can reduce total system costs, such a tariff could drive up costs for other customers in the short and long term (e.g., higher congestion charges during peak hours, more transmission and distribution system upgrades) and undermine state energy efficiency and emissions-reduction goals. Applying the same flat charge to all customers would also disproportionately benefit high-usage customers, who on average have higher incomes than low-usage customers. For all of these reasons, applying the same flat charge to all customers is not recommended.

A flat-charge tariff that is instead based on past consumption levels could partly address these issues. For example, if the average number of kWh consumed over the previous year is used to determine the size of the monthly charge, a customer who expects to remain on the tariff will have some incentive to conserve and to install distributed generation.[xix] Basing the size of the fixed charge on past consumption could also help avoid the subsidization of high-income customers by low-income customers.

Both the fixed-rate and flat-charge options would increase predictability for customers participating in the tariff, which means someone else must bear additional fuel-cost risk. This risk should not be placed on nonparticipating customers (e.g., by increasing the size of the FAC true-up on those customers' bills) because this could raise subsidization concerns and it would also undermine the utility's incentive to contain fuel costs. Instead, the utility should manage the additional risk. The customers participating in the tariff could also be asked to pay a risk premium; this would be incorporated into the tariff and would represent the price the customer must pay for increased predictability.

Should the tariff be opt-in or opt-out? Customer participation in opt-in tariffs tends to be much lower than in opt-out tariffs. Implementing a fuel-risk reduction tariff on an opt-in basis would enable individual customers to reduce their exposure to fuel-cost volatility, while likely keeping the overall financial risk to the utility low. In contrast, implementing the tariff on an opt-out basis would have much broader impacts on both customers and the utility.

How often should customers be allowed to opt in and out of the tariff? Whether the tariff is opt-in or opt-out, it could enable customers to bet on fuel-cost trends, opting in if they think prices will increase and opting out if they think prices will decrease. The risk of such behavior is likely to be greatest among large commercial and industrial customers, but this strategy could be used by any savvy customer. To reduce this risk, regulators could limit how often customers can opt in and out of the tariff.

Which customer classes should be included? The fuel-risk reduction tariff could be offered to a small subset of customers or more broadly. Such tariffs may be of particular interest to those who value stability (e.g., commercial customers), though if customers must pay a premium for that stability, they may be less appropriate for some customer segments (e.g., low-income residential customers). Regulators should also consider whether some customers will need help understanding whether the new tariff makes sense for them, making customer outreach and education necessary.

How should the preset rate or charge for fuel be determined? The per-kWh rate or flat charge for fuel costs can be based on either a forecast or historical values. As with fuel-cost sharing and fuel-cost true-up removal, relying on forecasts could open the door to gaming because if a utility is able to inflate the forecast, the rate and thus collected revenues will increase. Relying on historical values instead (e.g., a five-year rolling average of past fuel costs) can help avoid this problem.

xix The incentive to conserve would be somewhat less under this tariff design than under a fixed-rate tariff because the financial benefit to the customer of saving a kWh would be delayed by up to a year. The incentive to install customer-owned distributed generation would also be somewhat less because customers would still need to pay the upfront cost of the system but would not realize any savings on their bill for some time. Such a tariff could, however, encourage customers who are planning to electrify their home to adopt energy efficiency retrofits the year before, as this would lock in a lower flat charge for their first year of increased consumption due to electrification.

How often should the rate or charge be updated? As fuel costs change over time, the per-kWh rate or flat charge should be changed periodically to reflect updated expectations. These updates could be conducted only through a general rate case (and thus occur on the same schedule as the updates to most other rate components) or they could be performed more frequently through a dedicated proceeding. Less frequent updates could give more certainty to customers enrolled in the tariff about the size of future bills. However, if updates are too infrequent, the tariff could collect more or less revenue than necessary over an extended period, resulting in large windfall gains to the utility (which could undermine affordability) or large losses (which could negatively impact the utility's cash flow). The best schedule for updating the tariff will depend on local factors, such as the utility's fuel mix, the share of customers enrolled in the tariff, and the existing rate-case schedule. Regulators could also put guardrails in place that trigger a review if actual fuel costs deviate sharply enough from expected values.

Would a fuel-risk reduction tariff affect electrification? A fuel-risk reduction tariff would not penalize the utility for greater total fuel usage (as some other policy options discussed in this handbook would), so it would not create a financial incentive for the utility to oppose electrification. On the customer side, a tariff that applies the same flat charge to all customers regardless of usage could even encourage electrification, but there are more efficient, equitable, and direct ways to accomplish this policy goal.[xx]

State Examples

A number of utilities offer flat-charge-style tariffs. While these may include other cost components besides fuel expenses, they can offer models to regulators interested in designing fuel-risk reduction tariffs.

Oklahoma Gas & Electric (OG&E) is one example. It offers a "guaranteed flat bill" to its residential and small general service customers that features a fixed monthly charge over the course of a year. The level of the charge is based on the individual customer's weather normalized historical usage over 12 to 24 months, as well as an adjustment for expected usage changes over the period. The formula used to calculate the level of the charge includes a risk premium, the impact of which is capped at 10%. If actual usage exceeds expected usage by at least 30% over three months, the utility has the ability to move the customer off the tariff and charge them an early departure fee.[10] In 2021, OG&E experienced a loss from its guaranteed flat bill tariff when winter storm Uri drove up natural gas prices.[11]

Florida Power & Light (FP&L) also offers a flat-charge tariff to residential and small general service customers. Its FLAT-1 tariff consists of a fixed monthly charge for a period of one year, the size of which is based on the customer's historical consumption normalized for weather and adjusted for changes in customer behavior. The calculation includes a risk premium capped at 5%. FP&L can require a deposit up to twice the estimated average monthly bill to move a customer onto the tariff, and the utility can move the customer off the tariff and charge a removal fee if their consumption exceeds expectations by 30% for three months.[12]

xx As discussed previously, applying the same fixed charge to all customers would diminish customers' financial incentive to conserve electricity. This would encourage customers to electrify but not in an efficient manner, which could unnecessarily drive up overall system costs. Also, not all customers would be equally positioned to act on a tariff-based electrification incentive. For instance, renters may not have the power to make upgrades to their residences, and low-income customers may not have the ability to purchase electric vehicles. Other types of programs (e.g., rebates for building owners, electrification of public transit) may be more effective electrification strategies than retail tariffs for these customers.

Duke Energy Indiana offers a flat-charge tariff to a limited number of residential customers with load profiles that "can be modeled with reasonable predictability." The size of the monthly charge under the Your FixedBill tariff is calculated based on 12 or more months of past usage data, normalized for weather, and subject to a usage adjustment (this adder is capped at 3.6% for the first year the customer is on the tariff and 0.8% after that). The formula used to calculate the charge can include a risk premium (called a program fee) of up to 9%. Duke can send letters warning the customer of excess usage, and if after two such letters the customer's usage is 15% greater than expected for any month, the utility can reprice the monthly charge based on updated usage information. If the customer does not accept the new amount they are removed from the Your FixedBill tariff and charged a $50 administration fee.[13]

In states that have opened the electricity market to retail competition, various fixed-rate plans are available to customers. These could also serve as examples for fuel-risk reduction tariffs adopted for regulated utilities that feature a fixed-rate design.

Planning and Procurement

A variety of updates to planning and procurement processes could help reduce utilities' reliance on costly and price-volatile fuels. Updating long-term planning and procurement methods can reduce utility reliance on fuels over time (and thus the need to recover fuel costs from customers). Shorter-term strategies, meanwhile, can focus utility attention on careful fuel-cost management and limit the impact of fuel-price volatility on customer bills. A number of key reforms that regulators could consider are explored below.

Long-term planning. Changes to long-term resource planning requirements can play a large role in shifting the utility's portfolio away from price-volatile fuels over time. Such reforms can take a variety of shapes. Many, but not all, states conduct resource planning, though there is plenty of room for improvement in how those resource plans are conducted, reviewed, and approved.[14]

Regulators could direct the utility to fully consider cost-effective demand-side resources (e.g., energy efficiency, demand flexibility) during portfolio creation and to treat them as supply-side resources rather than as reductions in demand during modeling. Regulators could also mandate the inclusion of specific portfolio types (e.g., fuel-free portfolios) in the utility's analysis, and they could require more robust analysis of fuel-price volatility in the utility's resource plans. Regulators could also empower stakeholders to scrutinize the utility's modeling choices and propose their own portfolios, such as by requiring the utility to run new models based on stakeholder-provided inputs or requiring the company to make its modeling data, assumptions, and software available to stakeholders.[xxi]

Scrutiny of fuel-price projections. Regulators should also change how price-volatile fuels like natural gas are considered during the planning process. This could be accomplished through increased scrutiny of gas-price forecasts and their underlying assumptions and by requiring the utility to run high gas-price sensitivities for all portfolios. Commissions should also direct utilities to conduct more sophisticated analyses (e.g., stochastic analyses) to reveal potential cost impacts under a variety of converging conditions (e.g., fuel-price spikes, heat waves, supply disruptions).

Regulators should also ensure that the fuel-price forecasts used across proceedings are consistent. A utility should not be permitted to use a low gas-price forecast when planning new generation resources and a higher forecast to set the expected value for a fuel-cost sharing mechanism. As another example of how the fuel-cost assumptions used in planning could be improved, regulators could require that new fuel-related infrastructure proposals (e.g., gas-fired plants and pipelines) be presented with realistic service lives that are in line with state climate goals. For example, regulators could choose not to permit a utility to propose a 30-year lifetime for a new gas plant in a state with a zero-by-2050 policy goal.

xxi For example, one expert recommends that the utility provide: (1) the entire modeling database in a format readable without a model license; (2) a well-documented manual detailing the logic of the model, defining the inputs and outputs, and providing guidance on its use; and (3) the ability to license the model at a reasonable cost if a license is not otherwise provided by the utility. See William Driscoll, "States Could Save Consumers Billions with Solar, by Requiring Transparent Utility Modeling," *PV Magazine*, September 9, 2019, **https://pv-magazine-usa.com/2019/09/09/states-could-save-consumers-billions-with-solar-by-requiring-transparent-utility-modeling/**.

Locking in forecasts for new generation. If a utility expects to bear some of the financial risk of fuel-cost volatility, it will be inclined to do the most robust possible planning to account for the price volatility of fuels. Regulators can build a reasonable level of risk exposure into the planning process by requiring that all new generation be subject to fuel-cost sharing. Commissions could also consider locking in the price forecast used at the time of approval as the baseline (i.e., the expected value) used by the fuel-cost sharing mechanism.[xxii]

All-source solicitation and procurement. Long-term planning is often based on resource-specific assumptions, and then the resources selected are procured as a separate step later. The resource-selection process is highly sensitive to the input assumptions, so if those assumptions are unrealistic (e.g., fuel prices that are too low) or limited (e.g., distributed resources are not considered), this can create a bias toward selecting traditional, fuel-based resources.[15] Procurement processes can also favor traditional solutions when they invite bids for specific resources rather than system needs. Updating these processes can result in increased selection of fuel-free generation and demand-side resources.

Regulators should mandate the use of all-source solicitation and procurement as a means of removing the bias against fuel-free resources. All-source solicitation and procurement involves defining the utility's needs (e.g., energy, capacity, flexibility services) and then inviting bids for any technologies that can meet those needs. The submitted bids can be used to represent the options available during the planning process, and they can also serve as the basis for subsequent procurement decisions.[16] To ensure all proposals can compete fairly, the fuel-price risk associated with different resources should be carefully considered when selecting between them.[17]

Fuel management plans. Fuel management plans encourage utilities to focus more on fuel-cost management, and they also better position regulators to determine whether the fuel costs that utilities later present for recovery were prudently incurred. These plans can require the utility to articulate its fuel procurement plans, predict fuel-cost outcomes under different possible scenarios (e.g., severe weather events, supply-chain disruptions), and explain its risk management strategies. To ensure that plans are of high quality, they should be subject to regulatory review and approval. Moreover, plan sponsors should be subject to discovery and cross-examination, and stakeholders should have opportunities to review and provide input on plans through filed comments, public hearings, and responsive testimony.

Hedging. Hedging refers to the use of financial instruments to mitigate risk. Used by utilities to reduce the impact of fuel-price volatility on customer bills, hedging can be thought of like insurance where premiums are paid to prevent high-price outcomes. When done correctly, hedging can provide stability and savings, but if done improperly, it can result in unnecessary costs. Some hedging arrangements require a monthly or annual fee in exchange for a cap on prices. Others lock in a predetermined price and amount of fuel to be purchased at a future date, which insulates the off-taker from market price volatility. Many utilities use hedging to some extent, but in many jurisdictions it is subject to little or no review.

Regulators interested in reforming hedging should review current practices and consider whether any changes are needed to better serve customer interests. However, many commissions do not have staff with sufficient experience or expertise in hedging to fully examine the risks and benefits of particular hedging agreements. In those cases, oversight of hedging practices could be folded into the fuel management plans described above.

xxii This idea was also discussed in relation to the fuel-cost sharing policy option, on **page 12**.

Key Questions

Given the variety of possible updates to planning and procurement processes, the questions regulators face will depend on the reforms they are considering. However, they may include the following:

How should utility bids be treated during all-source solicitation and procurement? To obtain the best outcomes, all-source solicitation and procurement processes should create a level playing field for all proposals. However, if the utility is responsible for choosing between bids, it may favor its own submissions (or those of its affiliates) over the bids of third parties. Regulators can prevent this by not allowing the utility (or its affiliates) to submit bids, or if they do allow the utility to submit proposals, they can take steps to ensure that all proposals are fairly evaluated.[18] One way to accomplish that would be to require the use of both an independent consultant to draft the request for proposals (with no input from any utility division that could submit a bid) and an independent evaluator to assess the proposals received.

Is hedging worth the additional cost? Like any insurance, hedging needs to be used carefully to cost-effectively protect against volatile fuel prices. Hedging is not guaranteed to be cost-effective, and it could be imprudently procured. Evaluating fuel hedging through independent audits and regularly reviewing the performance of hedging instruments are key.

Should resource and system planning processes be coordinated? Because long-term resource planning focuses on the resources that will be needed to meet demand, reforming these processes represents a key opportunity to reduce utility reliance on costly and price-volatile fuels. However, the physical configuration of the transmission and distribution system also matters because this determines which fuel-free resources can actually be used and how much flexibility there is to substitute between them. Closer coordination between resource planning and system planning processes can enable better optimization of the overall system to enable demand to be reliably and affordably met with less fuel.

State Examples

Various states have planning and procurement policies in place that can serve as examples for other regulators. For example, **Indiana** requires utilities to evaluate demand-side resources “on a consistent and comparable basis” with supply-side resources during the planning process, including consideration of the resources’ risk and cost-effectiveness.[19] In **New Mexico**, when regulators granted stakeholders access to utility modeling, they enabled stakeholders to propose alternative resource portfolios to replace a retiring coal plant. The result was that the commission adopted an entirely fuel-free portfolio identified by stakeholders, rather than the option preferred by Public Service Company of New Mexico (which had included new natural gas-fired generation).[20] Meanwhile, the use of all-source solicitation and procurement in **Colorado** produced third-party bids with what Public Service Company of Colorado described as “shockingly” low wind and solar prices.[21]

Strategies to Increase Access to Information

A central reason why traditional FACs create suboptimal outcomes concerns access to information. Utilities generally have better access to information than their regulators do, and because of this "information asymmetry," it can be difficult for regulators to determine whether the fuel costs presented for recovery through a FAC are unnecessarily high. For example, the regulator may not be able to tell if a utility is using its better contracts to supply competitive markets and dumping its inferior ones on customers.

Strategies to improve information access can support sound fuel-cost management in multiple ways. Where another fuel-cost reform has been implemented, greater access to information can help the regulator understand how well that policy is working and whether additional changes are merited. Strategies that improve information access can also be beneficial on their own because they can help regulators better administer the FAC policies that remain in place in most of the United States.

A variety of strategies could enhance regulators' and stakeholders' access to information. Four of the most promising in relation to fuel costs are discussed below.

More transparent fuel-supply contract terms. In many states today, utilities are allowed to treat their fuel-supply contracts as trade secrets, which prevents customers and other stakeholders from evaluating whether they are reasonable. When advocates and other stakeholders are barred from accessing key documents, they cannot identify potential prudence issues and flag them for the commission to consider. Regulators could increase transparency by requiring utilities to publicly disclose the key terms of these contracts (e.g., minimum delivery amounts, automatic pricing adjustments, changes in the scope of utility and vendor responsibilities).

Enhanced prudence reviews. In many states, fuel-cost recovery proceedings are limited in scope and subject to tight timelines. As a result, fuel costs are often approved for recovery after only a superficial prudence review. Regulators could reform these proceedings to enable enhanced scrutiny. Regulators can strengthen the minimum filing requirements to shift the burden of proof onto the utility requesting cost recovery, while simultaneously demonstrating a willingness to disallow recovery if the utility cannot convincingly demonstrate prudence. For this strategy to be effective, it must be be clear to the utility that disallowance is a real and substantive risk. Simply applying a slightly higher level of review to an existing, cursory process is unlikely to be successful.

Regular audits. Audits by an independent third party can give regulators, customers, and stakeholders better visibility into a utility's performance, including its fuel-cost management, fuel procurement practices, and risk-reduction strategies. Requiring both a management audit and a financial audit on an annual basis would be beneficial.

The financial audit provides insight into how the utility has been spending money. This audit would enable both the regulator and stakeholders to better judge whether its fuel purchases have been prudent.

The management audit may be a substantially longer document. It could include detailed information across multiple dimensions (e.g., how much natural gas is purchased through short-term versus long-term contracts, the origins of purchased coal, contract terms and conditions). It can also include auditor recommendations (e.g., that the utility take specific steps to ensure gas plants remain operational during cold weather, that the utility purchase more power through power-purchase agreements to reduce uneconomic fuel purchases). The management audit can enable stakeholders to access important information without the need for lengthy discovery processes, and the auditor's recommendations can shape regulatory decisions.

Regulators should require the sponsors of audits to be subject to discovery and cross-examination in relevant dockets. Audit parameters should also be clearly defined to provide clarity in priority areas of performance and to enable comparison with industry peers.

Broader and deeper stakeholder engagement. Robust stakeholder engagement in proceedings where fuel-cost recovery is considered can help regulators access and analyze the information they need to make sound decisions. Where commission staff have limited capacity to dig into utility fuel-cost filings, stakeholders can help identify inconsistencies and potential prudence concerns. Enabling stakeholders to offer their own proposals for changes (rather than being limited to reacting to utility proposals) can also help surface new solutions. Finally, stakeholder responses in dockets that point out issues related to fuel-cost recovery can help build a library of information that other stakeholders and regulators (both within and outside the state) can later use to improve policies.

Strategies to enhance stakeholder engagement include restructuring proceedings to allow more time for stakeholders to provide input, ensuring ample opportunities for discovery and cross-examination, and equipping stakeholders with the resources they need to engage meaningfully (e.g., automatic access to key information such as via management audits, intervenor compensation to enable less well-resourced stakeholders to participate). Regulators could also solicit input from previously underrepresented constituencies and increase the participatory nature of commission processes (e.g., informal solution-finding workshops in addition to formal litigated processes).

Key Questions

The key questions regulators will face depend on which strategies they choose to pursue to increase information access. However, such questions will likely include the following:

Will additional effort be required from regulators and stakeholders? As with any reform, the amount of effort that a reform will demand is important to consider. Enhanced prudence reviews are likely to increase the demands on regulators and their staff, who may already be heavily burdened by existing work. In addition, strengthening stakeholder engagement could require devoting regulatory resources to educating parties who are not familiar with existing policies or processes. However, there are often multiple ways to accomplish the same goal, and regulators can consider whether there are alternatives that reduce the needed effort. The time that commission staff and stakeholders must devote to discovery requests can be reduced by using regular financial and management audits, as well as by requiring the utility to automatically disclose key data, models, and documents during enhanced prudence reviews.

Will additional time be needed to reach decisions? Some strategies to increase access to information may require additional time. Enhanced prudence reviews may take longer than current prudence reviews, and establishing robust stakeholder engagement in a fuel-cost recovery proceeding may require comment periods to be lengthened, public hearings to be added, or outreach to be conducted to specific constituencies. If additional time is needed, regulators should consider how processes can be changed to accommodate this. For example, conducting fuel-cost recovery proceedings less frequently could offset the increased time it takes for an enhanced prudence review during each proceeding.

How should sensitive information be handled? Though greater disclosure of utility fuel-supply contract terms, data, models, and other information could be beneficial, some information is sensitive and should be disclosed selectively. Regulators should consider whether any part of a fuel-supply contract should remain confidential, and if so, a nondisclosure agreement should be required for stakeholders to access it. Utilities may wish to keep certain data as a trade secret so it cannot be accessed by competitors, but regulators should consider whether this is appropriate for a utility that functions as a regulated monopoly (and which therefore does not face direct competition).

What will be the cost to customers? Some strategies to increase information access involve costs that are ultimately born by customers. Audits require substantial time and effort from both the third parties conducting them and the utilities subject to them, while achieving robust stakeholder engagement may require that intervenor compensation be provided to less well-resourced parties. As with any reform, it is the regulator's responsibility to determine whether the incremental costs of a reform outweigh the benefits the reform is likely to provide.

State Examples

A number of states have policies that support increased access to information. One is **Kentucky**, which requires utilities to file copies of all fuel-supply contracts (including any modifications and related documents) promptly, to justify in writing any purchases from utility-controlled sources, and to also justify any price-escalation clauses. Kentucky then makes all these documents available for public inspection.[22]

Ohio regulators recently required independent performance audits of extra customer charges that were collected by three utilities buying power from coal-fired power plants (often at above-market prices), and regulators then solicited stakeholder comments on the auditors' findings.[23]

Minnesota also requires utilities to submit an independent auditor's report every year evaluating the previous year's automatic fuel-cost adjustments, though regulators' ability to choose not to approve the auditor's report is limited.[24]

States also have taken steps to broaden and deepen stakeholder engagement.[xxiii] In a recent distribution system planning proceeding, **Oregon** conducted stakeholder education, structured the proceeding in ways that facilitated stakeholder input, and provided less formal venues (e.g., workshops) for engagement. In **Michigan**, the MI Power Grid initiative has engaged hundreds of diverse stakeholders through more than 50 meetings, including representatives of local communities, environmental justice organizations, and consumer advocates. Also, **at least 16 states** offer intervenor compensation to support stakeholders' ability to engage in regulatory proceedings.[xxiv]

xxiii For more information about all the state examples discussed in this paragraph, see Cory Felder, Jessie Ciulla, Rachel Gold, and Jacob Becker, *Regulatory Process Design for Decarbonization, Equity, and Innovation*, RMI, 2022, **https://rmi.org/insight/puc-modernization-issue-briefs/**.

xxiv These 16 states are Alaska, California, Colorado, Hawaii, Idaho, Illinois, Kansas, Maine, Michigan, Minnesota, New Hampshire, Oregon, Tennessee, Washington, West Virginia, and Wisconsin.

Efficiency Ratio

As detailed previously, reforms designed to share fuel-cost risk between utilities and their customers is an emerging policy space in which most US states have limited experience. We anticipate that decision makers will develop a range of new policy proposals in the coming years as fuel-cost volatility, advances in fuel-free technologies and demand management strategies, and continued social inequities push them to reevaluate the wisdom of existing FAC policies.

One such emerging idea is implementing a PIM to encourage the utility to reduce the cost of producing a MWh of power. A PIM is a regulatory tool that ties a portion of a utility's earnings to a desired outcome, which is measured by a specific metric. In this case, the metric is the utility's production cost efficiency measured in $/MWh, so we refer to this type of PIM as an "efficiency ratio." The $/MWh metric could focus narrowly on the utility's own fuel expenditures, or it could include purchased power and represent the utility's net power costs.

To be effective, an efficiency ratio PIM must not only measure the utility's production cost efficiency today but also indicate whether the metric has improved or declined over time. To accomplish this, the historical value of the metric (e.g., the utility's historical per-MWh fuel costs) is compared with the metric's current value. If the utility's $/MWh has decreased, its production cost efficiency has improved and the company would be eligible for a financial incentive under the mechanism. Conversely, if the $/MWh has increased, its production cost efficiency has declined and the company may be subject to a penalty.

The financial reward or penalty under a PIM can be structured in various ways. An efficiency ratio is no exception; while by definition an efficiency ratio must employ a $/MWh metric, regulators have the flexibility to select from a range of possible incentive structures. These possibilities include a constant marginal incentive (e.g., the utility earns the same reward for each incremental improvement in the metric), a lump sum (e.g., the utility earns a fixed reward if its performance exceeds a specific threshold), and more complex designs (e.g., a banded design in which the marginal or lump-sum incentive changes multiple times as the utility's performance crosses different thresholds).

Another possibility is to use the $/MWh metric to implement a usage-normalized version of fuel-cost sharing. In this approach, the improvement (or decline) in the value of the $/MWh metric would be multiplied by the total MWh from a reference period. For example, using the MWh expected under "normal" weather conditions as the multiplier would result in a weather normalization. Under this PIM, if the actual weather conditions were "normal" over the time period, the financial impact on the utility would be the same as a fuel-cost sharing policy — but if a heat wave caused usage to skyrocket, the utility would not be penalized for the resulting increase in fuel costs.

In addition to the structure of the financial incentive, regulators must also consider its magnitude. Ideally the incentive should be large enough to motivate the utility to achieve the policy goal, but no larger since excessive rewards unnecessarily burden customers and excessive penalties could negatively impact the utility's financial health. If both financial incentives and penalties are used, the commission must also consider whether these should be symmetrical or asymmetrical.

Regulators could design the efficiency ratio to apply to all power generated by the utility (i.e., a single $/MWh metric could be used) or separately to different categories of power (e.g., the $/MWh could be tracked and incentivized separately by fuel type). Regulators may also wish to apply the efficiency ratio to purchased power to avoid encouraging the utility to make uneconomic substitutions between purchases and its own generation (e.g., generating more electricity when fuel prices fall even if power could be purchased from third parties more cheaply).

Regulators should also consider how different factors may impact the $/MWh metric. For instance, although an improvement in the metric may reflect improvements in the utility's fuel-cost management, such improvement could also be due to factors outside the utility's control (e.g., general market conditions) or utility actions that run counter to policy goals (e.g., running an aging coal plant more to decrease the heat rate, reduce the $/MWh, and earn a larger reward under a coal-specific efficiency ratio). Commissions may therefore wish to apply additional tests that require the utility to show that any $/MWh reductions were the result of its own appropriate actions before allowing it to receive an incentive payment. Regulators could also consider adjusting penalties if the utility can convincingly demonstrate that a deterioration in the metric was due to no fault of its own.

Potential Benefits and Drawbacks

As a new policy option, the key benefits and drawbacks associated with the efficiency ratio are still emerging. However, the following considerations may be relevant.

One benefit is that if the $/MWh metric is restricted to the utility's own fuel costs, it is straightforward to calculate. Since all vertically integrated, investor-owned utilities report historical data on fuel costs and generation to federal agencies (e.g., the Energy Information Administration, the Environmental Protection Agency), there is no need for fuel-cost forecasting. However, if additional costs are included in the metric (e.g., the fuel costs in purchased power, other variable operating expenses deemed part of the net power cost), these data may not be as readily available, and in some cases they may require estimation.

Furthermore, utilities may be more supportive of the idea of an efficiency ratio PIM than other policy options. Thus far, the efficiency metric concept has sparked greater engagement from utilities in states considering action by commissions or legislatures.[xxv]

xxv This is based on informal conversations that some of the authors have had about fuel-cost management options with state legislators, commissioners, consumer advocates, and utility representatives.

However, the efficiency ratio concept also has certain drawbacks. One is that focusing on $/MWh may not advance other policy objectives. A utility could reduce the $/MWh ratio by either reducing the numerator (cost) or increasing the denominator (electricity production). However, tactics to increase the total electricity production may not be in the public interest.[xxvi] For instance, a utility could "improve" the $/MWh metric by declining to pursue opportunities to conserve energy during hours when costs are below average.[xxvii] The effects of this drawback are limited somewhat by the fact that in the next period the lower $/MWh value becomes the new benchmark.

An efficiency ratio applied separately to different categories of power (e.g., one that tracks the $/MWh by fuel type) could create additional challenges. For instance, if the PIM rewards the utility for reducing its per-MWh cost of generating power from natural gas, a drop in natural gas prices could enable the utility to earn a reward for each additional MWh it can generate from that fuel — even if this means curtailing more cost-effective resources (e.g., wind, solar). This could result in both higher costs to customers and higher carbon emissions. An efficiency ratio applied separately to different categories of power could also create an incentive to run coal units at higher capacity factors to increase plant efficiency (i.e., to decrease the heat rate), something entirely within the utilities' control.

Further Development

As the efficiency ratio is an emerging idea, its benefits and drawbacks have not been fully explored. As with any novel policy, regulators interested in this concept should investigate its potential impacts carefully. The design and implementation of any efficiency ratio should also include robust engagement with utilities, consumer advocates, trade associations, and other relevant stakeholders.

xxvi A financial incentive to sell more electricity is called a throughput incentive. Since a throughput incentive tends to undermine utility support for energy efficiency programs, many states have taken steps to combat the throughput incentive created by traditional ratemaking. Such policy actions include revenue decoupling and PIMs focused on energy efficiency programs. Regulators in states that have energy efficiency as a policy goal may wish to consider whether additional actions are merited to address any throughput incentive created by an efficiency ratio.

xxvii If a utility's per-MWh costs are substantially higher in a few hours of the day or year, most hours of the year may in fact fall into the "below-average cost" category. For example, in the late afternoon a certain utility may need to bring more costly gas plants online to meet its daily peak — and its per-MWh cost may rise further during a few hot summer afternoons when air conditioning usage is peaking, wholesale electricity prices are spiking, and the utility must purchase additional power to meet its customers' needs. A few very costly hours can push the average $/MWh well above the median, with the result that the majority of hours have costs that are below average.

Conclusion

The traditional FAC policies that are common across the United States give electric utilities little incentive to carefully manage their fuel costs. Under a FAC, customers, rather than the utility, pay for excessive fuel expenditures, and if the utility reduces its fuel costs, it does not benefit. Given the impact that fuel has on both customer bills and carbon emissions, it is worth considering alternatives to the traditional FAC.

When the wisdom of FACs is called into question, utilities often defend these policies by arguing that they have no control over fuel costs. However, this was never entirely the case, and it is even less true today. Thanks to technological advances, utilities are in a better position to manage their fuel costs now than ever before. This is true on both the supply side (e.g., cost-effective renewables, battery storage) and on the demand side (e.g., time-of-use rates, virtual power plants).

Because of these developments, considering alternatives to traditional FACs is particularly timely — and we encourage regulators to explore the options available to them. This handbook is intended as a resource to support these discussions.

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LEARNING TO SHARE: A PRIMER ON FUEL-COST PASS-THROUGH REFORM

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Acknowledgements:

This report was made possible by the generous support of Energy Foundation.

We would like to thank Rachel Gold (RMI) and Joe Daniel (RMI) for their thoughtful review of this work and Liza Martin (Independent Contractor) for editing expertise.

Organizational affiliations are listed for identification purposes only. The opinions expressed herein do not necessarily reflect those of the organizations that funded the work or the individuals who reviewed it. Pearl Street Station Finance Lab bears sole responsibility for the report's content.

April 4, 2023

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Executive Summary

Electric utilities in the United States spend billions of dollars annually buying fuel to generate electricity. These costs often make up a sizable share of customer bills, and unlike other bill components, they can vary substantially from month to month. This makes it imperative that utilities manage their spending on fuels carefully—but most utilities have no financial incentive to do so. This is because in most states today, utilities are allowed to pass on 100 percent of their actual spending to customers through policies called "fuel adjustment clauses" (FACs).

FACs create a problem that economists call "moral hazard." Moral hazard exists when one party does not suffer the consequences of making bad decisions, so it takes bigger risks as a result. Current 100 percent pass-through policies create moral hazard because if utilities manage to reduce fuel costs (for example, by negotiating better prices or reducing their fleet's reliance on fuel) their customers receive all of the benefits, and if utilities manage their costs poorly, their customers pick up the bill.

Ever since FACs were implemented, they have created this moral hazard problem. However, in recent decades its real-world consequences have grown more acute due to a series of developments. These include several trends which have magnified the risks of heavily relying on price-volatile fuels for electricity generation, and others which have decreased the cost of fuel-free alternatives. In addition to the heavy cost burden that FACs impose on today's customers, they also fail to incent utilities to aggressively pursue clean resources that could help lower carbon emissions.

Though FACs are the norm today, these policies are ripe for revision by legislators and public utility commissioners interested in addressing these growing challenges. However, not all policy makers understand the downsides of current FAC policies, and not all those who do are motivated to take proactive actions to address them. Advocates can play important roles in educating key policymakers, encouraging them to act, and enlisting the support of other parties when needed to advance reforms in their state.

Eliminating FACs altogether may seem like the simplest policy fix, but moving from a 100 percent pass-through to a zero-percent pass-through overnight could create financial difficulties for utility companies. Fortunately, such an abrupt change is not necessary. Updating the FAC to pass through a lower share of the utility's actual spending to customers can successfully address the moral hazard problem while limiting the total risk the utility is exposed to. This type of reform is called "fuel-cost sharing."

Fuel-cost sharing can be implemented in different ways. The basic fuel-cost sharing policy that has been adopted by most states to date represents only a modest departure from the status quo. It entails first building a forecast of fuel costs into the utility's base rates (as is true of FAC policies), and then truing up less than 100 percent of the difference between the forecasted and actual spending. However, this is not necessarily the optimal design, since relying on forecasts makes this approach vulnerable to gaming by the utility. FAC reforms can also be designed in other ways that may better serve local policy priorities.

A range of design considerations are relevant. These include the extent of fuel-cost sharing, whether the sharing is symmetrical, and which costs are included in the mechanism. Other policies can also

be used to complement the fuel-cost sharing mechanism or serve as alternatives to it, including reforms that increase transparency, encourage hedging, and increase the scrutiny of utility spending decisions.

While FAC policies remain the norm across the United States today, a few states have adopted fuel-cost sharing policies or other reforms. These include Hawaii, Idaho, Organ, Wyoming, Montana, Washington, Wisconsin, Vermont, and others.

Reforming FAC policies could enhance affordability by motivating utilities to manage their fuel costs more carefully. It could also reduce carbon emissions by encouraging utilities to switch more quickly to fuel-free technologies. It is time for these outdated policies to change, and both commissions and advocates can play important roles in advancing reforms.

Introduction

Every year in the United States, electric utilities spend billions of dollars purchasing fuel to generate electricity. During the COVID-19 pandemic, between 2020 and 2021, vertically integrated utility companies alone spent $70 billion in fuel costs.[1] This represents a sizable share of the total cost of producing electricity.

However, thanks to an obscure policy commonly known as the "fuel adjustment clause" (FAC), most US utilities lack any financial incentive to reduce how much money they pay for fuel.[2] Instead, these utilities are allowed to "pass through" 100 percent of these costs to their customers via a bill rider. Customers then have little choice but to pay for these costs—since the alternative would be to lose their access to electricity. In many states, the FAC is a specific line item on electric utility bills, as illustrated in Figure 1.

Figure 1. Sample Electric Bill from Xcel Energy

ELECTRICITY CHARGES	RATE: Net Energy Billing Svc		
DESCRIPTION	USAGE UNITS	RATE	CHARGE
Basic Service Chg			$8.00
Basic Service Chg			$1.90
Energy Charge Winter	946 kWh	$0.088030	$83.28
Energy Charge Winter	0 kWh	- $0.121590	$0.00
Fuel Cost Charge	946 kWh	$0.035507	$33.59
Sales True Up	946 kWh	- $0.007360	- $6.96 CR
Affordability Chrg			$0.98
Resource Adjustment			$14.23
Interim Rate Adj			$8.14
Subtotal			**$143.16**
City Fees		5.00%	$7.06
Transit Improvement Tax		0.50%	$0.74
City Tax		0.50%	$0.74
County Tax		0.15%	$0.23
State Tax		6.875%	$10.20
Total			**$162.13**
Premises Total			**$162.13**

A FAC often appears as a separate line item on customer electricity bills. It is highlighted on this residential bill from Minnesota.

The burden on customers is further increased by the variability of fuel costs. Unlike most components of utility bills, the size of the fuel charge fluctuates substantially over time. This is largely due to the volatility of natural gas prices (and to a lesser extent, coal prices) coupled with changing weather. For example, in January 2022, fuel-cost volatility combined with Kentucky

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1 Lin, Albert, J. Daniel. "Electricity Customers are Getting Burnt by Soaring Fossil Fuel Prices. RMI. June 2023. www.rmi.org/electricity-customers-are-getting-burnt-by-soaring-fossil-fuel-prices/

2 Fuel costs are passed through to customers via FACs by both electric utilities and natural gas utilities. While this primer focuses specifically on electric utilities, many of the same arguments for FAC reform apply to gas utilities as well. We refer to policies that pass 100% of fuel costs through to customers via a bill rider as "fuel adjustment clauses" (FACs), but in some states these policies go by different names (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

Power's FAC resulted in roller coaster" rates that made it difficult for some customers to make ends meet.[3] Figure 2 illustrates the volatile nature of natural gas prices over the last decade.

Figure 2. Historical 30-day price volatility of natural gas

Natural gas prices are highly volatile. Though the price spike in early 2022 was particularly severe, gas prices continually rise and fall in unpredictable ways.[4]

Though FACs pass through 100 percent of actual costs to customers, most components of utility rates do not work this way. The basic rates utilities charge customers for electric service (known as base rates) are set in advance according to the projected costs of power generation and delivery over a set period of time. These base rates establish a predictable per-kWh rate, even if utilities spend more or less than was expected when the rates were set.

In contrast, a FAC allows a utility to charge customers for the exact amount spent on fuel. As a result, fuel does not represent a business cost or profit center for utility companies. This means utilities are able to ignore the cost and volatility of fossil fuels in their decisions, even though customers end up paying more as a result.

> "Because of this 100 percent pass-through policy, a utility that manages its fuel costs well earns no reward—and one that manages them poorly faces no consequences because its customers pick up the bill."

Allowing utilities to ignore the consequences of relying on fuels distorts decision-making about what types of resources to invest in, which can disadvantage fuel-free resources in utility planning and investment decisions. Since earnings are not affected if fuel prices rise, the utility can ignore the risk of volatile and elevated costs when making investment decisions. Ignoring the volatility of fossil fuels

[3] Emily Bennett, WSAZ Investigates: Kentucky Power bill spike, January 28, 2022, https://www.wsaz.com/2022/01/28/wsaz-investigates-kentucky-power-bill-spike

tips the scales towards them—and away from more cost-effective fuel-free alternatives like wind, solar, and energy efficiency. FACs also give utilities no incentive to find shorter-term strategies to lower fuel costs, such as negotiating better fuel-supply contracts.

This phenomenon differs from what happens in a competitive market, where a company that succeeds in reducing its costs will gain an advantage over its competitors. A regulated utility with a FAC gains nothing if it succeeds in reducing its fuel costs. Because of this 100 percent pass-through policy, a utility that manages its fuel costs well earns no reward—and one that manages them poorly faces no consequences because its customers pick up the bill.

History of Fuel-Cost Pass-Through Policies

Fuel costs were not always treated as a 100 percent pass-through to utility customers. For almost the whole first century of US utility regulation, utilities were expected to manage their fuel costs in the same fashion as other business expenses.

The first power plants were built in the last few decades of the 19th century. To prevent privately owned utilities from overcharging customers, local and state governments stepped in to regulate the rates they could charge. The newly created public utility commissions treated fuel costs as just one aspect of the costs of doing business, rather than as a unique cost category requiring special ratemaking treatment.[5]

When World War I caused fuel prices to soar, utilities lobbied commissions for relief from fuel-price volatility and the associated risk of significant financial loss. Public utility commissions responded by implementing the first temporary FACs, which they discontinued shortly after the war. When World War II also created global fossil-fuel supply challenges, commissions reinstituted temporary FACs—which were likewise curtailed once peacetime resumed.

The oil shocks of the 1970s again sparked utility demands for insulation from global supply disruptions, and this time both state legislators and public utility commissions responded. Though the gasoline lines of the 1970s soon disappeared, in most states the statutes and commission decisions that established FACs have never been meaningfully revisited.

Today, these policies are the norm across the country. In most states, the process through which costs are approved for recovery through FACs is opaque to customers and their advocates, since investor-owned utilities are allowed to treat their fuel-supply agreements as trade secrets. This means that despite being saddled with 100 percent of the costs, ratepayers cannot generally evaluate whether the fuel-supply agreement terms are reasonable.

It is reasonable to wonder why legislators and public utility commissions have left these policies in place for so long. FACs are typically justified based on the idea that utilities cannot control the cost of fuel. However, this assertion was never entirely true, and it is even less true today. For example, utilities make decisions about how much natural gas capacity to build, and they negotiate the fuel-supply contracts that determine the prices they pay for natural gas. In addition, due to technological

5 We refer to all such regulatory bodies as "public utility commissions." In many states the body has a similar name (e.g., the Nevada Public Utilities Commission), but this is not always the case (e.g., the Maryland Public Service Commission, the Kansas Corporation Commission, the Washington Utilities and Transportation Commission).

advances, utilities can now displace fuel-based generation with a range of cost-competitive alternatives that use little to no fuel (e.g., solar, wind, batteries, energy efficiency). Yet, because FACs insulate utilities from the financial consequences of relying on fuel, the companies have little incentive to change.

The Problem: Moral Hazard and Inefficient Investment Decisions

FACs create a problem that economists call "moral hazard." Moral hazard exists when one party does not suffer the consequences of making bad decisions, so they may take bigger risks as a result. The moral hazard problem crops up in many spheres, including insurance, investing—and utility regulation.[6]

> "The moral hazard problem has existed since the first FACs were implemented; however, in recent decades the real-world consequences of this have grown more acute."

In the regulatory sphere, 100 percent fuel-cost pass-through policies provide a particularly stark example of moral hazard. When a FAC is in place, the utility decides how much fuel to buy and at what price—but it is the utility's customers who pay the cost if the utility spends more money than necessary. In other words, the utility (and its shareholders) are held harmless from the consequences of poor fuel-management decisions.

The moral hazard problem has existed since the first FACs were implemented; however, in recent decades, the real-world consequences of this have grown more acute. This is due to two types of recent trends. First, a series of developments have magnified the risks of relying heavily on fuels. Second, the costs of fuel-free alternatives have decreased.

Trends that Have Magnified the Risks of Relying Heavily on Fuels

The first category is developments that have increased the risks associated with relying on fuels. These include the following:

> **Greater utility dependence on natural gas.** Over the last two decades, utilities have been building gas-fired power plants at a rapid pace. Because of this construction spree, the share of electricity generated from gas has risen dramatically (Figure 3), and electric utilities have grown from being small, niche buyers of natural gas to being the gas industry's biggest market (Figure 4). This has created a situation in which customers are much more exposed to the effects of gas-price volatility than they used to be. Natural gas prices are by their nature volatile, and now a much higher share of electricity generation depends on gas purchases.[7] In addition, the electric sector's demand tends to rise and fall in a pattern driven by seasonal changes and regional weather events—which can cause supply constraints. For

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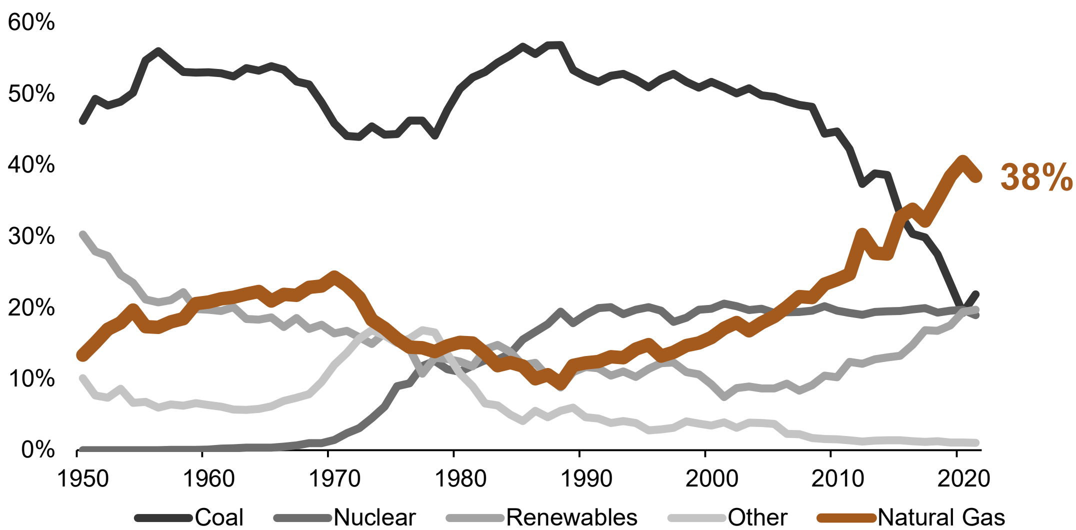
[6] The classic insurance example is that an insured party may take more risks than they would otherwise, since the insurer will pay for any loss that may occur. An example from the world of investing is that a money manager may take excessive risks with other people's wealth.

[7] Jamison Cocklin, U.S. Natural Gas Price Volatility at All-Time High in 2022, Natural Gas Intelligence, August 16, 2022, https://www.naturalgasintel.com/u-s-natural-gas-price-volatility-at-all-time-high-in-2022

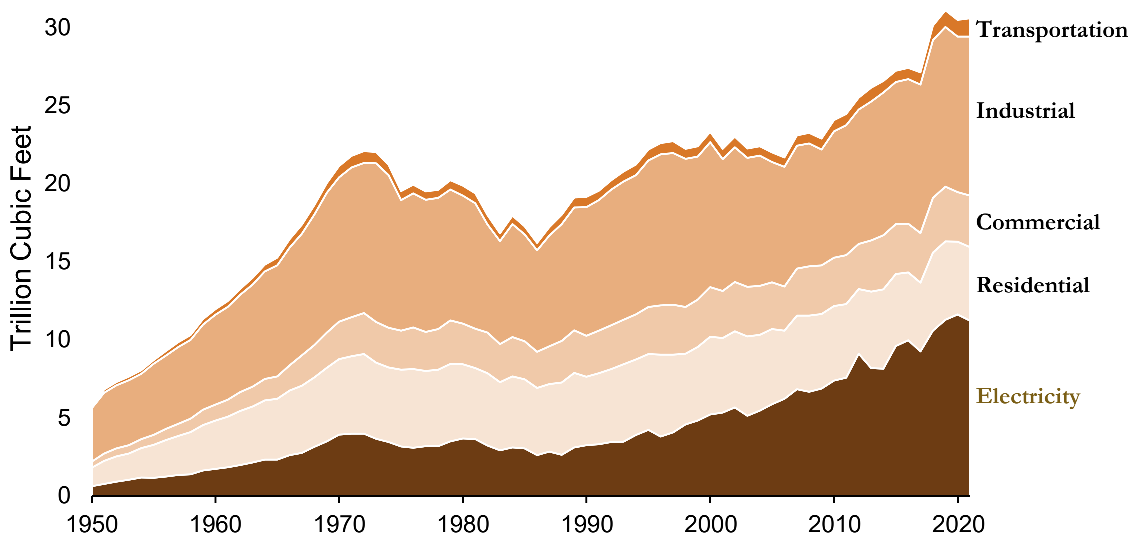
example, if a major heat wave hits the eastern United States, the electric utilities in all impacted states will consume more natural gas than usual to meet the increased need for air conditioning, resulting in rapid price increases as regional gas inventories are depleted.

Figure 3. US Electricity Generation by Resource



Between 1950 and 2022, the share of electricity generated from natural gas roughly tripled, from 13 percent to 38 percent.[8]

Figure 4. US Natural Gas Consumption by Sector



In recent years, the electric power sector has become the largest customer of the natural gas industry.[9]

More severe weather. Another recent trend is that weather is becoming more severe due to climate change. The growing intensity of both summer heat waves and winter cold snaps

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increases the odds of large fuel-price spikes as gas demand outstrips available supply. For example, in 2021, Winter Storm Uri led to a steep drop in natural gas production, leading to supply constraints and record-setting prices.[10] Forest fires, hurricanes, and other severe weather events can also trigger fuel-supply disruptions.

Increasing exposure to geopolitical risks. Globalization has made the international economy increasingly interconnected. With heightened natural gas prices in Asia and Europe, US producers ship a sizable share of domestically produced gas abroad as liquified natural gas (LNG)—and the United States recently became the world's largest LNG exporter.[11] This heavy involvement in international trade makes the US natural gas sector vulnerable to conflict-induced supply disruptions, which can translate into increased fuel-price volatility. For example, when Russia invaded Ukraine in February of 2022, the combination of sanctions against Russian gas and increased exports to Europe caused global prices to soar.[12]

Trends that Have Made Fuel-Free Alternatives More Attractive

In addition to the trends magnifying the risks of relying heavily on fuels for electricity generation, a series of developments have made fuel-free alternatives more reliable and cost-effective. These include the following:

Cheaper fuel-free alternatives. Through the end of the twentieth century, most commercially viable generation technologies (e.g., coal, natural gas, nuclear) required fuel. Today, fuel-free energy resources like energy efficiency, solar, and wind are often the lowest-cost sources of power,[13] while new technologies like advanced metering infrastructure (AMI) and distributed energy resource management systems (DERMS) can enable storage, energy efficiency, and demand response to be deployed in ways that allow a much higher share of demand to be met by these resources.[14] Utilities today can choose to reduce fuel dependence in ways that were not possible even a few years ago.

Supportive federal policies. The Inflation Reduction Act (IRA), passed in 2022, featured a range of provisions that increased the economic attractiveness of fuel-free alternatives. These include the extension of the production tax credit (PTC) and investment tax credit (ITC) that are available to renewable and storage facilities, changes that better position regulated utilities to take advantage of these tax credits, and access to low-cost debt to help retire existing fossil-fired power plants.[15]

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[10] American Public Power Association, Winter Storm Uri, Extreme Winter Events, And Natural Gas Reforms, Issue Brief, January 2022, https://www.publicpower.org/system/files/documents/January%202022%20-%20Winter%20Storm%20Uri.pdf

[11] EIA, The United States became the world's largest LNG exporter in the first half of 2022, July 25, 2022,

[12] IEA, Russia's War on Ukraine: Analysing the impacts of Russia's invasion of Ukraine on global energy markets and international energy security, https://www.iea.org/topics/russias-war-on-ukraine

[13] Zachary Shahan, Wind & Solar Are Cheaper Than Everything, Lazard Reports, CleanTechnica, November 15, 2020, https://cleantechnica.com/2020/11/15/wind-solar-are-cheaper-than-everything-lazard-reports

[14] Lauren Schwisberg, The Business Case for New Gas Is Shrinking, RMI, December 8, 2022, https://rmi.org/business-case-for-new-gas-is-shrinking

[15] Jessie Ciulla, Gennelle Wilson, and Rachel Gold, What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service, RMI, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira

The Consequences of Moral Hazard Have Grown More Acute

Taken together, these recent trends have fundamentally changed the US energy landscape. The risks of overreliance on fuel-based generation have increased while fuel-free alternatives have become more reliable and cost effective. In this new world, it literally pays to reduce utilities' reliance on fuel.

However, when a FAC is in place it's not the utilities who receive this benefit—it's customers. While a utility doesn't profit from using more fuel, it doesn't profit from decreasing fuel usage either. It's also important to realize that managing fuel costs carefully isn't free. It takes managerial effort and investment in expertise, and utility managers are incentivized to focus on other areas of operations and investment. Because of this, utilities are not taking full advantage of current opportunities to reduce fuel costs. Fortunately, a practical solution to this moral hazard problem is available. We turn to this next.

A Promising Solution: Fuel-Cost Sharing

FACs are the norm today, but this can be changed. These outdated policies are ripe for revision by legislators and public utility commissioners who care about making utility services more affordable, protecting customers from unnecessary risks, and/or reducing carbon emissions. The moral hazard created by 100 percent pass-through policies undermines all of these goals—so updating these policies can yield multiple benefits.

Since FACs have only been the norm for a few decades, it may seem like the best solution would be to eliminate them altogether. However, such a marked departure from current practice could pose significant risks. Today's utilities would be more sensitive to unexpected fuel-cost fluctuations than their early 20th-century counterparts, since current business models have developed based on the expectation that utilities will be sheltered from this source of volatility.[16] For this reason, suddenly moving from a 100 percent passthrough to a zero-percent pass-through policy could undermine a utility's financial stability, driving up its cost of capital and eventually necessitating rate hikes.[17]

Fortunately, states do not need to shift 100 percent of the fuel-cost risk back onto the utility. The goal of reforming the FAC is simply to motivate the utility to keep its fuel costs in check—and this can be done while limiting the total risk the utility is exposed to.

This reform can be accomplished by updating the FAC to only pass through part of the fuel costs to customers. This does not mean that customers wouldn't pay anything for the rest—just that they would reimburse the utility for the rest of the fuel in the same way they pay for most utility expenditures. In other words, these costs would be recovered in rates that are set in advance and not trued up afterwards to match actual expenditures. This reform is called "fuel-cost sharing," though in reality what it does is share the risk that fuel costs will deviate from expectations between the utility and its customers.

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[16] The relevant features of current utility business models include but are not limited to their capital structure, organizational structure, and risk profile.

[17] A utility's cost of capital is the minimum amount the utility would need to pay debt and equity investors to secure the funds it needs to run its business. This is sometimes referred to the utility's "true" cost of capital to distinguish it from the estimated cost of capital regulators use when setting rates, which is generally higher than the true cost of capital.

Fuel-cost sharing can be implemented in different ways—and we discuss key design options later. However, at this point it would be helpful to understand the basic mechanics of the form that has been most often adopted by states thus far.

This form of fuel-cost sharing requires only a modest departure from the way most FACs are implemented today. Under the typical 100 percent pass-through policy, a forecast of fuel costs is first built into base rates and the FAC then trues up the forecast once the actual expenditure has been made. The FAC does this by charging or crediting customers for the difference between the forecasted and actual fuel costs via a rider; this usually appears as a separate line item on customer bills. The only change to this status-quo policy that is made to implement the reform is to true up less than 100 percent of this difference.

For example, a fuel-cost sharing policy of this type could true up just 90 percent of the gap between the forecasted and actual fuel costs. This would mean that if fuel costs are less than forecast the utility will get to keep 10 percent of the underspend, and if fuel costs exceed the forecast it will bear 10 percent of the excess amount. In other words, the utility will now have a financial incentive to seek ways to reduce fuel costs—and customers will receive 90 percent of any savings.

While this is the variant of fuel-cost sharing that has been most widely adopted to date, it is not necessarily the optimal one. One of its biggest drawbacks is that if the utility is able to inflate the fuel-cost forecast that is built into base rates, it will be able to retain a share of that inflated amount (e.g., 10 percent in our example). In other words, anchoring the fuel-cost sharing mechanism to a forecast can invite the utility to game the forecast.

Fortunately, there are ways to avoid this problem, and there are also more complex structures that can allow regulators to tailor their fuel-cost sharing policy to local circumstances. We will discuss these policy design options later.

Avenues for Reform

It is one thing to identify a needed reform—and a different thing entirely to make it happen. The most fruitful strategy will vary by state, and it may also vary by utility.

To identify appropriate reforms, it is important to first understand how fuel costs are currently regulated. The biggest question is whether 100 percent of fuel costs are passed through to customers or if there is some form of fuel-cost sharing already in place. Keep in mind that 100 percent fuel-pass-through mechanisms are sometimes called different names, even though we refer to them all as FACs here.

The next step is to determine which decision makers have the ability to reform the existing policy. Public utility commissions are responsible for overseeing regulated utilities and setting the prices they can charge, so achieving FAC reform will likely require engaging with the commission. However, some state legislatures have passed laws that mandate 100 percent pass-through policies, so, in these states, reform will require revising these statutes. In addition, interested legislatures can motivate reform at the commission by encouraging or requiring it to revisit these policies.

How to Engage a Public Utility Commission on Fuel Adjustment Clause Reform

To engage a public utility commission on the topic of FAC reform, advocates first need to identify the best formal venue.

Commissions make decisions through individual proceedings (aka "dockets") that focus on particular regulatory issues. Each proceeding is assigned a specific identifying number (often called a "docket number"), and the documents associated with the proceeding can generally be obtained through a commission's online docket search.[18] Participating in a proceeding typically requires applying for intervenor status, but sometimes the commission will issue a notice inviting comments from the general public.[19] The types of proceedings that may be good venues for FAC reform include the following:

> **Dedicated FAC dockets.** Commissions typically periodically review and approve fuel costs for recovery in specific FAC-related dockets, so engaging in these proceedings can be one way to push for changes. However, in some states, these proceedings offer little opportunity to scrutinize utility requests for fuel-cost recovery—for example, where stakeholders lack access to key data, face rapid turn-around times for comment submission, are constrained by a narrow definition of the issues in scope for the proceeding, or face other barriers that prevent them from advocating effectively for reform. In these cases, pushing for changes to the way the commission conducts these dockets may be a prerequisite to reforming a FAC through them.
>
> **Rate cases.** General rate cases may also provide a venue for stakeholders to raise concerns about fuel-cost treatment and offer solutions. The basic function of rate cases is to set the utility's base rates going forward, and to do this the commission examines a wide array of different topics that pertain to utility expenditures. Rate cases are typically conducted over a longer time frame than dedicated FAC dockets and in a way that invites more input from stakeholders.
>
> **Performance-based regulation proceedings.** Proceedings that focus on investigating or implementing performance-based regulation (PBR) are another potential venue for FAC reform. The purpose of fuel-cost sharing is to better align the utility's incentives with the interests of customers and society, which is precisely the definition of

"It is one thing to identify a needed reform—and a different thing entirely to make it happen. The most fruitful strategy will vary by state, and it may also vary by utility."

[18] The structure of PUC docket searches varies greatly—some are relatively intuitive while others can be very difficult to navigate. If you have trouble with the docket search (or more general questions about what to look for), PUC staff are often willing assist if asked.

[19] To become an intervenor, a party must typically submit a request to the PUC that justifies why they should be granted intervenor status. Generally this means showing that they have a compelling interest in the outcome and that they will make some kind of unique/valuable contribution because they represent a particular group/perspective. The PUC will then either grant or deny them intervenor status.

PBR. In other words, fuel-cost sharing can be considered a PBR mechanism, and it is therefore appropriate to discuss in PBR proceedings.

Special dockets. Commission rules vary on the authorized scope and process for dockets on special topics. However, in nearly every state, a commission could open a special docket to review current fuel-cost recovery policies, consider the implications of updating these policies, and solicit public input. In some cases, a legislative hearing can spur a commission to open a special docket, and in other cases customers or other stakeholders can petition it to do so.

Public utility commissions vary greatly across states. Some may quickly recognize the problems created by 100 percent pass-through policies and act decisively to change them. In many cases, this type of response is driven by a particularly proactive commission member, so it is worthwhile for advocates to consider which commissioners may be inclined to act as champions for reform. Other commissions may not be receptive to the idea of addressing FAC reform without outside pressure.

How to Enlist Other Actors to Encourage a Commission to Act

Where a public utility commission is not inclined to take up the issue of FAC reform or is prohibited from doing so, advocates should consider enlisting the help of other parties. These include the following:

State Legislators. Though setting utility rates is the commission's responsibility, state legislators may be able to direct or encourage the commission to take action. For example, lawmakers could hold a hearing on the FAC, introduce legislation directing the commission to align its mission and operations with state policy goals, distribute sign-on letters for colleagues to join them in encouraging commission attention to fuel-cost pass-through policies, or hold stakeholder meetings on the topic.

Governors. Governors may also be able to encourage FAC updates. For example, a governor may be able to issue an executive order requiring the commission to consider or recommend reforms that align its activities with affordability or climate goals, or one that provides guidance about key design criteria (e.g., what constitutes "the public interest" for the purpose of regulatory decision-making). Also, in many states the governor is responsible for appointing commission members. In these cases, the governor could prioritize FAC reform as a significant consumer protection agenda item when appointing (or reappointing) individuals to serve on the commission.

Attorneys general. In some states, the attorney general can petition the public utility commission to open a proceeding to consider a particular issue—which could include FAC reform. Also, in most states, an attorney general can initiate a review of confidential information in fuel-supply agreements to determine whether alleged trade secret information meets the legal standard for being withheld from public view. Such a review could examine key contract terms, such as guaranteed delivery volumes regardless of need, as well as cost or price escalators that are above consumer price index averages. Some attorneys general also serve as the consumer advocate, which may give them the power to request commission dockets and take other actions to support FAC reform.

Utilities. Since the idea of FAC reform is to expose utilities to a share of the fuel-cost risk, they may not be in favor of updating the policy. However, in some cases a utility may be receptive to the idea if it expects to be able to profit by reducing fuel costs. Utility proposals often carry substantial weight with both public utility commissions and legislators, so utility support of reform can help move the process forward.

> "Exactly which steps will be needed might not be clear at the outset, and advocates should be prepared to adapt their strategy if they encounter twists and turns on what they had imagined would be a straight path. However, to be successful the most important thing is to get started."

Though the recommendations discussed are broadly applicable, every public utility commission is unique. FAC reform advocates can tailor their approach to their particular commission by researching its processes, mission, and relevant recent decisions, as well as the attitudes and policy positions its members demonstrate through their statements and actions.

How to Achieve Reform Through Legislative Action

In all states, a public utility commission can only operate within the constraints of state statutes, which are established by state legislatures.

In some states, the legislature has enshrined the FAC into statute. In these states, the public utility commission alone will not be able to update the policy since the legislature must first amend the statute. Where this is the case, would-be changemakers should develop a legislative strategy prior to—or at least in parallel with—their efforts to engage the commission.

In other states, the legislature has provided the public utility commission with the statutory authority necessary to revise the fuel-cost pass-through policy. In these states, advocates may wish to focus their efforts solely on the commission. However, even in these states, a legislative route to change is possible. For example, state lawmakers could introduce legislation to reform the FAC, even if the existing policy was implemented by the commission.

When drafting a bill, state legislators often meet with other lawmakers and affected parties to inform policy design and secure buy-in. Advocates should be aware that this may occur, and they may even wish to encourage their legislative champions to meet with utility representatives, consumer advocates, and other stakeholders. These parties may be more open to policy reforms when consulted early and away from the media attention that can occur once a bill is introduced or a hearing is in progress, and meeting with them may also result in better policies. However, utilities or other stakeholders may also use this opportunity to urge lawmakers to weaken or abandon the proposed reforms. To guard against this possibility, advocates can educate their legislative champions ahead of time about the arguments against reform that they are likely to hear and whether those arguments are reasonable.

Depending on the state's policies governing communication between lawmakers and commissioners, legislators may also wish to engage commissioners directly in crafting statutory reforms to fuel-cost pass-through policies. Some commissioners may choose to be deeply involved in such discussions, and they may even be willing to endorse specific legislative changes or testify at public hearings. Other commissioners may be reluctant to step outside of their quasi-judicial role in this way, even if they agree that a legislative update would be beneficial.

Advocates interested in legislative reform can increase the chances for success by providing their legislative champions with specific policy recommendations and examples to follow. In particular, advocates would be wise to point to precedents for FAC reform from other states, as lawmakers may be reluctant to act if they believe they will be the first state to implement such a change.[20]

How to Get Started on Reforms in Your State

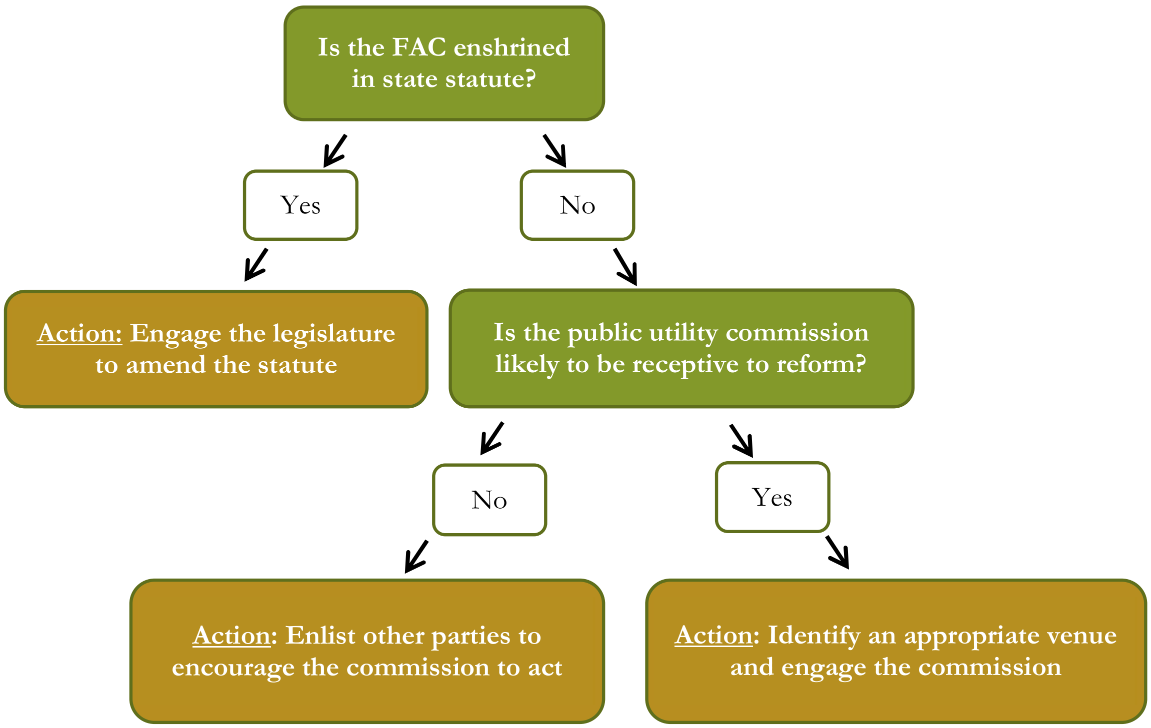
Achieving fuel-cost pass-through reform in a state may be a complex process, as advocates may need to intervene in arcane regulatory proceedings, navigate legislative policymaking, and/or enlist the support of other parties. The process may be relatively quick, but it could also take years to update a FAC policy.

Exactly which steps will be needed might not be clear at the outset, and advocates should be prepared to adapt their strategy if they encounter twists and turns on what they had imagined would be a straight path. However, to be successful, the most important thing is to get started.

Once advocates have decided they want to reform the policy in their state, they are ready to start crafting a strategy. Figure 5 illustrates the key questions that advocates embarking on this process will face.

[20] We provide some examples of states that have implemented FAC reforms later in this primer, and national nonpartisan organizations like the National Conference of State Legislators may be able to provide additional information.

Figure 5. Key Steps for Achieving Fuel Adjustment Clause Reform



Key Policy Considerations

Though the concept of fuel-cost sharing is simple, this reform can be implemented in a variety of ways. In addition, there are other reforms that could also help address related problems. When considering ways to reform an existing FAC, the following topics are worthy of consideration.

Amount of Fuel-Cost Sharing

When designing a fuel-cost sharing policy, advocates should consider the degree of sharing between the utility and its customers. For example, a utility could be responsible for just 5 percent of fuel costs (i.e., passing through 95 percent to customers) or for 20 percent (i.e., passing through 80 percent to customers). The ideal sharing percentage is a level that is high enough to motivate the utility to keep its fuel costs in check, but low enough that the utility is not exposed to unreasonable levels of risk and volatility.[21]

There is not one "best" sharing amount that should be applied to all utilities because utilities vary in multiple ways. For example, utilities rely on different mixes of fuel- and non-fuel generation sources, and they face different risk profiles in their jurisdictions.

[21] If the utility is exposed to a level of risk that is excessive, it could make it harder for the company to access low-cost capital. This could drive up its cost of capital (and by extension, the rates it must charge customers to remain financially whole), and at the extreme it could even create cash-flow problems severe enough to prevent it from serving its customers. While moderate sharing percentage would be unlikely to cause such problems, there is an upper limit to how much sharing is in customers' best interest.

Symmetry

Another design question is whether a fuel-cost sharing mechanism should be symmetrical or asymmetrical. A symmetrical mechanism shares the same percentage regardless of whether the actual fuel costs are higher or lower than expected. An asymmetrical mechanism shares a different amount in each case. Both symmetrical and asymmetrical sharing can be structured to provide both rewards and penalties.

For example, a commission may design a mechanism with a higher pass-through percentage when fuel costs are lower than expected (thus passing more of the savings on to customers) than when fuel costs are higher than expected. Such a mechanism can direct more of the benefits of fuel-cost savings to customers—but it also weakens the utility's incentive to pursue opportunities to reduce fuel costs below a certain level. Symmetrical mechanisms also tend to be easier for customers to understand than asymmetrical mechanisms. These tradeoffs should be carefully considered when deciding between symmetrical and asymmetrical designs.

Straight Sharing Versus Sharing Bands

The simplest structure for a fuel-cost sharing mechanism is to always require the same level of utility fuel cost responsibility (e.g., 10 percent) regardless of how much the utility's actual costs deviate from expectations. This approach, which is sometimes call "straight sharing," is the most common among existing fuel-cost sharing policies.

Another option is to use bands (also sometimes called thresholds). For example, a regulator could adopt a mechanism that performs no true-up if actual fuel costs fall within 25 percent of the expected value (this is called a "deadband"), a 90 percent true-up if actual costs are 25-75 percent greater than or less than that value, and a 100 percent true-up if they deviate by more than 75 percent. Figure 6 illustrates this hypothetical banded design.

Figure 6. Example of a Policy Design with Sharing Bands

In this example, the pass-through amount increases as the size of the deviation from the expected fuel cost becomes larger. Such a design can reduce the risk to the utility posed by large fuel-cost spikes, as well as the risk to customers of paying for large windfall profits if fuel costs dip very low. Alternatively, sharing bands could be used to increase (rather than decrease) the utility's risk exposure as fuel costs deviate more from the expected level; this could greatly increase the utility's incentive to reduce its reliance on fuel. Sharing bands could also be deployed in an asymmetrical fashion.

While banded designs can reduce the risk of extreme outcomes to the utility or its customers, they can also create uneven incentives. For example, a banded design that passes through 100 percent of fuel costs beyond a certain threshold dissolves the utility's financial incentive to reduce costs beyond that threshold. In addition, banded designs can be harder for customers to understand and more complex to administer than straight sharing.

Forecast Versus Historical Prices

Fuel-cost sharing mechanisms in place today share the difference between the actual fuel costs a utility incurs and the costs it was expected to incur. These "expected" costs can be based on either a forecast (i.e., a forward-looking estimate) or historical values. Forecasts are the most common approach used today, but that does not necessarily mean they are the best choice.

Traditional 100 percent pass-through policies typically utilize forecasts to set the base rates that the FAC then trues up, and most states that have adopted fuel-cost sharing have continued to rely on them. Forecasts may also be preferred because they can be tailored to reflect changing conditions—but, in reality, the accuracy of fuel-cost forecasts may be low. This is particularly true for forecasted natural gas costs, as this fuel is subject to substantial price volatility that is hard to predict.[22, 23]

However, forecasts have another drawback in the context of fuel-cost sharing: they open the door to possible gaming. Specifically, if the utility is able to inflate the forecast, it will be rewarded with a greater amount of "savings" relative to it (and also be less likely to have to bear a share of any "overspends"). It is important to note that any such gaming will not reduce the utility's financial incentive to seek savings once the forecast is adopted – so the fuel-cost sharing mechanism will still encourage the utility to reduce fuel costs. However, if the utility manages to game the forecast this will increase the costs of the policy to customers.[24]

The alternative is to use historical spending to set the expected fuel-cost baseline. Relying on historical actuals rather than forecasts avoids the gaming problem just described, and it is also more straightforward to calculate.

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[22] The price volatility of natural gas is driven by multiple factors. These include domestic transportation and storage constraints, shifting levels of international demand, and global supply-chain disruptions (e.g., due to extreme weather events and geopolitical events).

[23] Deloitte, See: https://www2.deloitte.com/ca/en/pages/resource-evaluation-and-advisory/topics/deloitte-canadian-price-forecast.html

[24] The company will have the same financial incentive to reduce fuel costs because the utility's marginal incentive (i.e., the reward it can earn for reducing fuel costs by the next increment) is not changed by the level of the forecast. For example, imagine a utility that is subject to a 90% pass-through policy and that is expected to use 100 units of fuel at $5/unit. If this utility can find a way to spend $4/unit on fuel instead of $5/unit, it will earn a $10 reward for doing so (i.e., 100 units x $1/unit * 10%). If these are real savings that would not have occurred without the utility's effort, everyone wins: the utility gets its $10 reward and customers receive $90 of savings. However, if the utility can convince its regulator that the price of fuel is likely to be $6/unit instead of $5/unit, it will earn a $10 reward for doing nothing (i.e., for spending $5/unit) and then another $10 for reducing its spending to $4/unit. Either way, the utility earns the same incentive ($10) for reducing its fuel costs from $5/unit to $4/unit, so its marginal incentive to pursue this savings opportunity is the same. However, if the utility is able to inflate its forecast to $6/unit, its customers will pay an extra $10 incentive and receive nothing in return.

However, relying on historical spending could itself create an incentive problem under certain policy designs. When the utility's historical spending is used to set the baseline, reducing fuel costs in one year will reduce the expected-cost baseline in future years. This means that if the utility's reward for reducing fuel costs now is not large enough to offset the burden of operating under a lower baseline in the future, the utility will not be motivated to reduce its fuel costs. This situation is most likely to occur where an asymmetrical design is used that requires a utility to bear most of the cost when actual fuel prices are higher than expected, but which passes on most of the savings to customers when they are lower than expected.

Transparency

In many states today, the moral hazard problem created by FACs is compounded by a lack of visibility into fuel-supply contracts. While commission staff often have access to otherwise undisclosed contracts and key terms, they may not have the time or expertise to complete a thorough review on their own. When advocates and other stakeholders are barred from accessing key documents, they cannot identify potential prudency issues and flag them for the commission and its staff to consider. The end result is less regulatory scrutiny of utility fuel expenditures.

Though fuel-cost sharing addresses the moral hazard problem created by traditional 100 percent pass-through policies, transparency is still important. State lawmakers and utility regulatory commissions can take steps to ensure that the key terms of utility fuel-supply contracts are transparent to customers and other stakeholders, while protecting necessary trade secrets as appropriate. Such terms include (but are not limited to) pricing, annual escalators or other pre-determined price increases, minimum delivery amounts, and contract length.

Disallowance on Prudency Grounds

The purpose of fuel-cost sharing is to motivate the utility to seek ways to reduce its fuel costs. However, it is not the only policy tool available to accomplish this objective. Another option is to identify fuel-cost savings opportunities that are available to the utility and to disallow cost recovery if the utility fails to take advantage of these opportunities.

For example, a regulator might determine that a certain utility could reduce its reliance on natural gas for power generation by 5 percent a year if it aggressively pursues a demand-side portfolio of energy efficiency, demand response, and load-shifting measures. The regulator could then allow the utility to pass through all natural gas costs up to this level via the existing FAC, while disallowing any recovery of costs beyond this level on the grounds that they were imprudently incurred.[25]

As another example, a regulator could demonstrate a willingness to scrutinize all fuel costs presented for recovery and disallow any for which the utility cannot convincingly demonstrate prudency. This more rigorous prudency review could encourage the utility to pursue opportunities to reduce fuel costs, to be more transparent as a strategy to show the regulator that it has been making an effort, and to reduce its reliance on fuel-fired generation over time. For this strategy to be effective, however, it must be clear to the utility that disallowance is a real and substantive risk—simply

[25] The allowed level of natural gas usage could also be adjusted to reflect actual weather conditions. Such a normalization could reduce the risk of windfall losses or gains due to usage fluctuations driven by weather events, which are not under the control of the utility.

applying a slightly higher level of review to an existing FAC docket that currently functions as a rubber stamp is unlikely to be effective.

Hedging

Fuel-cost sharing can reduce the risk posed by fuel-price spikes by encouraging the utility to secure more favorable fuel-supply contracts and reduce its reliance on fuel-based generation sources. However, another way to reduce the risk of price volatility is hedging. Hedging refers to the use of financial instruments to mitigate the risk of unexpected negative investment outcomes. Requiring that utilities hedge can reduce the risk of fuel-price spikes to customers, but hedging also means incurring an additional cost or risk that is then passed on to customers. Whether to encourage or require hedging (or particular kinds of hedging) is a question that should be considered whether or not fuel-cost sharing is in place.

Purchased Power

Fuel-cost sharing is only relevant for vertically integrated utilities that purchase fuel to generate power and then sell that power to customers. However, some regulated utilities do not own generation (these "wires only" utilities are the norm in restructured states), and even vertically integrated utilities may buy substantial amounts of power from other parties to serve their customers. These parties may include independent power producers, other regulated utilities, and unregulated affiliate companies of the purchasing utility.

Typically, the cost of purchased power is recouped in the same fashion that fuel costs are: as a 100 percent pass-through to customers. A sharing mechanism can be implemented for purchased power in the same way as for fuel costs, but whether this makes sense will depend on local circumstances.

In cases where a regulator is implementing fuel-cost sharing for a vertically integrated utility, applying an equivalent sharing policy to purchased power should be seriously considered—because without this, gaming may occur. For example, during a natural-gas price spike a utility that is subject to fuel-cost sharing but not purchased-power cost sharing could substitute spot-market purchases for its own generation. Such a move would likely raise rather than lower costs to customers, contrary to the goal of the fuel-cost sharing policy. Applying sharing to both fuel and purchased power could avoid this type of behavior.[26]

However, in cases where the utility does not own generation, the case for applying a sharing policy to purchased power is less clear. For a utility that has substantive opportunities to lower these costs through its own actions, a purchased-power sharing policy could make sense. For instance, a wires-only utility may be able to lower the cost of the power it purchases by aggressively promoting energy efficiency programs to its customers. It could also lower costs by negotiating better contracts, switching to different suppliers, or helping customers shift demand to lower-cost hours (e.g., via demand-response programs, managed EV charging, and time-varying rates). However, if a wires-only utility has limited control over purchased-power prices (e.g., because it purchases most of its power through wholesale markets where it acts as a price-taker rather than as a price-setter) and

[26] If a purchased-power sharing policy is adopted alongside a fuel-cost sharing policy, they should be equivalent—but this does not mean identical. Since fuel costs only make up a portion of purchased-power costs, the sharing factor for purchased power could be lower than the one applied to the utility's own fuel costs.

limited ability to influence customer behavior (e.g., because a separate state entity is responsible for administering demand-side management programs), it may make little sense to apply a sharing mechanism to its purchased power costs.

Stakeholders should also note that purchased power includes electricity generated from both fuel- and non-fuel resources. This means that purchased-power cost sharing will not necessarily drive decarbonization in the same way as fuel-cost sharing would be expected to. Where reducing carbon emissions is an important policy goal, additional strategies to accomplish this aim could be considered. For example, the sharing mechanism could be designed in a way that distinguishes between different types of generation resources (e.g., it could apply a higher pass-through percentage to renewables than to fossil fuel-fired generation).

Examples of State Fuel-Cost Sharing Policies

A few states have adopted fuel-cost sharing mechanisms to varying degrees, and interest in this neglected aspect of utility regulation has been growing in recent years. However, advocates should keep in mind that just because a particular design feature is common does not necessarily mean it is a good idea. Being familiar with existing forms of fuel-cost sharing policies but also willing to advocate for improvements to them is likely to result in the best outcome. Below we discuss a few examples of fuel-cost sharing policies that have been adopted by states.

Hawaii

The Hawaii Public Utilities Commission adopted fuel-cost sharing for the Hawaiian Electric Companies (HECO) in 2018.[27] The Energy Cost Recovery Clause (ECRC) utilizes a straight-sharing approach anchored to a forecast of fuel costs, in which the utility passes through 98 percent of fuel costs to customers regardless of whether its actual costs are above or below the forecast. HECO's annual financial exposure under the policy is capped at $2.5 million. In 2022, the Commission invited intervenors to consider proposals to modify the risk sharing component of the ECRC, signaling an openness to increase the sharing factor—though no decision to adjust it has yet been made.[28]

Idaho

The Idaho Public Utilities Commission adopted the Power Cost Adjustment (PCA) mechanism for Idaho Power in 1992 to share power supply costs between the utility and its customers. The mechanism features a straight sharing design, relies on forecasts, is symmetrical, and includes purchased power. The PCA initially passed through 90 percent of power supply costs, but in 2009 the commission increased this to 95 percent. In approving this change, it explained that "power supply cost volatility has increased significantly since the PCA was implemented, and that with increased volatility, a sharing percentage of 5% still provides strong incentive for the Company to make prudent power purchases."[29] In 2009, the commission also adopted a mechanism called the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain Power. The ECAM features straight sharing with a 95 percent pass-through, has a symmetrical design, employs forecasts, and includes purchased power.[30]

Wyoming

In 2011, the Wyoming Public Service Commission adopted the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain Power. The ECAM was a modification of a prior sharing policy called

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[27] Hawaii Public Utilities Commission, Final Decision and Order No. 35545, Docket No. 2016-0328, June 22, 2018, https://puc.hawaii.gov/wp-content/uploads/2018/06/DO-No.-35545.pdf

[28] Hawaii Public Utilities Commission, Decision and Order No. 38429, Docket No. 2018-0088, June 17, 2022, pg. 56.

[29] Idaho Public Utilities Commission, Order No. 30715, Case No. IPPC-E-08-19, January 9, 2009, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE0819/OrdNotc/20090109final_order_no_30715.pdf

[30] Idaho Public Utilities Commission, Order No. 30904, Case No. PAC-E-08-08, September 29, 2009, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE0808/OrdNotc/20090929final_order_no_30904.pdf; Idaho Public Utilities Commission, Order No. 35419, Case No. PAC-E-22-05, May 26, 2022, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE2205/OrdNotc/20220526Final_Order_No_35419.pdf

the Power Cost Adjustment Mechanism (PCAM), which was created based on a statute that allowed the commission to use non-traditional rate tools to optimize outcomes.[31] The ECAM trues up the utility's actual net power costs (which include fuel, purchased power, and certain other costs) to its forecasted costs in a symmetrical fashion. The ECAM previously featured a 70 percent pass-through and it employs an 80 percent pass-through today.[32]

Missouri

In 2005, the Missouri legislature enacted Senate Bill 179, and the commission implemented the first fuel adjustment clause mechanism in 2007 (and the last one in 2015). In Missouri, these mechanisms are referred to as "fuel adjustment clauses" (FACs) even if they feature fuel-cost sharing.[33] The mechanisms in place for Ameren, Evergy, and Liberty Utilities all feature straight sharing with a 95 percent pass-through.[34] This legislation was codified as Section 386.266 of the Revised Missouri Statutes (RSMo) in 2005, and also granted authority to the commission to include an incentive for efficiency and cost-effectiveness as part of the mechanism.

Wisconsin

The Wisconsin Public Service Commission was authorized by Wisconsin Statute § 196.20(4) to establish automatic adjustment clauses for regulated utilities, and the commission codified the rules for doing so as Wisconsin Administrative Code § PSC 116.03.[35,36] Under these rules, each of the state's five major investor owned electric utilities (Wisconsin Electric Power Company, Wisconsin Public Service Corporation, Madison Gas & Electric, Wisconsin Power and Light, and Northern States Power – Wisconsin) are required to file fuel cost plans.[37] Each plan includes a forecast of the utility's expected costs for fuel, purchased power, and related expenditure categories to be collected from customers. Once the utility's actual fuel (and related) costs are known, the commission can approve a true-up to collect or refund any difference that represents 2 percent of the forecasted amount. In other words, there is a 2 percent deadband where no sharing occurs and a 100 percent pass-through outside this deadband. The commission has the authority to rule on whether or not the utility's actions were prudent when determining the extent of cost recovery to be allowed. The true-up occurs through a fuel adjustment which appears on customers' bills.[38]

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31 Wyoming Public Service Commission, Memorandum Opinion, Findings, and Order, Docket No. 20000-368-EA-10, February 4, 2011, https://pscdocs.utah.gov/electric/09docs/0903515/71051ExhibitA2-9-11.pdf

32 For the present 80% pass-through policy, see the current version of Sheet No 95-6 (P.S.C. Wyoming No. 17, Original Sheet No. 95-6). For the previous 70% pass-through policy, see P.S.C. Wyoming No. 16, First Revision of Amended Original Sheet No. 95-6 Canceling Amended Original Sheet No. 95-6. Source: Rocky Mountain Power, Energy Cost Adjustment Mechanism, Schedule 95, (current tariff) https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf

33 This is different from how we use this term in this primer, where we define FAC as a 100% fuel-cost pass-through mechanism.

34 Lena M. Mantle, Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper; Office of the Public Counsel, Revised January 14, 2022, https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=939661980

35 Wisconsin Statutes, https://docs.legis.wisconsin.gov/statutes/statutes/196/20

36 Wisconsin Public Service Commission, Chapter PSC 116, March 15, 2023, https://docs.legis.wisconsin.gov/code/admin_code/psc/116.pdf

37 Wisconsin Public Service Commission, Final Decision, Docket 6680-ER-103, December 13, 2022,

38 Alliant Energy, RE: Wisconsin Power and Light Company Electric Tariff for Fuel Adjustment, Docket No. 6680-ER-103, December 21, 2022, https://apps.psc.wi.gov/pages/viewdoc.htm?docid=455114

Conclusion

Many Americans today struggle to pay their electric bills. Fuel costs often represent a large share of customer bills, and unlike most rate components these charges can vary substantially from month to month. Reducing fuel costs—as well as fuel-cost volatility—is imperative to ensuring that electricity is affordable and accessible to all.

Fortunately, electric utilities have more ways to reduce fuel costs today than ever before. These opportunities exist on both the supply and demand side (e.g., increasingly cheap solar and wind generation, distributed energy resources that shift load to lower-cost hours), and they are enhanced by supportive federal policies like the Inflation Reduction Act (IRA). However, these opportunities have not spurred a utility rush to decrease fuel costs. Why?

The answer is that most states pass 100 percent of fuel costs through to customers, which gives utilities no financial incentive to reduce these costs. If a utility finds any savings, customers reap all the benefits—and if it spends more than necessary, customers pick up the bill.

It is time for these outdated policies to change, and advocates can play important roles in this process. This primer has described the problems created by existing 100 percent pass-through policies, explained how fuel-cost sharing reforms can produce better outcomes, and provided tools that advocates can leverage to encourage reforms in their states. If these reforms are well designed, they will result in lasting benefits for customers, utilities, and the environment.